BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 165

In the Matter of:	)	PARTIAL INITIAL COMMENTS OF
	)	SOUTHERN ALLIANCE FOR CLEAN
2020 Biennial Integrated Resource	)	ENERGY, SIERRA CLUB, AND
Plans and Related 2020 REPS	)	NATURAL RESOURCES DEFENSE
Compliance Plans	)	COUNCIL

Intervenors Southern Alliance for Clean Energy, the Sierra Club, and the Natural Resources Defense Council (collectively, "SACE, et al.") respectfully submit these partial initial comments on the 2020 Integrated Resource Plans ("IRPs") of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, Inc. ("DEP") (collectively, "Duke Energy" or "Duke").[1]

INTRODUCTION

The 2020 Duke IRPs do not represent the "least-cost mix" of resource options, contrary to North Carolina law. As summarized in these comments and in the Joint NCSEA/CCEBA/SACE et al. comments, and as detailed in the supporting expert reports attached thereto, the resource mix in the 2020 IRPs is more costly, more risky and more polluting than a plan that relies on reasonable reserve margins, retires and reduces utilization of aging, inefficient, uneconomic coal plants, and maximizes cost-effective energy efficiency, demand-side management, renewable energy resources, and battery storage. Accordingly, the 2020 Duke IRPs fail to meet the requirements of state law and

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[1] SACE et al. are also submitting jointly with the North Carolina Sustainable Energy Association and Carolinas Clean Energy Business Alliance partial initial comments and an accompanying report by Synapse Energy Economics regarding the evaluation of resource options and coal retirements analysis ("Joint NCSEA/CCEBA/SACE et al. comments").

the Commission should decline to accept them as reasonable for planning purposes, and require DEC and DEP to correct any deficiencies identified by the Commission in light of these comments and those of other parties, and file revised IRPs within 60 days of the Commission's final order—before Duke Energy goes farther down the path toward imprudent investments in expensive, unnecessary and polluting gas-fired generation.

While they are non-binding planning documents, utility IRPs have major implications for important decisions that the Commission will face in the future. For example, the IRP forms the basis for a utility's decision to build or acquire a new capacity or energy resource, and typically serves as the basis for application for a certificate to build a new power plant. Assumptions and conclusions made in the IRPs also underpin utility calculations of avoided costs, which themselves affect rates paid to independent power producers and cost-effectiveness testing of demand-side management and energy efficiency programs. A showing of need in the utility's IRP serves as the basis for a new competitive procurement of renewable energy, which provides low-risk, fuel-free resources to the system while promoting indigenous resources and economic development. And most fundamentally, the IRP is the place where each utility discloses the cost of each portfolio—costs that will ultimately be borne by ratepayers.

SACE, et al. commissioned expert analyses of the 2020 Duke IRPs and supporting documents, as discussed in detail in the reports attached to these comments. Using Duke's own data, these expert consultants reached the following conclusions:

- Higher levels of demand-side management ("DSM") and energy efficiency ("EE") could avoid or defer the need for new gas-fired power plants and enable accelerated retirement of coal units. Yet Duke under-estimated the economic and achievable potential for these resources, missing the chance to reduce the cost of its resource portfolios.

- The reserve margins used in the 2020 IRPs were improperly inflated, and the Companies' forecasts for winter peak loads should be carefully scrutinized to ensure that they are not unduly driven by rare, extreme weather events. Duke's claim that it needs capacity to meet over-estimated winter peaks, coupled with Duke's under-estimate of the contribution that DSM can provide to mitigate winter peaks, could lead to costly overbuilding of gas plants that will need to be retired before the end of their useful lives.

- Absent guidance from the Commission, Duke Energy will continue to rely on single-source procurements to meet capacity and energy needs identified in its IRPs. DEC and DEP likely will proceed with large gas-only procurements, missing out on cleaner and cheaper resources. All-source procurement is more likely to result in the least-cost mix of demand- and supply-side resources than traditional single-source procurement because it harnesses market dynamics more effectively.

DISCUSSION

A. North Carolina IRP Requirements.

Duke's 2020 IRPs must be evaluated in the context of North Carolina law, which deems the operations of public utilities to be "affected with the public interest" and declares it to be the State's policy to promote adequate, reliable and economical utility service to all of its citizens and residents, and to provide just and reasonable rates and charges "consistent with long-term management and conservation of energy resources by avoiding wasteful, uneconomic and inefficient uses of energy." N.C. Gen. Stat. § 62-2 (a)(3-4).

To this end, the statute establishes a state policy of assuring that resources for future growth include use of the "entire spectrum of demand-side options" and "require[ing] energy planning and fixing of rates in a manner to result in the *least cost mix of generation* and demand-reduction measures which is achievable. . . ." N.C. Gen. Stat. § 62-2(a)(3a) (emphasis added). The statute goes on to deem it state policy to "promote harmony between public utilities, their users and the environment" and to “foster the continued service of public utilities on a well-planned and coordinated basis.” N.C. Gen. Stat. § 62-2 (a)(5), (6). Finally, the statute declares a policy to “promote the development of renewable energy and energy efficiency” through the implementation of a renewable energy and energy efficiency standard that diversifies “the resources used to reliably meet the energy needs of consumers in the State,” provides “greater energy security through the use of indigenous energy resources available within the State,” encourages “private investment in renewable energy and energy efficiency,” and provides “improved air quality and other benefits to energy consumers and citizens of the State.” N.C. Gen. Stat. § 62-2 (a)(10).

To meet these objectives, the Commission is vested with the authority to regulate public utilities, including their “their expansion in relation to long-term energy conservation and management policies and statewide development requirements, and in the manner and in accordance with the policies set forth in this Chapter.” N.C. Gen. Stat. § 62-2 (b). The General Assembly also directed this Commission under N.C. Gen. Stat. § 62-110.1(c) to:

> . . . develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power . . . and other arrangements with other utilities and energy suppliers to *achieve maximum efficiencies* for the benefit of the people of North Carolina. . . .

N.C. Gen. Stat. § 62-110.1(c) (emphasis added). The Commission must annually submit a report to the Governor and the General Assembly setting out a plan for meeting the future requirements of electricity for North Carolina, progress to date in carrying out such plan, and program regarding such plan over the ensuing year. *Id.*

The final statutory provision informing the Commission's review of IRPs is found within the Competitive Procurement of Renewable Energy Program ("CPRE") established by Session Law 2017-192. Following a 45-month procurement period, "a new renewable energy resources competitive procurement and the *amount to be procured* shall be determined by the Commission, based on a showing of need evidenced by the electric public *utility's most recent biennial integrated resource plan or annual update approved by the Commission* pursuant to G.S. 62-110.1(c)." N.C. Gen. Stat. § 62-110.8(a) (emphasis added). The initial CPRE program was approved by the Commission on February 21, 2018.[2] Thus, pursuant to N.C. Gen. Stat. § 62-110.8(a), the initial CPRE program will expire in November 2021. While Duke will file IRP update reports on September 1, 2021, those reports will not be approved prior to the expiration of the original CPRE program.

To implement the provisions of N.C. Gen. Stat. §§ 62-2(3a) and 62-110.1(c), the Commission has promulgated rules governing "least cost integrated resource planning by the utilities in North Carolina." NCUC Rule R8-60(a). Under the rules, electric utilities must develop and submit IRPs that, "at a minimum" must incorporate a "*comprehensive analysis of all resource options* (supply-and demand side)" including resources chosen to provide reliable electric utility service *"at least cost* over the planning period." NCUC Rule R8-60(c) (emphasis added). In developing their IRPs, utilities must "compare a

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[2] The use of the word "approved" in this context creates some ambiguity in that neither the IRP statute, N.C. Gen. Stat. § 62-110.1(c), nor the Commission's IRP Rule R8—60, make any reference to approval by the Commission of a utility's IRP. Rather, the Commission must determine whether or not to accept the plan as adequately and accurately providing the required information and analysis. The best way to resolve this inconsistency is to understand the phrase "approved by" in N.C. Gen. Stat. § 62-110.8(a) to mean "accepted by."

comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the *least cost combination* (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system." NCUC Rule R8-60(g) (emphasis added). The comparison must also "analyze potential resource options and combinations of resource options to serve its system needs" taking into account sensitivity to "variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation," as well as applicable "system operations, environmental impacts, and other qualitative factors." *Id.*

To ensure that a comprehensive analysis of least-cost options is undertaken and disclosed in an IRP, the Commission's rules set out the necessary elements that an IRP must include. Among other things, the IRP must consider and assess: "supply-side and demand-side resources, including alternative supply side energy resources" for the "provision of reliable electric utility service at least cost"; compliance with the Renewable Energy and Energy Efficiency Portfolio Standard ("REPS"); "the potential benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity"; any benefits of "reasonably available alternative supply-side energy resource options" including "solar thermal, solar photovoltaic, municipal solid waste, fuel cells, and biomass"; and "programs to promote demand side management" including "demand response programs and energy efficiency and conservation programs." NCUC Rule R8-60(d)-(f).

As summarized in these comments and as detailed in the attachments thereto, Duke's 2020 IRPs do not meet this Commission's applicable requirements because they fail to utilize the entire spectrum of demand-side options, use inflated reserve margins based on faulty assumptions about winter peak demand, and rely on Duke's biased assumptions about resource need, costs and availability rather than taking advantage of a competitive all-source procurement process that establishes a total system need and allows the market to inform the least-cost resource mix.

B. The Duke IRPs underutilize cost-effective demand-side management and energy efficiency.

1. Duke should analyze demand-side resources on a level playing field with supply-side resources.

The DEC and DEP IRPs underutilize cost-effective demand-side management ("DSM")[3] and energy efficiency ("EE") resources, resulting in a higher-cost resource plan than necessary. As discussed in the following subsection, there are potentially substantial levels of additional untapped energy efficiency and DSM (demand response) resources available to reduce system costs, further accelerate Duke's coal retirement schedule, and help North Carolina achieve its carbon reduction goals.

Duke's IRPs do not optimize demand-side resources for these purposes, however. Instead, Duke limits DSM and EE in its IRPs to just two blocks of predetermined levels, equating to a combined 2,050 MW or 3,350 MW for DEC + DEP, depending on the scenario. DSM and EE were not competitively modeled against supply-side alternatives

[3] North Carolina statutes and Commission rules define "demand-side management" (or "DSM") to refer to what is more commonly known as "demand response" in other jurisdictions, which typically use DSM as a broader term that encompasses both demand response and energy efficiency.

in Duke's IRPs, nor does Duke employ any mechanism to validate whether its proposed supply additions would in fact be less expensive than adding more DSM/EE to the overall resource portfolio mix. Higher levels of DSM/EE may very well be warranted even beyond the 3,350 MW level, but it is noteworthy that Duke actually uses the lower 2,050 MW savings level in its analysis of the "Earliest Practicable Coal Retirements" scenario—a significant oversight. Ultimately, increased investment in DSM/EE could not only speed up retirement of coal generation, it can delay, reduce, or avoid the need for more expensive new fossil gas to replace portions of the soon to be retired coal capacity, thereby resulting in lower utility system costs and a lower-cost resource portfolio.

The Commission should require Duke to conduct a more dynamic evaluation of DSM/EE resources. At a minimum, this should include a requirement that Duke's proposed supply-side resource additions be analyzed head-to-head against higher levels of DSM/EE savings. To the extent that higher levels of DSM/EE are found to reduce costs in any of the scenarios in Duke's 2020 IRPs, the higher levels of DSM/EE should be added to those scenarios and the new supply resources reduced accordingly. The Commission should also require Duke to use industry-standard practices and its transition to the EnCompass model to implement an Energy Efficiency as a Resource methodology into future IRPs. Ultimately, doing so will help Duke, the Commission, and our State advance current efforts to retire coal generation, reduce carbon emissions, and lower costs paid by customers on their monthly electric bills.

2. Duke's Market Potential Study underestimated cost-effective DSM and EE.

Duke used the estimates of DSM and EE potential developed by its consultant Nexant in the Duke Energy EE and DSM Market Potential Study dated June 2020

("MPS") as the basis for its projections of EE/DSM savings over the IRP planning horizon. DEC and DEP each blended their five-year program planning forecast into the long-term achievable potential projections from the MPS. The EE savings were used as a reduction to the load forecast, while the DSM savings were treated as resource options.

SACE, et al. retained Jim Grevatt, a consultant with 30 years' experience in the energy efficiency industry, to review the MPS. Mr. Grevatt's report, "Review of DEC and DEP Market Potential Studies," is attached as Attachment 1 to these comments. Mr. Grevatt found that the Duke MPS significantly underestimates the potential EE and DSM savings in Duke's territory due to a variety of omissions, unreasonable assumptions, and arbitrary limitations in the study design. In particular, due to these flaws, the Duke MPS significantly underestimated DSM potential in winter, a critical factor given that winter peak demand drives much of Duke's planning. Indeed, Duke's Winter Peak Study,[4] which included an assessment of several innovative approaches that the MPS excluded, identified significantly more winter peak DSM potential than the MPS. Because Duke relied on the MPS as the basis for its EE and DSM projections in the IRP, those projections should be revised to account for higher, more realistic estimates of potential.

Mr. Grevatt's report identifies three major categories of omissions in the MPS. First, the MPS failed to account for potential savings that could result from emerging technologies, instead only considering "existing technology and market trends as observed with currently available data." Second, the MPS failed to evaluate a variety of

[4] Tierra Resource Consultants, Dunsky Energy Consulting, and Proctor Engineering Group, *Duke Energy Winter Peak Analysis and Solution Set*, *Duke Energy Winter Peak Demand Reduction Potential Assessment*, and *Duke Energy Winter Peak Targeted DSM Plan, December 2020* (collectively, "Winter Peak Study"), attached as Attachments 2, 3, and 4.

measures that are known today and used to achieve savings by numerous EE programs in other jurisdictions. Finally, the MPS failed to consider new or enhanced customer engagement strategies or program designs that Duke could employ to increase customer participation rates.

In addition, Mr. Grevatt identified four major issues with the MPS study design. First, the MPS made unreasonable assumptions regarding commercial and residential end-uses that result in an underestimation of savings. Second, the MPS failed to account for increasing measure savings due to technology improvement and decreasing measure and program costs driven by economies of scale, and unreasonably constrained its calculation of achievable potential by limiting it to measures already included in Duke's EE portfolio. Further, the MPS calculates the achievable potential based on historic participation rates, without regard for the potential impact that program delivery improvements could have on participation and savings.

Finally, the MPS used the Total Resource Cost ("TRC") instead of the Utility Cost Test ("UCT") to screen for cost-effectiveness, even though the UCT has been approved by the Commission as the primary cost-effectiveness test for Duke and is a more relevant measure of the value EE and DSM provide to the utility system. Use of the TRC depressed the estimates of economic DSM and EE potential. The MPS calculated and presented levelized costs by sector for DEC and DEP, presented from the TRC perspective. The TRC test, however, includes participant costs but does not include a variety of participant benefits; as a result, the test tends to understate cost-effectiveness and overstate levelized costs, making EE and DSM resources seem misleadingly expensive when compared with other resource options. Moreover, the TRC is not the most relevant measure of how EE and DSM can reduce utility system costs – that is more appropriately measured by the UCT. Since minimizing utility costs while maintaining safe, reliable service is the core purpose of an IRP, it makes no sense that Duke uses asymmetrically calculated TRC results to determine the optimal level of EE and DSM in its IRP.

The fact that the results of the MPS based on the TRC were overly conservative and not reflective of the true potential for EE was demonstrated by a sensitivity analysis that Nexant performed for economic potential using the UCT, which found significantly higher economic savings potential for both the residential and commercial sectors than using the TRC. The results of this sensitivity indicate an increase of economic efficiency potential by 37%, 46%, and 15% for the residential, commercial, and industrial sectors in DEC, and an increase of 51%, 51%, and 8% for the residential, commercial, and industrial sectors in DEP.

Mr. Grevatt also compared the potential winter peak capacity savings identified in the MPS to the results of the December 2020 Duke Energy Winter Peak Demand Reduction Potential Assessment, prepared by Dunsky Energy Consulting in partnership with Tierra Resource Consultants "WPDR Potential Assessment".[5] His review showed that, due to many of the same issues identified above with respect to EE savings in the MPS, Nexant significantly underestimated DSM potential in winter where the need is growing. Indeed, the WPDR Potential Assessment, which included an assessment of several innovative approaches that the MPS excluded, identified significantly more winter peak potential than the MPS: the WPDR Potential Assessment's "Max" scenario

[5] Attachment 3.

identified nearly twice the winter peak potential identified in the MPS's "Base" scenarios, and roughly 70 and 77% more winter peak potential compared to the MPS "Enhanced" scenarios for DEC and DEP, respectively.[6] This is particularly important because, as was discussed in both the WPDR Potential Assessment and the 2020 IRP, Duke's winter peak capacity requirements are growing faster than its summer peak requirements and are increasingly driving the resource plan.

In light of the flaws identified by Mr. Grevatt's review, SACE, et al. recommend that the Commission require DEC and DEP to revise their 2020 IRPs using updated EE and DSM assumptions, as follows:

1. Recalculate levelized costs using the Commission-approved UCT rather than the TRC. The levelized costs as presented in the Nexant studies should not be used as an input to the IRP. Instead, the Commission should require Duke to recalculate levelized costs from the UCT perspective, as the sum of program incentives and administrative costs divided by the discounted sum of lifetime energy savings, and revise its IRP using these updated cost assumptions. This should only be done after the MPS is revised to address potential savings more fully.
2. Revise its assessment of EE/DSM potential to account for emerging technologies, measures not currently included in its program portfolio, and modifications and improvements Duke could make to its current marketing efforts and program designs that could increase program participation. In this assessment, Duke should

[6] *Id.* at 22. Note that in both cases the projected savings are incremental to DSM savings already achieved by Duke.

give particular attention to programs to address winter peak, consistent with the findings of the WPDR Potential Assessment.

3. Re-evaluate its calculations of EE/DSM potential to align its allocation of residential and commercial load to the “miscellaneous” end-use category with EIA data.

C. The reserve margins used in the 2020 IRPs were improperly inflated.

The planning reserve margin is a key element of an IRP because it determines how much extra capacity the utility maintains on its system to meet demand in the event of an outage or other unanticipated capacity gap. Both of the Duke IRPs use a 17% winter planning reserve margin based on the recommendations of Resource Adequacy Studies (“RA Studies”) conducted by Astrapé Consulting. The results of the RA Studies identified a 16% winter planning reserve margin for DEC, 19.25% for DEP, and 16.75% for a “combined” case, ultimately recommending 17% for each utility. However, the RA Studies had several fundamental flaws that led to overstated resource adequacy risks. These overstated resource adequacy risks in turn led to inflated planning reserve margins. If the flaws in the RA Studies were corrected, a 14.5% summer planning reserve margin and 16.5% winter reserve margin would be more appropriate. The use of overly high reserve margins in the IRPs means that the Companies plan to add too much new capacity on the system, which would add unnecessary costs for ratepayers.

The purpose of the RA Studies was to identify the planning reserve margin necessary to satisfy a “one day in ten years” resource adequacy standard. The “one day in ten years” resource adequacy standard is satisfied when an unanticipated capacity gap will cause firm load shed (i.e. power outages) due to insufficient generating capacity no more often than one day for one or more hours every 10 years. The “one day in ten years” standard has frequently been used by utilities to approximate a reasonable level of reliability.

The RA Studies have substantially overstated winter resource adequacy risk and this inflated risk drastically impacted the resulting reserve margins. The primary flaw of the RA Studies was using an inaccurate approach to estimate the impact of extreme cold on loads. The RA Studies used the neural network approach in order to associate loads with temperatures. The neural network approach uses a series of algorithms in order to determine a relationship between two sets of data—in this case, historical loads and historical temperatures. However, at lower temperatures, where there are fewer observations and thus insufficient data for the neural network approach to be applied, the RA Studies used a simpler regression analysis to extrapolate load levels.

The extrapolation methodology used to determine loads at lower temperatures was severely flawed. First, the approach assumed that for each additional degree the temperature drops, load increases by the same amount as at around 20 degrees. This assumption is incorrect. As temperatures continue to fall below a certain point, load does not continue to increase consistently because customers are already operating all of their available heating equipment. Second, the regression analysis included observations up to 21 degrees; when these higher temperatures are excluded, the incremental impact of lower temperatures is much lower. Finally, the method of combining the results of the regression analysis with the results of the neural network approach led to extreme and nonsensical load values. Prior to filing future IRPs, the Companies should study the relationship between extreme winter weather and load, and develop more accurate methods for estimating the impact of extreme winter weather on load.

In addition, the RA Studies used 39 years of temperature data, from 1980 through 2018, and assigned equal weight to each year. This set of years includes many instances of very extreme cold that have not been seen in Duke's service territory, or only rarely seen, for decades. Inclusion of these extreme cold events overstates the likely frequency of such extreme cold going forward, amplifying the effect of overstating the impact of extreme cold on winter peak loads. These extreme cold events had an overwhelming impact on the results of the RA Studies.

In December 2020, the Companies released a Winter Peak Study that identified the key drivers of winter peak loads and evaluated potential demand-side management programs to mitigate winter peak loads. The results of the Winter Peak Study and the RA Studies were highly inconsistent. The Winter Peak Study identified a "Study Peak Day," which had the highest winter coincident peak demand.[7] The RA Studies modeled load values over 13% higher than the highest load on the Study Peak Day and the vast majority of loss of load scenarios in the RA Studies occurred at loads in excess of the Study Peak Day's highest load. Nevertheless, the Winter Peak Study did not discuss the possibility of winter peak loads higher than Study Peak Day's, evaluate what customers and end uses could contribute to loads higher than the Study Peak Day, or identify or evaluate programs tailored to mitigating loads greater than the Study Peak Day. While the RA Studies recommend a reserve margin driven by extreme winter loads in excess of the Study Peak Day, the Winter Peak Study does not even acknowledge such loads are possible.

[7] Attachment 2 at 9.

The RA Studies also overstate winter resource adequacy risk by including an unreasonable amount of forced power plant outages. The RA Studies included 400 MW of forced outage to account for the fact that some portion of capacity will be offline at extreme temperatures. The 400 MW figure was selected because it represented "[t]he average capacity offline below 10 degrees for DEC and DEP combined" between 2016 and 2019. However, the 400 MW is not an average, but is instead based on a single occurrence during that period. This single instance was unique in several respects and not representative of other instances of cold-related outages. Removing the 400 MW of forced outages would lower the reserve margins by approximately 1% per utility.

Finally, the Companies failed to adequately explore demand-side management options for extreme winter weather events. The RA Studies indicated that these extreme, infrequent events were the primary cause of loss of load events. The Companies should engage with customers and stakeholders to develop programs for addressing these rare and brief spikes in load. An additional 500 MW of winter demand response would eliminate the majority of winter load loss events.

These findings regarding the Companies' RA Studies, along with corresponding recommendations for improvement, are discussed in detail in the Wilson Energy Economics report attached as Attachment 5 (the "Wilson Resource Adequacy Report"). Based on the above flaws in the RA Studies, SACE, et al. recommend that the Commission require DEC and DEP to implement the following recommendations in their 2020 IRPs and future IRPs:

1. If the Companies believe winter peak loads in excess of the Winter Peak Study's Study Peak Day are likely to occur, the Companies should study the customers

and end uses that contribute to those extreme loads. The Companies should then engage with customers and develop tailored programs for shaving these rare and brief spikes.

2. The Companies should study the relationship between extreme winter weather and load, and develop more sophisticated methods for estimating the potential impact of future extreme winter weather on load.
3. The Companies should research the potential for load forecast errors due to economic forecast errors or other causes.
4. The Companies should provide additional scenario analysis and sensitivity analysis of the RA Studies, and allow stakeholders to request additional sensitivity analysis through discovery.
5. The Companies should consider defining an alternative metric for expressing and communicating target reserve margins. Possible examples include the use of an aggregate capacity value measure in the numerator or a 90-10 extreme forecast peak load value in the denominator. These alternative metrics would be more robust and stable over time as load patterns and the capacity mix change.

D. The Commission should adopt an all-source procurement approach to identifying the need for new resources and selecting the best resource mix to meet the need.

Absent guidance from the Commission, Duke Energy will continue to rely on single-source procurements to meet those needs. DEC and DEP likely will proceed with large gas-only procurements, missing out on cleaner and cheaper resources, which will result in a resource mix that is not least-cost. All-source procurement offers an efficient way to ensure that this upcoming need is met with least-cost and clean resources.

SACE, et al. commissioned John D. Wilson of Resource Insight, Inc. to evaluate the feasibility of implementing all-source procurement in the Carolinas. Mr. Wilson is the lead author on a recent report on all-source procurement prepared for Energy Innovation and the Southern Alliance for Clean Energy.[8] Drawing heavily on that report, the report Mr. Wilson prepared for this proceeding[9] illustrates the benefits of all-source procurement and offers a guide to implementing it in the Carolinas.

All-source procurement is a unified resource acquisition process that proceeds in two steps. First, a utility and its regulators determine the need the utility will have to meet. The utility's need is based on its forecast load, plus any retirement of existing generation sources. System need should not be defined simply in terms of a specific energy or capacity target, but rather in terms of all system needs—and that should encompass needs for flexible capacity, system inertia, and, lower operating costs. This "total system need" determination should be based on future net load, defined as customer electric usage minus the power supplied by distributed energy resources. It should be based on efficient operation of existing infrastructure and should take into account relevant government policies such as a price on carbon. Duke Energy anticipates that its first year of need for new capacity is 2026, and if coal retirements are advanced to the earliest practicable dates then total need will be approximately 9,300 MW between

[8] John D. Wilson, et al., Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement (2020), https://energyinnovation.org/wp-content/uploads/2020/04/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices.pdf.

[9] John D. Wilson, Resource Insight, Inc., Implementing All-Source Procurement in the Carolinas (2021), attached as Attachment 6.

2026 and 2031. For the purposes of his report, Mr. Wilson adopted the need determination made by Duke, including earliest practicable coal retirements.

Under traditional resource planning, anticipated procurement and economic retirement dates are outputs of IRP modeling, which depends on the forecast cost of new generation. However, forecasts are never perfectly accurate and cost forecasts for renewable resources historically have been particularly inaccurate. Rather than rely on cost forecasts, all-source procurement obtains cost information directly from the market. In addition, if the cost of new generation declines more than anticipated in a forecast, then it may become cost-effective to advance or increase procurement of new generation resources and reduce the dispatch of existing generation resources.

The second step in all-source procurement is soliciting, evaluating, and selecting bids to meet the utility's "total system need". To begin, the utility solicits bids, under the Commission's oversight.[10] Crucially, the request for proposals allows the full range of potential resources—or combinations of resources—available in the market to compete to meet the defined need, at any location in the service territory. Mr. Wilson recommends soliciting bids to meet need from the year of first need in 2026 through 2031, but evaluating and contracting in stages. After all bids have been received, the independent administrator or Duke Energy screens them against minimum compliance criteria and evaluates them using the IRP system planning model, ultimately generating a bid evaluation report that includes alternative portfolios. The Commission then approves or

[10] To reduce structural biases and prevent improper self-dealing, the process should include safeguards such as an independent administrator or monitor and transparency regarding assumptions and analyses. The Commission's Competitive Procurement of Renewable Energy ("CPRE") process includes such safeguards, and provides a good model.

modifies a resource portfolio, after taking public comment and potentially holding a public hearing.

There are a few limited exceptions to the principle that "all" resources participate. For example, some DSM resources such as aggregated third-party DSM and bring-your-own-thermostat ("BYOT") programs may be difficult to incorporate into an all-source procurement. Energy efficiency resources may also not be able to participate, but the development of EE resources should be coordinated. A regular all-source procurement process with contract deliveries eight or nine years in the future could make energy efficiency appear less cost-effective than it really is, because the value of energy efficiency typically is determined by the avoided costs and those deliveries no longer could be avoided. There are a few solutions, but the best would be for Duke Energy to commit in its IRP to all cost-effective energy efficiency.

It may be wise to limit the participation of near-term emerging technologies such as offshore wind, and small modular nuclear reactors that are not economically competitive yet. These resources could be evaluated as generic resources limited to alternative portfolios, until a developer is able to make a fully qualified bid. This will prevent the process from foreclosing these resources entirely when they might become economically viable in the near future, while at the same time not yet choosing a portfolio that includes them. In addition, the utility will continue to plan its investments in developing longer-term emerging technologies such as zero-emission load-following resources ("ZELFR") through the IRP process.

Other resource development activities should be coordinated with all-source procurement, including Duke Energy's Integrated System & Operations Planning (ISOP), which will govern its investments in resources such as transmission, distribution, and voltage optimization programs. It might be necessary to invest in new grid resources in order to integrate generation resources bid into an all-source procurement, or new generation resources could make grid investments unnecessary. The Commission should ensure that Duke Energy evaluates alternative grid investments through ISOP concurrently with the evaluation of generation resource bids in all-source procurement.

All-source procurement is more likely to result in the least-cost mix of demand- and supply-side resources than traditional single-source procurement because it harnesses market dynamics more effectively in three main ways. First, the cost information used in all-source procurement is more accurate because it comes directly from the market at the time of procurement rather than from IRP forecasts. Recent history has shown that the cost of new renewable generation has declined much more than forecast. All-source procurement will capture any such cost decline and select the resources that are cheapest at the time of procurement, rather than locking into one generation technology in a single-source procurement determined by an outdated forecast.

Second, all-source procurement selects the least-cost portfolio of resources that can meet the utility's overall need because it allows different technologies or combinations of technologies to compete to meet the overall need, rather than single solutions to discrete portions of it. This holistic view can find opportunities to meet need more efficiently. For example, one utility that perceived a discrete need to replace 660 MW of coal-burning generation received bids for 58,000 MW of nameplate capacity and ended up cost-effectively contracting generation resources supplying 1,100 MW of firm capacity.

Finally, all-source procurement can help to overcome common biases that tend to result in inefficient procurement. Traditional procurement practices among vertically integrated utilities can suffer from biases toward over-procurement of capacity, self-built generation, and natural gas and other fuel-based generating technologies. By allowing all forms of technology to compete on a level playing field to meet need, all-source procurement avoids these biases.

A shift to all-source procurement would not displace single-source procurements, at least in the near term. As noted, Mr. Wilson recommends using all-source procurement to procure resources beginning in the year of first need in 2026, through 2031. In the interim, there are multiple reasons that the Commission should authorize additional procurement of renewable resources. When it passed H589 the General Assembly explicitly contemplated that the Commission could authorize additional tranches of renewable procurement under the CPRE program based upon a finding of need in the IRP. See N.C. Gen. Stat. § 62-110.8(a). Even in the absence of a specific statutory mandate or other policy directive, or even a capacity need, a competitive solicitation for renewable resources would result in additional fuel-free and zero-carbon resources, reducing fuel costs for the benefit of ratepayers.

The Commission has the authority to require all-source procurement. The Commission must "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina." N.C. Gen. Stat. § 62-110.1(c). As part of its analysis, the Commission also must develop a plan to meet those needs. *Id.* Chapter 62 "require[s] energy planning . . . in a manner to result in the *least cost mix of generation* and demand-reduction measures which is achievable," N.C. Gen. Stat. § 62-2(a)(3a), and the Commission's rules require IRPs to include resources chosen to provide reliable electric utility service *"at least cost* over the planning period," NCUC Rule R8-60(c) (emphases added). For the reasons discussed above, all-source procurement is more likely to lead to least-cost procurement than the status quo. For all of the above reasons, the Commission should require Duke to implement all-source procurement starting in 2026 as part of the Commission's annual plan to meet electricity resource needs in the most cost-effective manner. SACE, et al. recommend that the Commission take the following steps, as detailed fully in Attachment 6: The Commission should identify Duke's total system need beginning in 2026 through 2031, and should require DEC and DEP to revise their 2020 IRPs using all-source procurement for procurements beginning in 2026. The initial all-source procurement RFP should solicit bids to meet total system need for the 2026 to 2031 time period, but DEC and DEP should evaluate, model and contract in stages.

RELIEF REQUESTED

SACE, et al. ask that the Commission review the 2020 DEC and DEP IRPs carefully, consider these comments and those of other intervenors and the Public Staff, find that the 2020 Duke IRPs fail to meet the requirements of state law and decline to accept them as reasonable for planning purposes. Further, SACE, et al., request that the Commission require the Companies to correct any deficiencies identified in light of these comments and those of other intervenors and the Public Staff and file revised IRPs within 60 days of the Commission's final order. After the filing of reply comments, SACE, et al. may request that the Commission convene an evidentiary hearing on any issues in contention regarding the 2020 IRPs and hear expert testimony on those issues.

Respectfully submitted this 1st day of March, 2021.

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CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Partial Initial Comments of Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council as filed today in Docket No. E-100, Sub 165 has been served on all parties of record by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.

This 1st day of March, 2021.

s/ Gudrun Thompson

ENERGY FUTURES GROUP

ATTACHMENT 1
E-100, Sub 165

energyfuturesgroup.com

Review of DEC and DEP Market Potential Studies

Underestimation of Energy Efficiency

and

Demand Side Management

Prepared by:

Dan Mellinger and Jim Grevatt

February 5, 2021

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About the Authors

Energy Futures Group (EFG) is a clean energy consulting firm based in Hinesburg, Vermont and with offices in Boston and New York. EFG specializes in the design, implementation and evaluation of programs and policies to promote investments in energy efficiency, renewable energy, other distributed resources and strategic electrification. EFG staff have worked on these issues on behalf of energy regulators, other government agencies, utilities and advocacy organizations across the United States, Canada, Europe, and China.

Dan Mellinger is a Principal with Energy Futures Group. He specializes in the design, planning and administration of commercial and industrial energy efficiency programs and is a lighting technologies expert. He provides technical consultative services on efficient technology capabilities, market analysis, technology adoption, energy savings potential, industry standards, and training programs. Dan has consulted on hundreds of commercial efficiency projects across many jurisdictions nationwide and has designed and administered industry-leading commercial lighting programs. He received his degree in Electrical Engineering from Michigan State University, is a licensed Professional Engineer, is a Certified Energy Manager, and is Lighting Certified.

Jim Grevatt has 30 years of experience in energy efficiency program planning and operations. At Energy Futures Group Jim has advised regulators, program implementers, and advocates in Florida, Louisiana, West Virginia, Colorado, Nevada, British Columbia, Manitoba, Maryland, Pennsylvania, Delaware, Virginia, New Jersey, Illinois, Iowa, Indiana, Mississippi, North Carolina, South Carolina, California, Vermont, Maine, Kentucky, and New Hampshire, and has provided expert witness testimony in fourteen of those jurisdictions. Jim has hands-on experience with industry-leading approaches to designing and managing energy efficiency programs, including multi-family, low income, residential retrofit, new construction, HVAC, and efficient products programs. His in-depth knowledge of program operations and clear understanding of strategic thinking and planning ensure that programs achieve their desired market impacts. In past leadership roles at Efficiency Vermont, the DCSEU, and Vermont Gas, Jim had overall responsibility both for program design and operations, assuring that program processes were efficient and effective.

Introduction

At the request of the Southern Environmental Law Center, EFG conducted a review of key assumptions employed by Duke Energy ("Duke" or "Company") and Nexant in developing the Duke Energy North Carolina and South Carolina EE and DSM Market Potential Studies ("MPS") dated June 2020. EFG also compared the potential winter peak capacity savings identified in the MPS to the results of the December 2020 Duke Energy Winter Peak Analysis ("WPA") that was prepared for Duke by Tierra Resource Consultants in partnership with Dunsky Energy Consulting and Proctor Engineering Group.

Accurate estimates of the full scope of potential energy efficiency ("EE") and demand-side management ("DSM") savings are critical for the development of the Company's Integrated Resource Plans ("IRP") to ensure that costly infrastructure and capacity investments are not made unnecessarily when lower-cost EE and DSM alternatives are available. In Duke's IRP, "EE-based demand and energy savings are treated as a reduction to the load forecast, which also serves to reduce the associated need to build new supply-side generation, transmission and distribution facilities."[1] The IRP views DSM programs "as resource options that can be dispatched to meet system capacity needs during periods of peak demand."[2]

In reviewing both the MPS and WPA, EFG relied on data that were available in the public reports and did not conduct a detailed analysis of the underlying data. Nevertheless, this review revealed numerous instances where arbitrary limitations were made in the scope of the MPS that result in significant underestimations of potential EE and DSM savings. The Company itself says as much regarding potential winter peak savings, when it states, "preliminary results from [the WPA] show promise for additional winter peak demand savings that could move the Company closer to the high energy efficiency and demand response sensitivity identified in the IRP." [3]

[1] Duke Energy Carolinas 2020 Integrated Resource Plan, p.35.

[2] Duke Energy Carolinas 2020 Integrated Resource Plan, p.35.

[3] Duke Energy Carolinas 2020 Integrated Resource Plan, p.36.

Principal Observations – EE Potential

Omissions

1. **Emerging Technologies**
   The Nexant studies for DEC and DEP indicate that the MPS only considers "existing technology and market trends as observed with currently available data and does not speculate on the potential impact of unknown, emerging technologies that are not yet market ready." [4] This failure to account for emerging technology results in a conservative long-term forecast of EE potential. The seriousness of this omission increases the further out in time the estimates of savings potential go insofar as new technologies or systems are constantly being developed. For example, nearly half of the efficiency savings in the Northwest Power and Conservation Council's Draft Seventh Power Plan were from efficiency measures not included in the Council's sixth plan published just five years prior.[5] The portfolios offered today by DEC, DEP, and other utilities include numerous high-impact measures that would have been considered emerging technologies or non-existing 10-15 years ago, such as LED lighting, heat pump water heaters, smart thermostats, and networked lighting controls. Over the next 10-15 years, the marketplace will continue to evolve, and new products and technologies will inevitably be introduced. Speaking to the importance of emerging technology, the American Council for an Energy Efficient Economy ("ACEEE") states the following:

   > Assumptions about emerging technologies (ETs) can have a noticeable impact on potential results, particularly for those studies that consider long-term savings potential (i.e., ten years out or more). Many studies we reviewed include savings from ETs, but only a half-dozen or so are transparent about the measures they assume to be emerging. Where savings potential from ETs is provided, however, the impacts are considerable. Cadmus' 2012 study for the Iowa Utility Association, for example, finds that ETs could increase electric

[4] Nexant North Carolina Market Potential Study, p.10; Nexant South Carolina Market Potential Study, p.10.

[5] *The Next Quantum Leap in Efficiency: 30 Percent Electric Savings in Ten Years*, The Regulatory Assistance Project, February 2016 (http://www.raponline.org/wp-content/uploads/2016/05/rap-efg-neme-grevatt-30percentefficiency-2016-feb-1.pdf).

market potential (i.e., maximum achievable potential) by up to 3%, or 0.3% additional achievable savings annually over the ten-year study period (Cadmus 2012). KEMA's 2010 study for Xcel Energy Colorado finds that economic potential increases by 24% when ETs are included. Of these, 13% could be achieved through programs over an 11-year period (KEMA 2010). Clearly the savings potential for ETs is substantial enough that it should not be ignored.[6]

2. Omitted Measures

Even within the realm of known technology, the Nexant potential studies omitted measures that would have contributed to higher energy savings potential. Figure 1 below lists nearly two dozen technologies that are known today and offered by numerous energy efficiency programs in other jurisdictions.

[6] *Cracking the TEAPOT: Technical, Economic, and Achievable Potential Studies*, August 2014 (https://www.aceee.org/research-report/u1407)

Figure 1: Omitted Measures

Sector	Measures
Residential	LED decorative and directional lamps Pool covers CEE tier 2 refrigerators
Commercial	Networked lighting controls LED parking lot lighting LED directional lamps Evaporator fan motor controls Variable refrigerant flow (VRF) Dedicated outdoor air system (DOAS) Air-source heat pumps Variable speed air compressor Dual enthalpy economizer for existing buildings Data center hot/cold aisle configuration
Industrial	Strategic energy management Process improvement Compressed air leak survey & repair Compressed air no-loss drains Chiller plant optimization Advanced rooftop control

The impact that these measures would have had on the MPS is difficult to quantify, but undeniably their omission results in an underestimation. Several of the measures listed in the table have proven to offer significant energy savings potential due to large load reductions, widespread applicability, or both. For example, the U.S. Department of Energy's High Impact Technology program identified significant savings potential from advanced rooftop unit controls (56%) and variable refrigerant flow (34%).[7] Other potential studies have identified networked/integrated lighting controls, strategic energy management, and evaporator fan motor controls among the top contributing

[7] https://www.energy.gov/eere/buildings/high-impact-technology-deployment-pathways

measures to achievable potential.[8]

3. **New Customer Engagement Strategies and Program Designs**

   The Nexant MPS relies on customer engagement strategies and program designs that are currently employed by DEC and DEP and makes no effort to estimate the potential from new or enhanced strategies. An attempt was made to model an "enhanced" level of savings, but this was only done by introducing higher incentives (75% of incremental cost) and assumed higher adoption based on a customer's willingness to participate. Nexant states that "[w]hile program design and optimization is outside the scope of this MPS, Nexant's enhanced scenario describes the expected market response to higher incentives that reduce participant costs for EE and DSM." [9] Yet new customer engagement strategies and program designs can reach new customers and change their willingness to participate for a variety of reasons. For example, a customer may be more willing to participate if on-bill financing were offered for investments in energy efficiency projects. In another example, midstream programs that focus on technologies beyond commercial lighting, such as residential/commercial HVAC and commercial kitchen equipment, can reach far more customers than downstream programs, often with lower administration costs. Financing and midstream programs both overcome a key obstacle to customer participation: the upfront capital investment. Additional examples of strategies and designs omitted by the MPS include energy efficiency as a service (EEaS) and strategic energy management (SEM). Had Nexant accounted for any of these or other engagement strategies and program designs, it is likely that more aggressive adoption curves would be possible resulting in higher levels of savings.

Study Design

1. **End-use Disaggregation**

   The disaggregation of the DEC and DEP loads into end-uses is an important step in the development of a market potential study. The end-use shares of the sector loads are

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[8] Minnesota Energy Efficiency Potential Study, 2020 (https://mn.gov/commerce-stat/pdfs/mn-energy-efficiency-potential-study.pdf); Michigan Lower Peninsula Electric Energy Efficiency Potential Study, 2017 (https://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf); Commonwealth Edison Energy Efficiency Potential Study, 2020 (https://ilsag.s3.amazonaws.com/ComEd-2021-2030-Potential-Study-Final-Report-rev1_Aug-2020.pdf)

[9] Nexant North Carolina Market Potential Study, p.74; Nexant South Carolina Market Potential Study, p.74.

used as a basis for calculating energy savings. For example, the percentage savings from efficient chillers is applied to the portion of the sector load that has been allocated to air conditioning to estimate the potential savings that could be achieved from that measure. Therefore, ensuring that the load has been disaggregated properly into relevant end-uses is a critical step. Nexant relied on data sources from Duke to perform this disaggregation, with secondary data from the Energy Information Administration (EIA) Residential End Use Consumption Survey (RECS), Commercial Building Energy Consumption Survey (CBECS), and Manufacturers' Energy Consumption Survey (MECS). However, two areas of concern stand out in Nexant's analysis:

a. Nexant assumes approximately 27% of the commercial load falls into the "miscellaneous" end-use for both DEC and DEP.[10] The EIA CBECS, meanwhile, shows only 17% of the load in an "Other" category for the South Atlantic census division.[11] This is an important consideration since few measures in the MPS are associated with the miscellaneous end-use, which means that very little energy savings potential will be derived from 27% of the DEC/DEP commercial load using Nexant's assumption. Furthermore, with the miscellaneous end-use representing an outsized portion of the load, other end-uses will be underrepresented, and savings from those measures will be conservatively low.
b. In the residential sector, the miscellaneous category is again notably higher than what the EIA data suggest. Nexant assumes 21% and 14% miscellaneous for DEC and DEP, [12] respectively, compared to 11% estimated by RECS.[13] Furthermore, Nexant's estimate for water heating and clothes drying end uses are approximately half as much as estimated by EIA, meaning high-growth potential measures such as heat pump water heaters and heat pump

[10] Nexant North Carolina Market Potential Study, pp. 24-25; Nexant South Carolina Market Potential Study, pp. 24-25.

[11] EIA CBECS 2012. Table E5, South Atlantic census division, indicates an "Other" end-use electricity consumption of 48 billion kWh out of the total electricity consumption of 287 billion kWh.

[12] Nexant North Carolina Market Potential Study, pp. 23-25; Nexant South Carolina Market Potential Study, pp. 23-25.

[13] EIA RECS 2015. Table CE5.1b, South Atlantic census division, indicates an "Other" end-use electricity consumption of 34.7 billion kWh. Table CE4.4, South Atlantic division, indicates the total electricity consumption of 316 billion kWh.

dryers will have significantly understated savings.

2. **Future Improvements in Efficiency and Cost**
The MPS also fails to account for increasing measure savings due to technology improvement and decreasing measure and program costs driven by economies of scale. Many technologies have well established track records of energy improvement over time, such as LED lighting and heat pumps, and it is well understood that new technologies will decrease in cost as they continue to develop market acceptance. The Nexant modeling of measures assumes a static efficiency level and cost. Some measures are modeled with multiple levels of efficiency, such as various SEER levels for air conditioning, but these measures compete against each other and their saturation shares remain fixed throughout the study. For other measures such as LED lighting and heat pump water heaters, the study has no mechanism to account for higher levels of efficiency and lower anticipated costs. The multiple implications of these shortcomings are: (1) these measures will underrepresent the savings potential; (2) some measures will fail the economic screen due to lower savings and higher cost; and (3) the levelized cost of a measure will be unreasonably high and will lead to inaccurate modeling in the IRP.

3. **Achievable Potential**
The Nexant MPS includes two levels of achievable potential, described as follows:
    - Base scenario – aligns with existing program portfolio, and includes existing EE programs and measures currently offered by DEC or DEP.
    - Enhanced scenario – includes the base scenario, but with increased program incentives designed to attract new customers into the market for EE technology and program participation.

Unfortunately, this approach fails to reasonably account for known EE technologies that could be offered using typical incentive rates. The "base scenario" is constrained to measures currently offered in the existing program portfolio, and therefore energy efficiency measures that are known today but not offered by Duke, such as those listed above in Figure 1, are excluded. As a result, the long-term potential will be significantly underestimated since there is no mechanism to allow the portfolio to evolve over time. While some of these measures are included in the "enhanced scenario" they are associated with an incentive that is doubled (subject to a maximum of 75% of incremental cost), which likely artificially inflates the cost required to induce customers to install them.

Nexant also calculates the achievable potential based on historic participation rates. As previously discussed, participation rates can be influenced by a variety of factors, including incentives and marketing, which can be adjusted to drive different participation rates through program designs and strategies. The participation rates currently experienced by the programs should not be assumed to be an upper bound, as this constrains potential by assuming that program delivery improvements would have no effect on participation and savings.

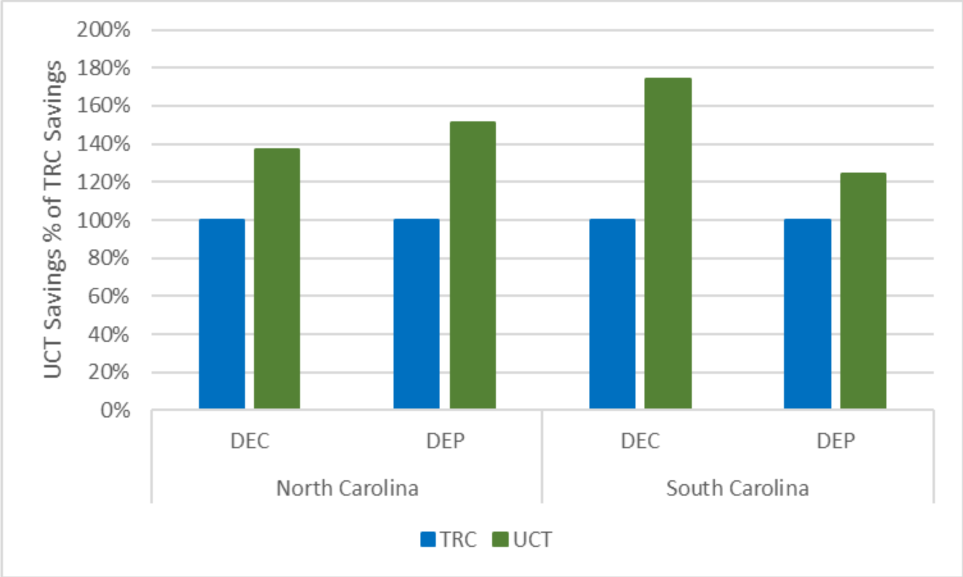
4. Economic Screening

The market potential studies use the Total Resource Cost ("TRC") test as currently approved by regulators for economic screening, which, as discussed by ACEEE, is asymmetrical because it "counts a number of categories of costs (e.g., the full incremental measure cost to customers) without their attendant benefits (e.g., other fuel or water savings, or health benefits)."[14] The MPS uses this asymmetric TRC even though use of the Utility Cost Test ("UCT") as the primary cost-effectiveness test in North and South Carolina was pending in mechanism review proceedings with regulators at the time the MPS was developed, and has since been approved.[15] Nexant performed a sensitivity analysis for economic potential using the UCT and found significantly higher economic savings potential, summarized for the residential sector in Figure 2 below:

[14] Gold, R., C. Cohn, A. Hoffmeister, and M. Molina. 2020. How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy, Cost, and Greenhouse Gas Impacts. Washington, DC: American Council for an Energy-Efficient Economy, p. 25. https://www.aceee.org/research-report/u2007

[15] The UCT has since been approved as the primary cost-effectiveness test in both states. See Docket No. 2013-298 –E, Order No. 2021-32, https://dms.psc.sc.gov/Attachments/Order/9f6b5eea-227f-42f7-9326-622c28be349c (DEC); Docket No. 2015-163-E, Order No. 2021-33, https://dms.psc.sc.gov/Attachments/Order/fd6a5654-593f-4ebd-a2a7-8419bab8ee51 (DEP).

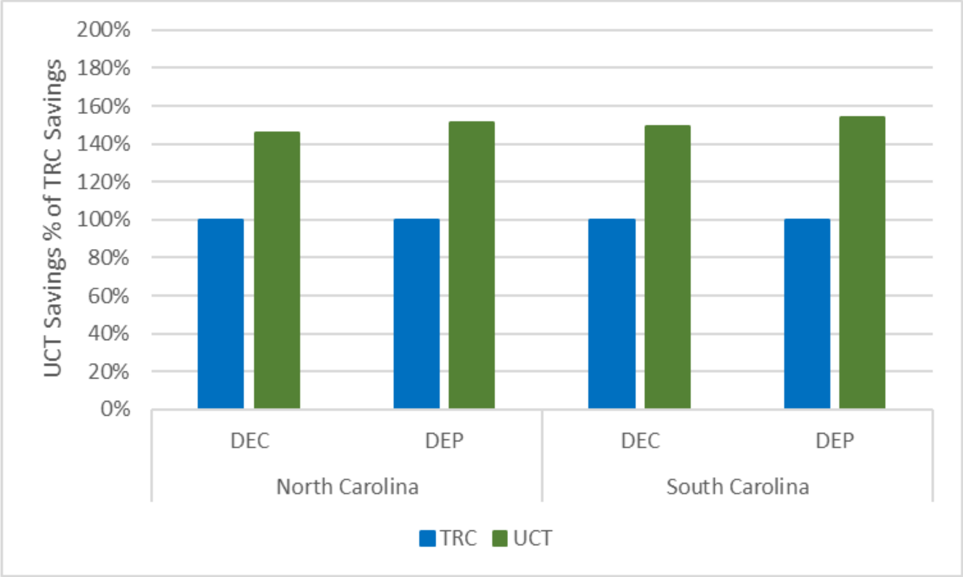
Figure 2: Residential UCT Economic Savings vs. TRC[16]



Commercial cost-effective savings were also considerably greater under the UCT, illustrated in Figure 3 below:

[16] Nexant North Carolina Market Potential Study, p.72; Nexant South Carolina Market Potential Study, p.72.

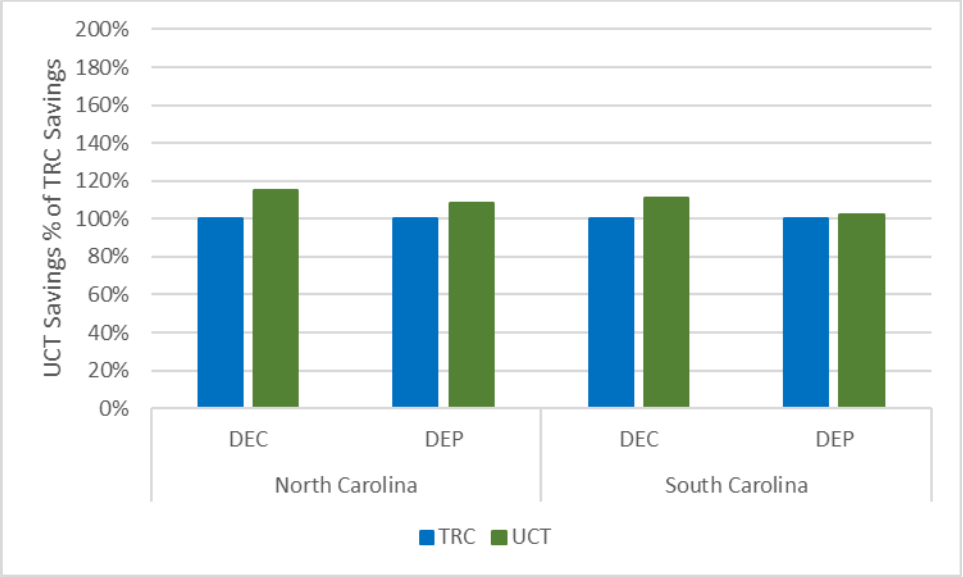
Figure 3: Commercial UCT Economic Savings vs. TRC[17]



And, while the gap between UCT savings and TRC savings was not as great for industrial measures, UCT savings were nevertheless still greater, as shown in Figure 4:

[17] Nexant North Carolina Market Potential Study, p.72; Nexant South Carolina Market Potential Study, p.72.

Figure 4: Industrial UCT Economic Savings vs. TRC[18]



Based on these findings, and the adoption of the UCT as a primary cost-effectiveness test, the results of the market potential study based on the TRC must be viewed as overly conservative and not reflective of the true economic potential. Refreshing the MPS analysis using UCT savings rather than TRC would be one step that Duke could take to more realistically assess EE savings potential in the Carolinas.

Study Results

1. **Low Achievable Potential Relative to Other Jurisdictions**
   The MPS estimates that Duke can expect only a relatively low level of achievable savings, as illustrated below in Table 1:

[18] Nexant North Carolina Market Potential Study, p.72; Nexant South Carolina Market Potential Study, p.72.

Table 1: Average Incremental Annual Savings as a % of Sales, 5-yr Sum of Annuals[19]

North Carolina		South Carolina	
DEC	DEP	DEC	DEP
0.88%	0.94%	0.91%	0.89%

For all of the reasons described above, EFG concludes that the MPS is highly likely to significantly understate Duke's EE savings potential in the coming years. This finding is consistent with observations made by ACEEE, which reports that its "meta-analysis of potential studies from around the country in states or utilities similar to Dominion, Duke Energy Progress and Duke Energy Carolinas in their retail prices…found achievable average annual savings as a percentage of baseline of 1.2% (with achievable maximum annual savings of 1.6%). A number are also vertically integrated utilities, such as Entergy New Orleans, Puget Sound Energy, NV Energy, and Minnesota utilities, and the sample includes large utilities like Duke, such as ComEd, Ameren Illinois, and Entergy Louisiana, and some smaller utilities like Dominion in North Carolina, such as Idaho Power and some of the Minnesota utilities included in their statewide potential study." [20]

2. **Unreasonable Reliance on Residential Behavioral Programs**
The residential energy efficiency potential is heavily reliant on savings from behavioral programs, as outlined in the following table:

Table 2: Behavior Savings % of Residential 5-Year Cumulative Potential, Base Scenario[21]

North Carolina		South Carolina	
DEC	DEP	DEC	DEP
75%	78%	75%	73%

Behavior savings have very short persistence – a measure life of just one year – and must be "renewed" each year through repeated customer treatment. As a result,

[19] Nexant North Carolina Market Potential Study, pp.3-4; Nexant South Carolina Market Potential Study, pp.3-4.

[20] Gold, R., C. Cohn, A. Hoffmeister, and M. Molina. 2020. How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy, Cost, and Greenhouse Gas Impacts. Washington, DC: American Council for an Energy-Efficient Economy, p. 26. https://www.aceee.org/research-report/u2007

[21] Nexant North Carolina Market Potential Study, Figure 7-5 and Figure 7-14; Nexant South Carolina Market Potential Study, Figure 7-5 and Figure 7-14.

behavior savings do not accumulate/persist. Due to the short measure life, the levelized cost of behavior savings will tend to be more expensive than other long-lived measures. Accordingly, with such a heavy reliance on behavior the levelized cost of the residential sector as calculated by Nexant is twice as expensive as the non-residential sector. There are many factors that can lead to a more expensive levelized cost for the residential sector, but an excessive reliance on behavior exacerbates the issue. As the savings from residential lighting diminish due to market maturation and the effect of federal standards, programs have an opportunity to backfill the void with non-lighting equipment-based measures such as HVAC and heat pump water heaters. Unfortunately, the MPS takes the easy, but short-sighted approach, by relying too heavily on behavioral programs, thus depriving customers of substantive opportunities to manage their energy costs.

The long-term effect of this strategy is plainly obvious when comparing the cumulative (persisting) energy savings to the sum of annual savings. When not counting the savings from expired measures, the 25-year cumulative energy savings potential is a mere 1.26-1.35% of sales while the sum of annual energy savings appears much more significant, as shown in Table 3. Unfortunately, the sum of annual MWh figure is a mirage since a large portion of the savings persist for only one year. As a point of comparison, the 2019 Electric DSM Market Potential Study for Vectren Energy of Indiana identified behavior savings potential at 20% of the residential sector[22], and the 25-year cumulative energy savings potential is accordingly much more significant at 21.9% of sales[23].

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[22] GDS Associates 2020-2025 Integrated Electric DSM Market Potential Study & Action Plan, Table 4-6 on p. 29. https://www.vectren.com/assets/downloads/rates/in-south-action-plan.pdf

[23] GDS Associates 2020-2025 Integrated Electric DSM Market Potential Study & Action Plan, Figure 4-1 on p. 25, realistic achievable potential (RAP). https://www.vectren.com/assets/downloads/rates/in-south-action-plan.pdf

Table 3: 25-year Potential, Base Scenario[24]

	North Carolina		South Carolina	
	DEC	DEP	DEC	DEP
Cumulative MWh (% of Load)	1.31%	1.26%	1.35%	1.26%
Sum of Annual MWh (% of Load)	17.34%	19.13%	18.01%	17.87%

Another way to highlight this issue is to consider the percentage of savings that persist after just 5 years.[25] According to Nexant's analysis, the behavior-heavy residential sector would have only 24-25% persisting savings after 5 years, while the non-residential sector would have 99% persisting savings as shown below in Figure 5. Using Vectren Indiana as a point of comparison again, a much more significant 72% of the residential sector energy savings persist after 5 years.[26]

[24] Nexant North Carolina Market Potential Study, Table 7-6 and Table 7-14; Nexant South Carolina Market Potential Study, Table 7-7 and Table 7-14.

[25] Calculated as the 5-year cumulative energy savings divided by the 5-year sum of annual energy savings.

[26] GDS Associates 2020-2025 Integrated Electric DSM Market Potential Study & Action Plan. The 5-year sum of annual savings is 221,243 MWh based on Table 4-6 on p. 29. The 5-year cumulative savings is 159,025 based on Table 4-7 on p. 30. https://www.vectren.com/assets/downloads/rates/in-south-action-plan.pdf

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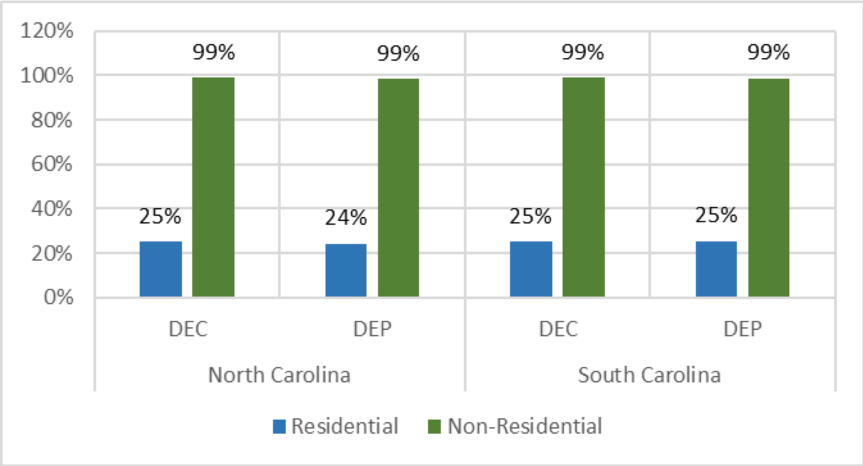
Figure 5: % of Annual Savings that Persist after 5 Years [27]



3. **Levelized Cost**

   The market potential studies calculate and present levelized costs by sector for DEC and DEP. These costs, according to Nexant, are "presented from the TRC perspective as the sum of incremental measure costs and program admin costs divided by the discounted sum of lifetime energy savings. Program potential costs include both incremental measure costs and program delivery and administrative costs."[28] Since the levelized costs include the participant cost, these values will be misleading (and overly expensive) in comparison to other resource options being modeled and considered in the IRP. For this reason, the levelized costs as presented in the Nexant studies should not be used as an input to the Integrated Resource Plan. Instead, EFG recommends that the levelized costs for energy efficiency be recalculated from the UCT perspective as the sum of program incentives and admin costs divided by the discounted sum of lifetime energy savings. And importantly, when accounting for lifetime energy savings, the calculation must include the benefit of persisting savings that extend beyond the horizon of the

[27] Nexant North Carolina Market Potential Study, Table 7-8 (DEC), Table 7-11 (DEC), Table 7-16 (DEP), Table 7-19 (DEP); Nexant South Carolina Market Potential Study, Table 7-8 (DEC), Table 7-11 (DEC), Table 7-16 (DEP), Table 7-19 (DEP)

[28] Nexant North Carolina Market Potential Study, footnote 4, p.88; Nexant South Carolina Market Potential Study, footnote 4, p.88.

market potential study. For example, the savings from a measure with a 10-year life installed in 2044 (the last year of the MPS) should include the persisting savings from years 2045-2053. Without access to the underlying data, EFG cannot determine if Nexant performed the levelized cost calculation in this manner.

Capacity Savings in the MPS and Winter Peak Analysis

In the MPS, Nexant states that "DSM opportunities were analyzed…to determine the amount of summer and winter peak capacity that could be reduced through DSM initiatives."[29] In its analysis "Nexant and Duke Energy worked together to determine which DSM products and services were included in the MPS"[30] but only chose to include direct load control ("DLC"), emergency load response, economic load response, and base interruptible DSM in its analysis.[31] Importantly, the MPS "excluded DSM programs that explicitly target behavior (i.e., they are not automated or dispatchable)."[32] Non-dispatchable measures can be equally effective at minimizing peak load constraints, and some of them are indeed automated, but they take the form of preventative measures rather than the actively managed dispatchable measures included in the MPS. Examples of non-dispatchable DSM measures omitted from the MPS include time-of-use rates, real time pricing, critical peak pricing, peak time rebates, permanent load shifting, thermal storage, and battery storage. Nexant says further that its analysis of residential and small commercial and industrial ("C&I") DSM opportunities was "limited by the loads that can be controlled remotely at scale"[33] and that "all end uses are considered for large C&I." [34] Further, in the MPS "Nexant incorporated th[e] opt-out rate into the model by reducing the non-residential sales estimates by the appropriate percentage for each service territory and applying the applicable energy efficiency technologies and market adoption rates to the remaining sales forecast."[35] In other words, the MPS assumed that there were no options to

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[29] Nexant North Carolina Market Potential Study, p.4; Nexant South Carolina Market Potential Study, p.5.

[30] Nexant North Carolina Market Potential Study, p.36; Nexant South Carolina Market Potential Study, p.36.

[31] Nexant North Carolina Market Potential Study, p.36; Nexant South Carolina Market Potential Study, p.36.

[32] Nexant North Carolina Market Potential Study, p.48; Nexant South Carolina Market Potential Study, p.48.

[33] Nexant North Carolina Market Potential Study, p.40; Nexant South Carolina Market Potential Study, p.40.

[34] Nexant North Carolina Market Potential Study, p.40; Nexant South Carolina Market Potential Study, p.40.

[35] Nexant North Carolina Market Potential Study, p.34; Nexant South Carolina Market Potential Study, p.34.

achieve DSM reductions for the many C&I customers that have opted out of the EE/DSM programs.

Unfortunately, the limitations that were imposed in the MPS DSM analysis result in a significant underestimation of DSM potential, particularly in winter, where the need is growing. This is made starkly clear in the more thorough Winter Peak Analysis ("WPA"), which reflects Duke's recognition that "meeting its clean energy commitments requires finding innovative approaches for addressing winter peak capacity needs with clean energy resources" which is "becoming a greater need than summer peak as net loads after solar are growing faster for winter needs than summer."[36] That winter peak capacity requirements are expected to continue to be larger than summer peak requirements is discussed in the WPA[37] and illustrated in the IRP.[38]

Because the focus of the Company's current DSM programs has been on reducing summer peaks, the underlying reliance on current programs in the MPS results in very low estimates for winter peak savings potential. The WPA illustrates the gap in the Company's current DSM portfolio used in the MPS when it states that "[b]ased on HP [heat pump] saturation data available from the 2019 RASS, we estimate that approximately 15% of all HP units are currently enrolled in a residential DSM program, the vast majority of which control only cooling (AC) operations…. This analysis estimates that approximately 1.4M customers with HPs are not participating in a DSM program."[39] Yet the WPA also found that "Residential sector programs are key to achieve significant winter demand reduction potentials." [40]

The WPA included analysis of the opportunity for Duke to use both the mechanical, dispatchable solutions such as those addressed in the MPS, but also included an assessment of how different rate structures could be used to manage winter peaks, including how rate structures could be used to mitigate winter peak even for those C&I customers who have opted

[36] Duke Energy Winter Peak Targeted DSM Plan Final Report 2020.12.23, p. 8 of 101.

[37] See, e.g., Duke Energy Winter Peak Analysis and Solution Set Final Report 2020.12.23, p. 11 of 107.

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

[39] Duke Energy Winter Peak Analysis and Solution Set Final Report 2020.12.23, p. 36 of 107.

[40] Duke Energy Winter Peak Targeted DSM Plan Final Report 2020.12.23, p. 95 of 101.

out of the EE/DSM programs. The critical role that rate solutions could play in mitigating winter peak is made crystal clear in the WPA findings, where, for example, in the "Mid Scenario" for DEC and DEP "rate solutions (residential and C&I) and BYOT now collectively account for over 85% of the DSM potential."[41] Overall, the WPA "Max" scenario identifies nearly twice the winter peak potential that is identified in the MPS for DEC and DEP "Base" scenarios and roughly 70% more winter peak potential than the MPS "Enhanced" scenario for DEC and 77% more than for DEP. Importantly, the WPA states "[f]or the C&I market, this study estimates rate and mechanical potential separately and shows the impact mechanical solutions and rates not considered in the MPS and are therefore incremental to that study. For the residential sector, the potential in this study is also incremental to the MPS."[42] The comparisons provided in the WPA are reproduced here as Table 4 and Table 5.

Table 4: Reproduced WPA Comparison with MPS Winter Peak Savings[43]

	DEC - 2041 Max Scenario	MPS - DEC (Base - 2041)	MPS - DEC (Enhanced - 2041)
Potential Total (MW)	834	403	488
C&I	Rates: 120 Mechanical: 51	38	69
Residential	Rates: 481 Mechanical: 182	365	419

[41] Duke Energy Winter Peak Demand Reduction Potential Assessment Final Report 2020.12.23, p. 17.

[42] Duke Energy Winter Peak Demand Reduction Potential Assessment Final Report 2020.12.23, p. 22.

[43] Duke Energy Winter Peak Demand Reduction Potential Assessment Final Report 2020.12.23, Table 10: Achievable Potential Comparison - Max Scenario and MPS Enhanced scenario (DEC), p. 22. Note that in both cases the projected savings are incremental to DSM savings already achieved by Duke.

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Table 5: Reproduced WPA Comparison with MPS Winter Peak Savings[44]

	DEP - 2041 Max Scenario	MPS - DEP (Base - 2041)	MPS - DEP (Enhanced - 2041)
Potential Total (MW)	544	273	307
C&I	Rates: 53	3	5
	Mechanical: 36		
Residential	Rates: 306	270	302
	Mechanical: 149		

The WPA concludes that its "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" and notes that:

> …the MPS looked at only mechanical technology solutions, 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 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, <u>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.</u>[45]

[44] Duke Energy Winter Peak Demand Reduction Potential Assessment Final Report 2020.12.23, Table 11: Achievable Potential Comparison - Max Scenario and MPS Enhanced scenario (DEP), p. 22. Note that in both cases the projected savings are incremental to DSM savings already achieved by Duke.

[45] Duke Energy Winter Peak Targeted DSM Plan Final Report 2020.12.23, p.96, underline added.

Conclusions

It is clear to the EFG reviewers that applying the kinds of "innovative approaches" that led to a vastly greater estimate of winter peak savings potential in the WPA compared with the MPS would similarly benefit the underwhelming estimate of EE savings potential that was identified by Nexant. The constraints that were applied in the MPS artificially limit a true estimate of EE savings potential for Duke, which will distort the results of the IRP and may lead to unnecessary investments in costly infrastructure when less expensive EE and DSM/rates alternatives are available that could benefit customers by reducing system costs while simultaneously providing significant energy bill reductions through reduced usage.

ATTACHMENT 2 appears to have been marked confidential by its authors, however the document was produced in a supplemental response to Public Staff Data Request 5-6 in which the document was not designated as confidential.

Attachment 2
E-100, Sub 165

DUKE ENERGY
Winter Peak Analysis and Solution Set

December 2020

DUKE ENERGY

Winter Peak Analysis and Solution Set

December 2020

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Winter Peak Analysis and Solution Set Overview

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

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

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

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

The report includes 7 sections:

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

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

1. Summary of Findings

Peak Demand Overview

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

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

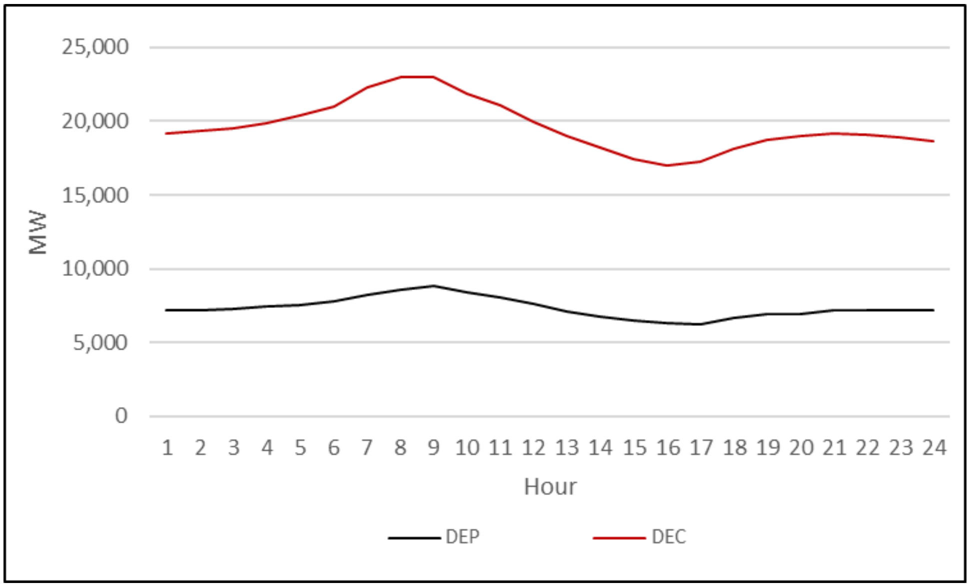


Figure 2 shows the aggregated DEC and DEP load profiles for the residential, small and medium C&I, and large C&I market sectors for the study peak day. The load profiles are overlaid on one another to illustrate the relative magnitude of each market segment indicating that the residential winter morning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

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

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

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

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

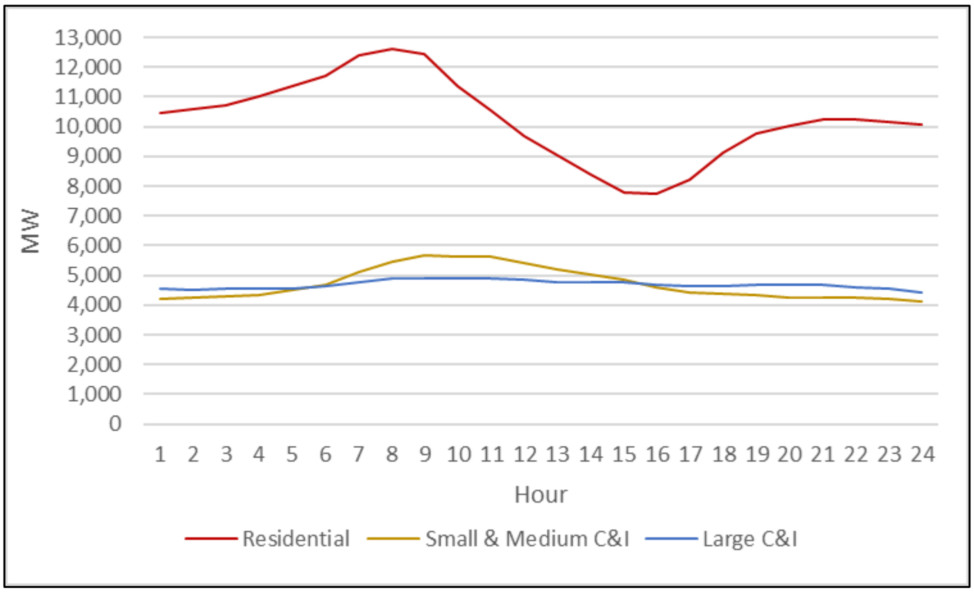
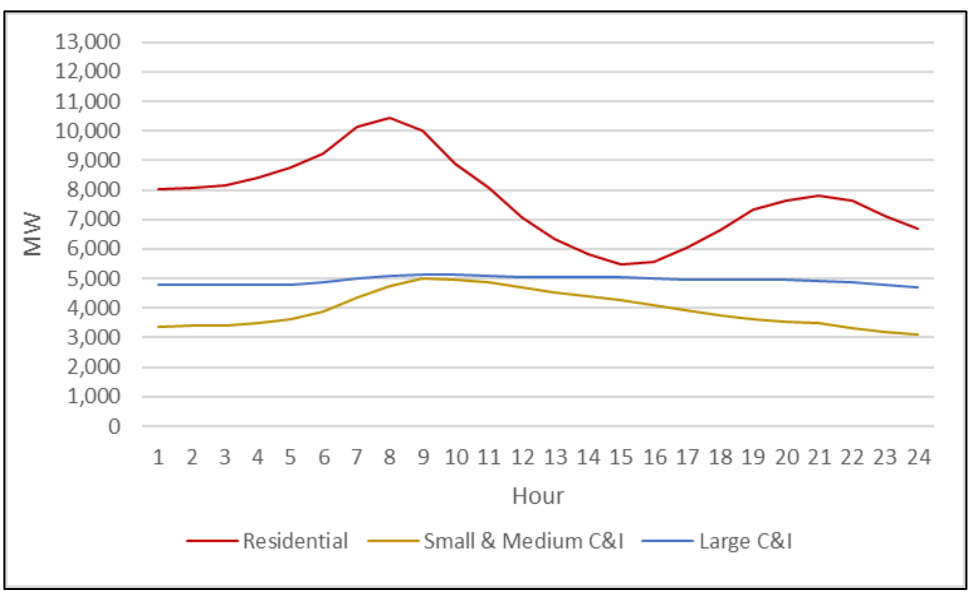


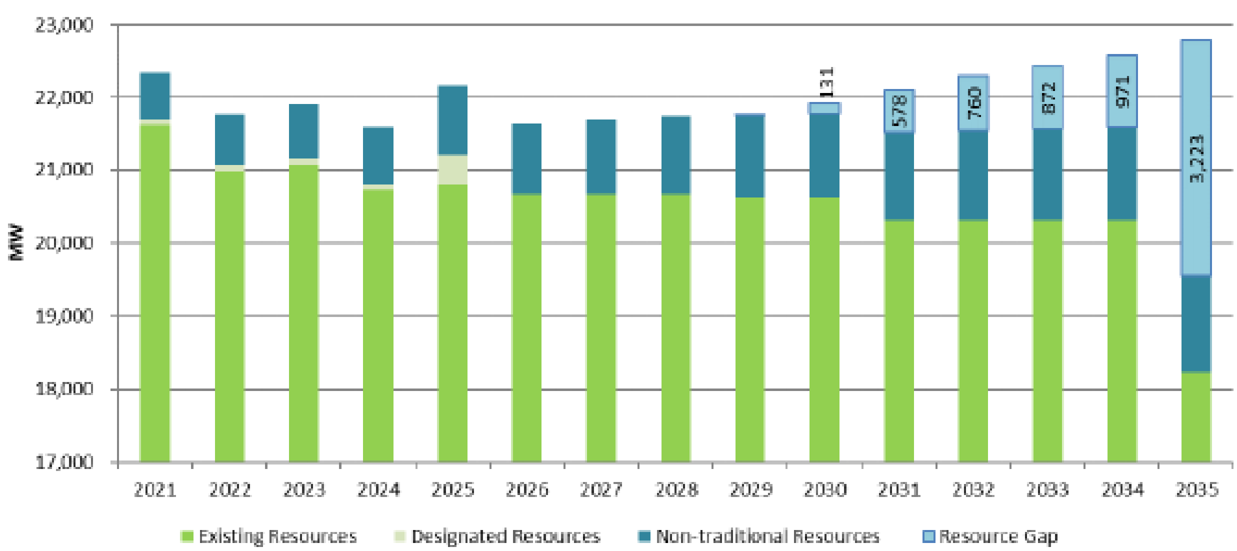
Figure 3. Overlay of Demand Profile by Market Segment - Average Winter Peak Day



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

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

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



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

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

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

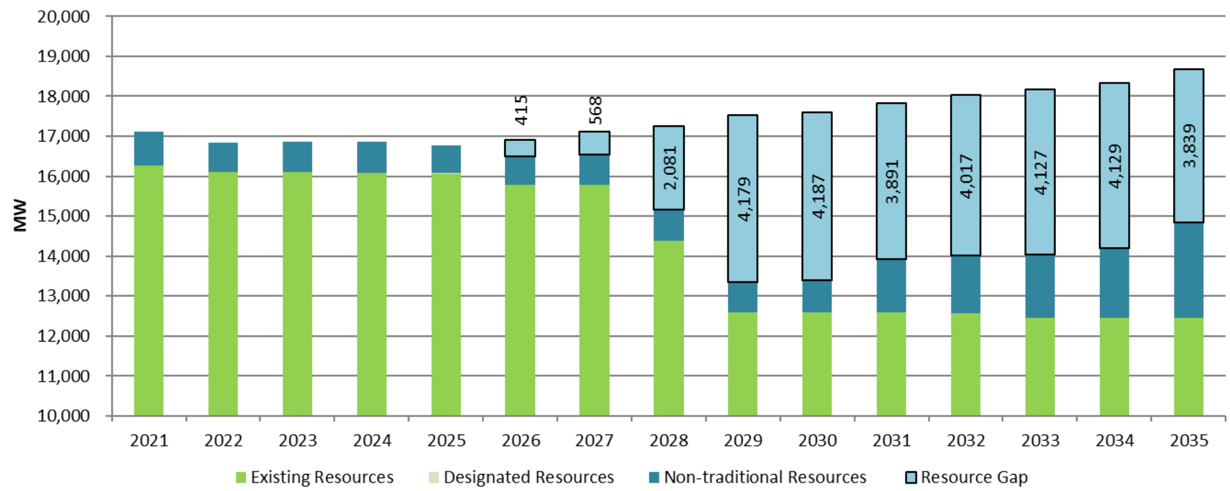
[5] Duke Energy Progress 2020 Integrated Resource Plan. Table 5-A. DEP Base with Carbon Policy Total Renewables

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

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

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

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



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

Current DSM Capacity

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

Table 1. Seasonal System DSM Capacity by Sector

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

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

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

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

Table 2. DSM Capacity by Funding Source

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

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

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

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

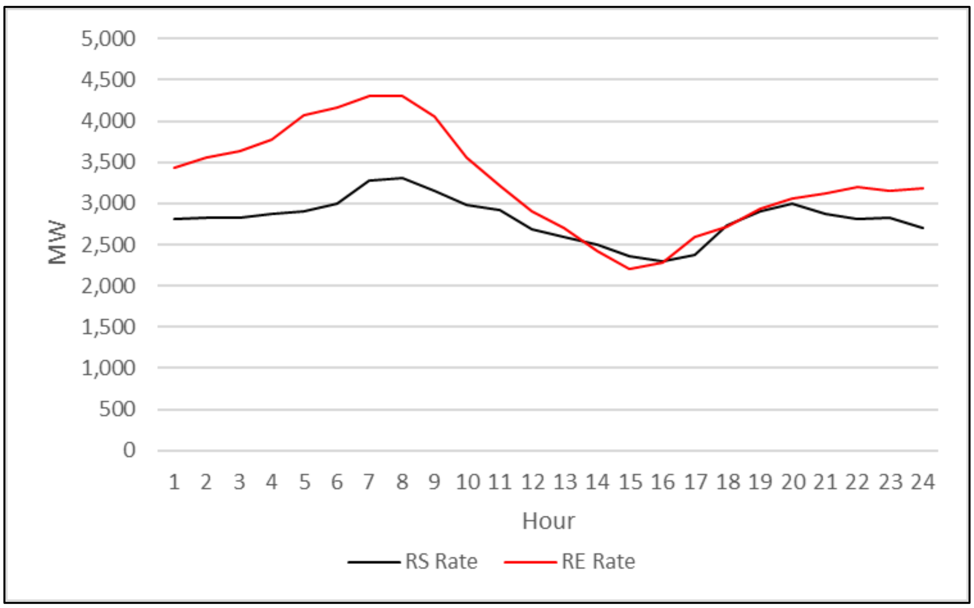
[11] For example, the MPS forecasts the industrial sector to decrease by 6% in NC and 11% in SC by 2044.

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

Residential Market and Solutions

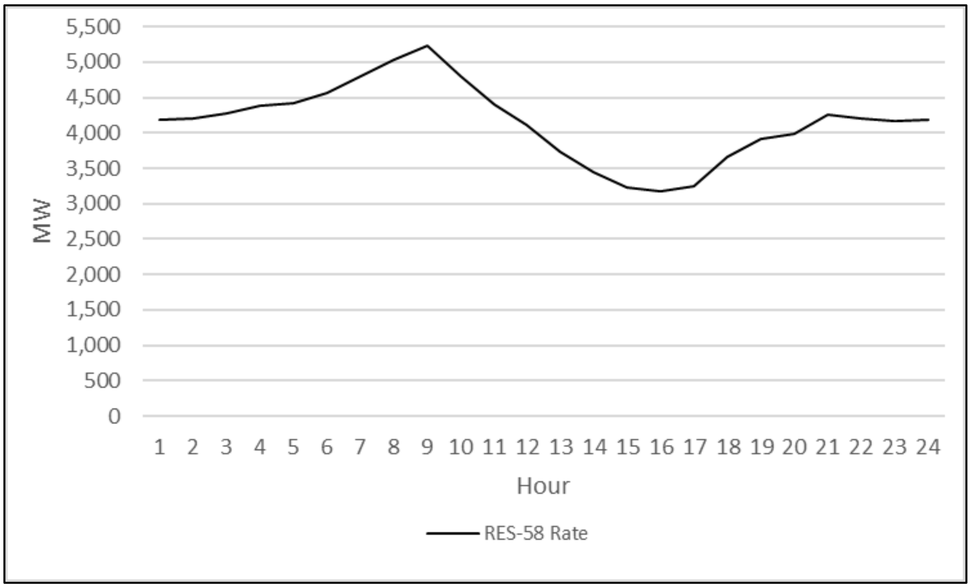
We analyzed various residential market characteristics, appliance saturation data, rates and load profiles for the residential market and concur with past conclusions that the residential winter morning peak demand is driven primarily by electric space heating, with some contribution for electric water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

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



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

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

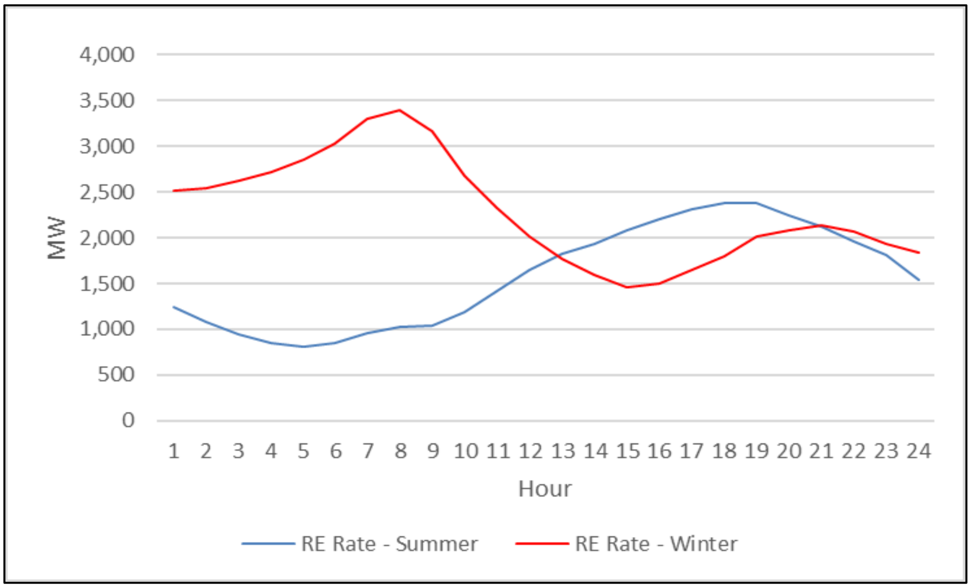


To gain a sense of the magnitude of the electric heating load and types space heating systems that drive peak demand, we also looked at the DEC all-electric 'RE' rate during summer and winter peaks, as presented in Figure 6 showing a difference between summer and winter average peak of 2,500 MW. Because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

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

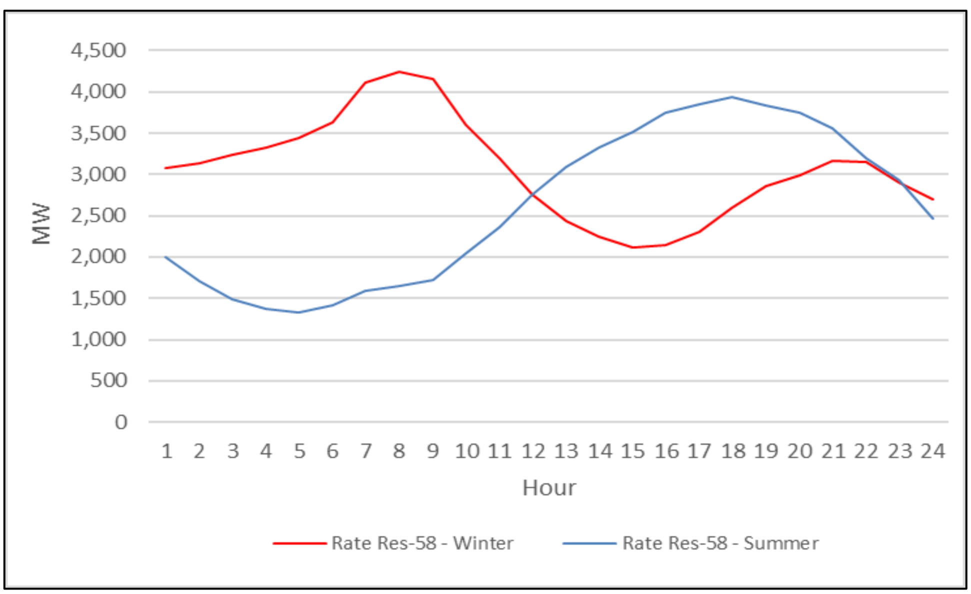
[12] Hot water energy use is generally consistent throughout the year because water usage patterns and groundwater temperature are generally consistent.

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



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

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



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

Figure 10. Single Family Peak Load Profile – Medium User

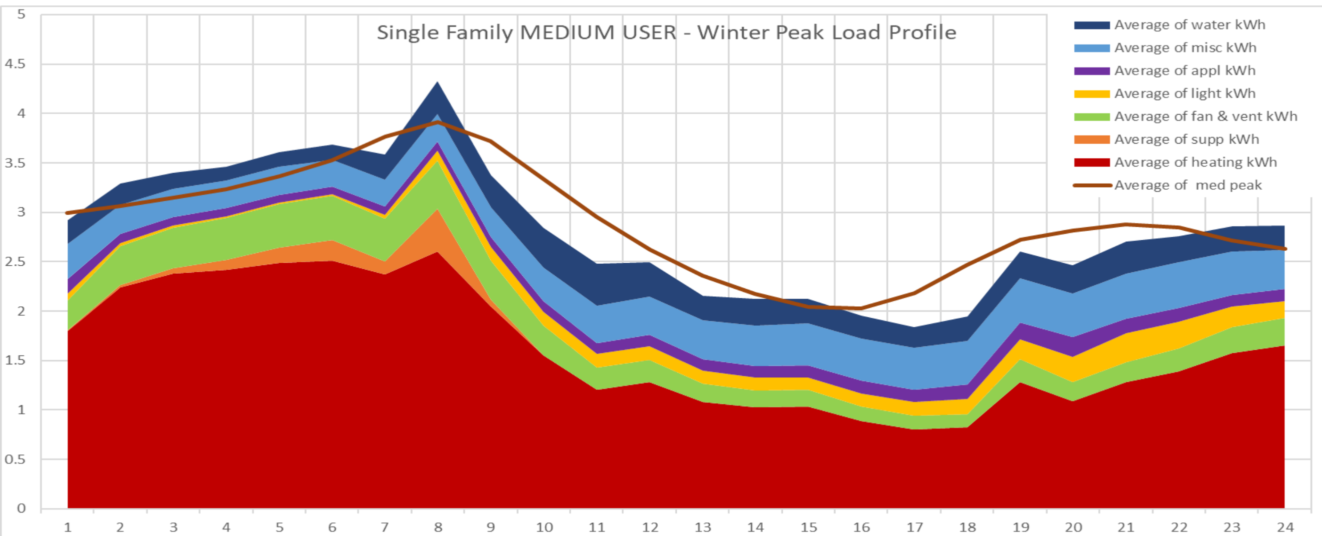
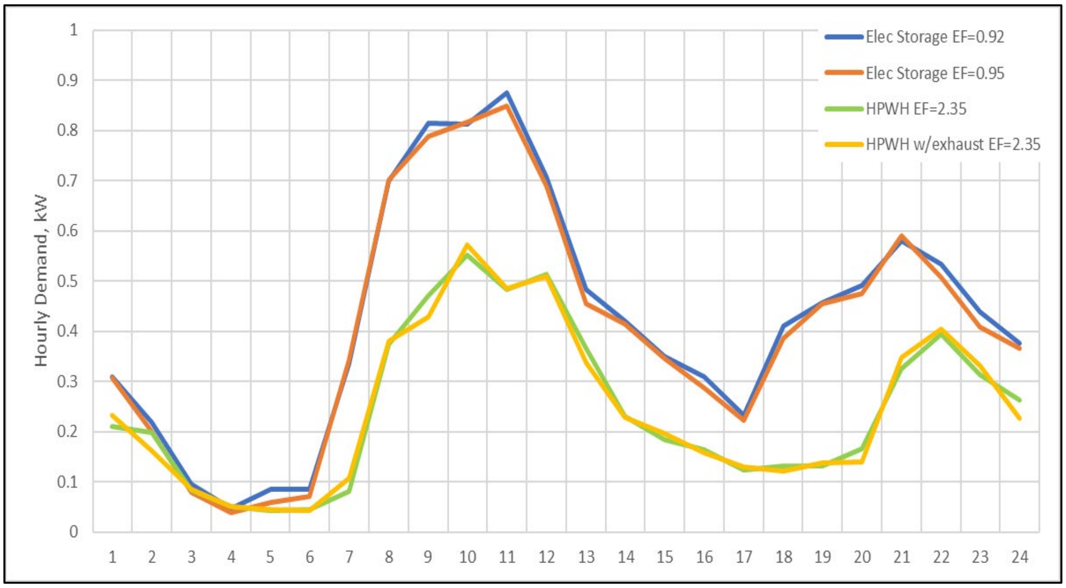


Figure 9 is the modelling output for electric hot water heaters (HWH) showing that electric resistance water heaters require about 0.8 kW per unit during morning peak hours. Duke's 2019 RASS indicates 71% of dwellings use electric HWH, and we estimate this represents about 2.5 million installed resistance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

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

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

Figure 11. Modelled Electric Water Heater Load Profiles



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

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

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

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

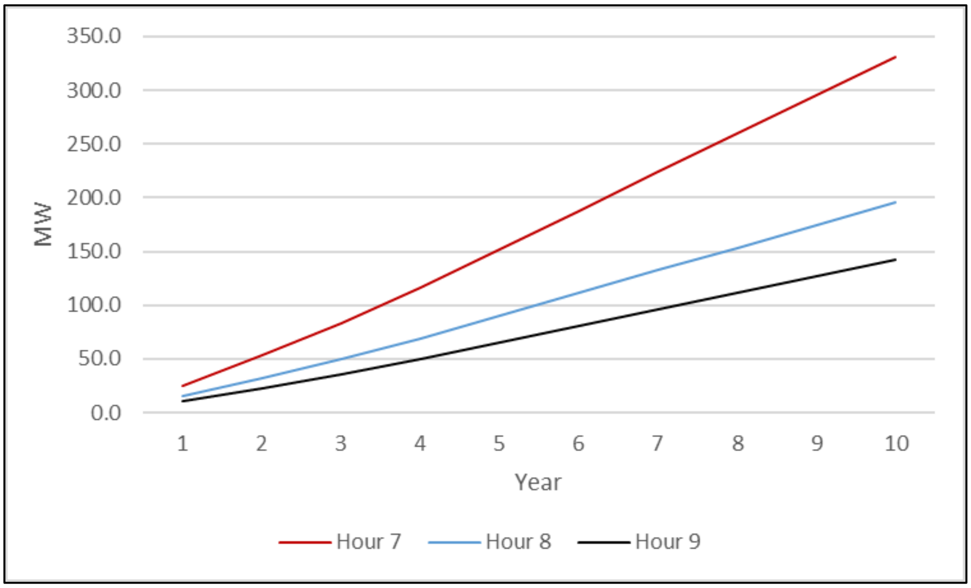
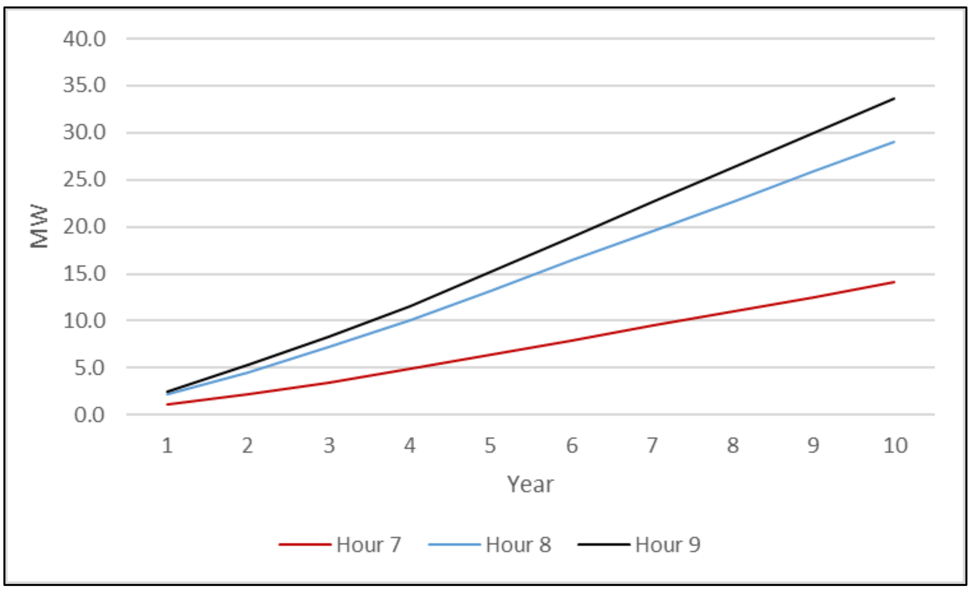


Figure 13. 10-Year Hot Water Heating Savings Forecast by Hour



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

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

C&I Market and Solutions

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

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

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

Small and Medium C&I

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

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

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

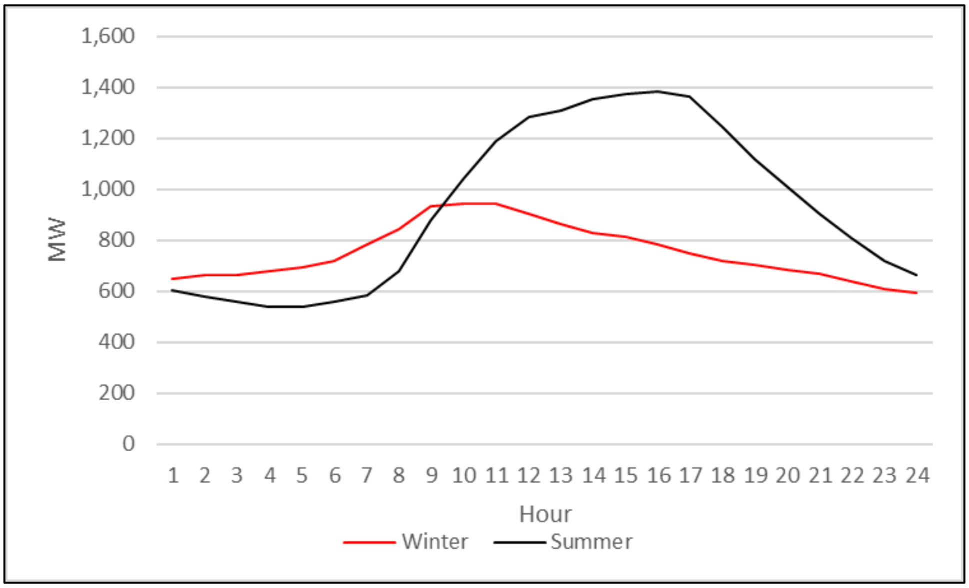
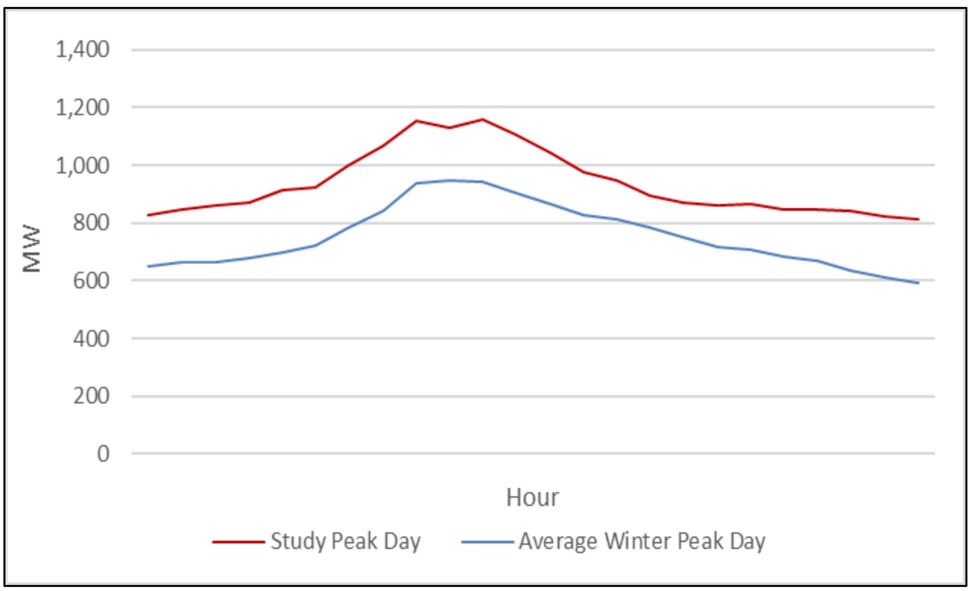


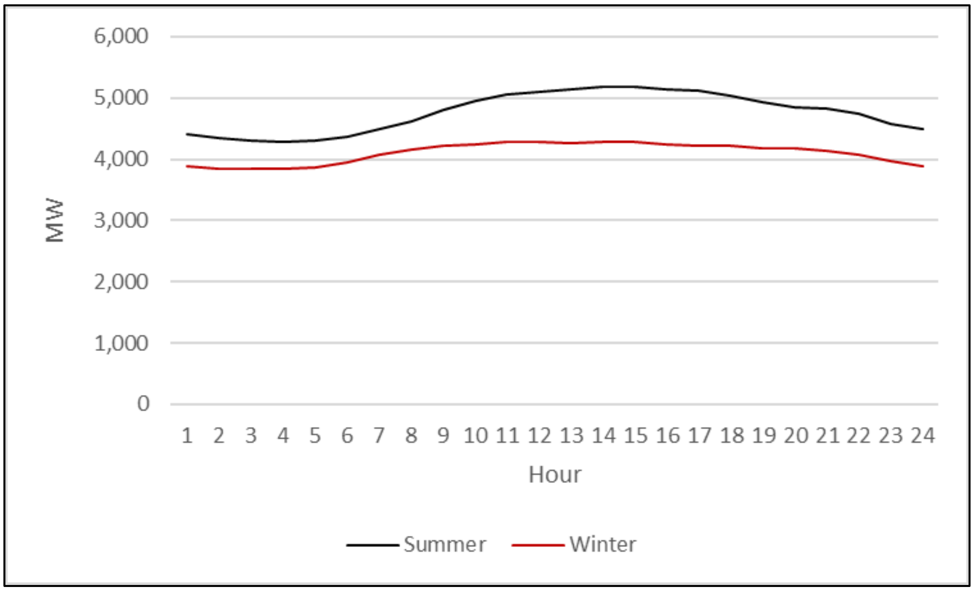
Figure 15. DEC 2018 SGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



Large C&I

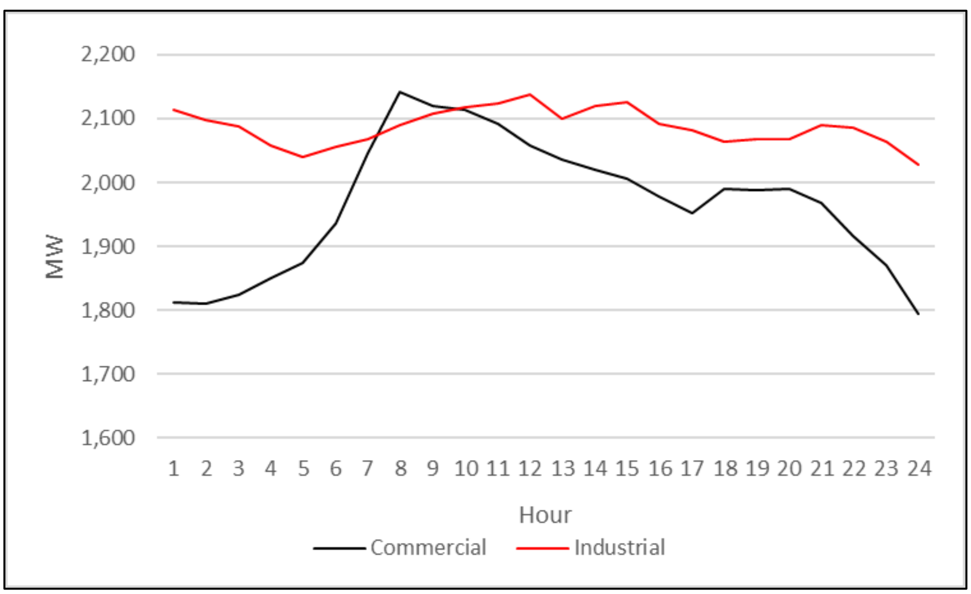
We reviewed the optional TOU rates offered to DEC customers, and the RTP rate offered to DEP customers and Figure 14 shows the demand prolife for the DEC optional C&I TOU rate during the 6 winter and 4 summer events we analyzed. At the aggregate rate level, this profile is generally flat every day, with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

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



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

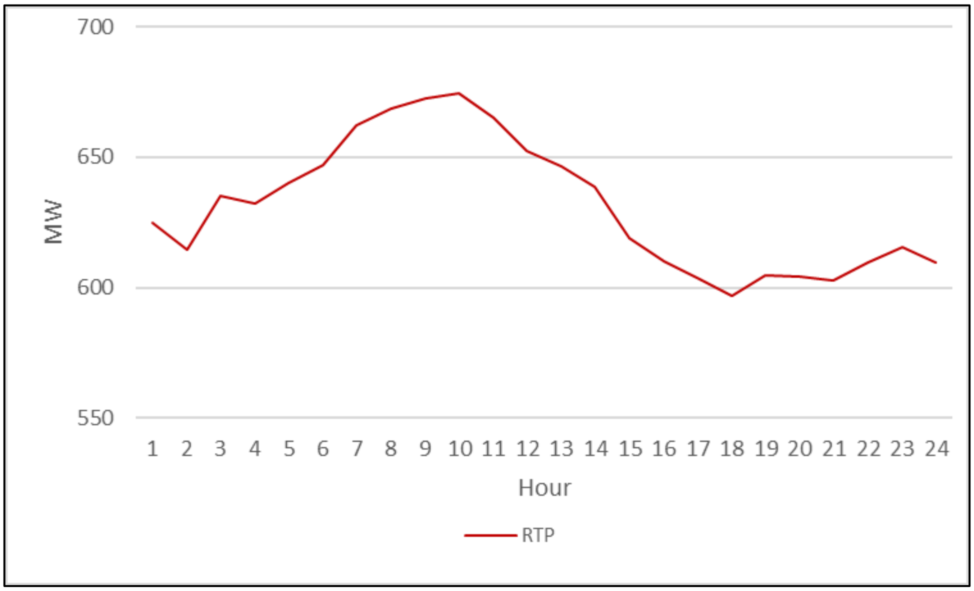
Figure 17. DEC C&I Optional TOU Rate Demand by Segment – Study Peak Day



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

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

Figure 18. DEP RTP Rate Demand – Study Peak Day

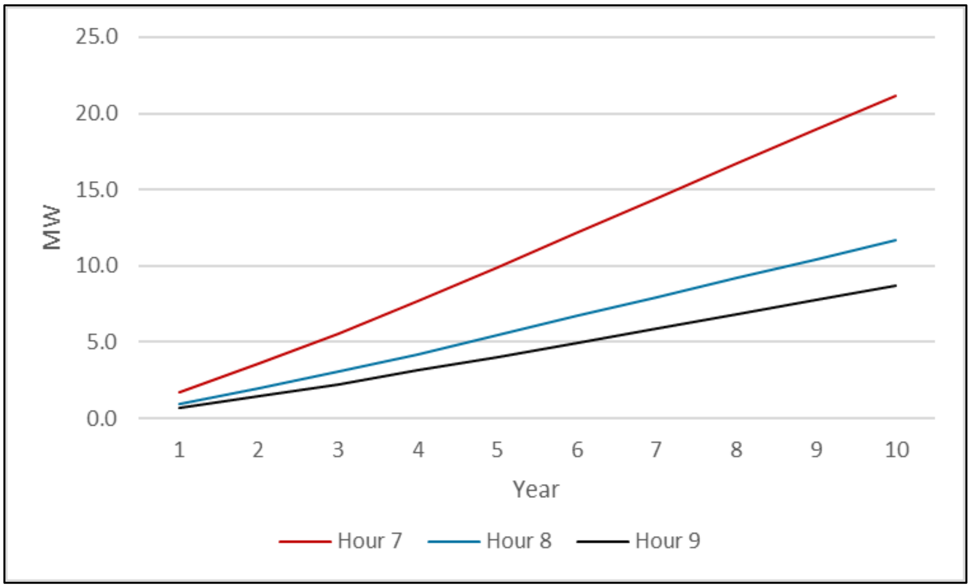


Based on the preceding analysis, the proposed C&I solution set targets demand related to winter morning electric space heating and other building systems and includes the following:

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

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

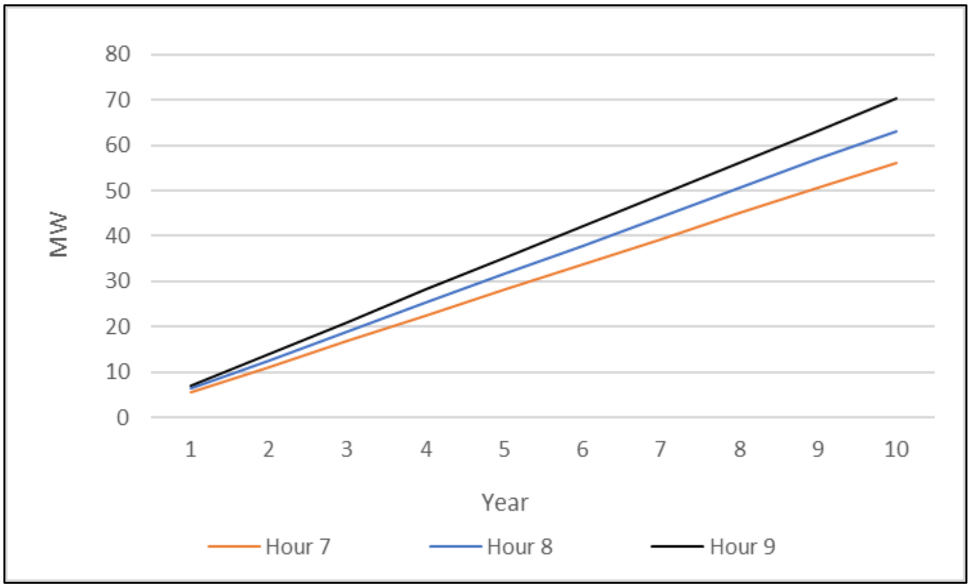
Figure 19. 10-Year Small Commercial Thermostat Solution Savings Forecast by Hour



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

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

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



2. Winter Peak Demand Overview

System Peak

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

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

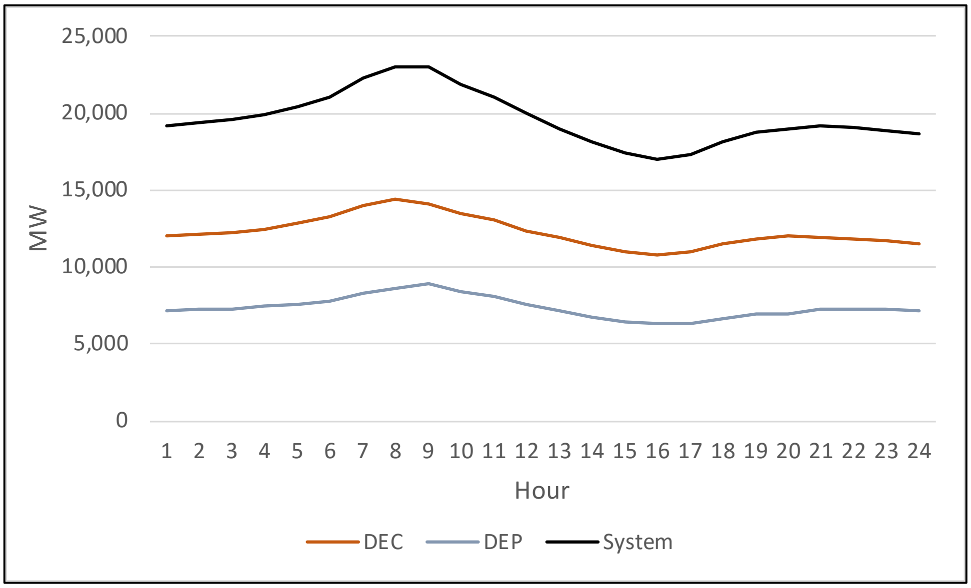
Table 3. 2018 Utility Peak Event by Season

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

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

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

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



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

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

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

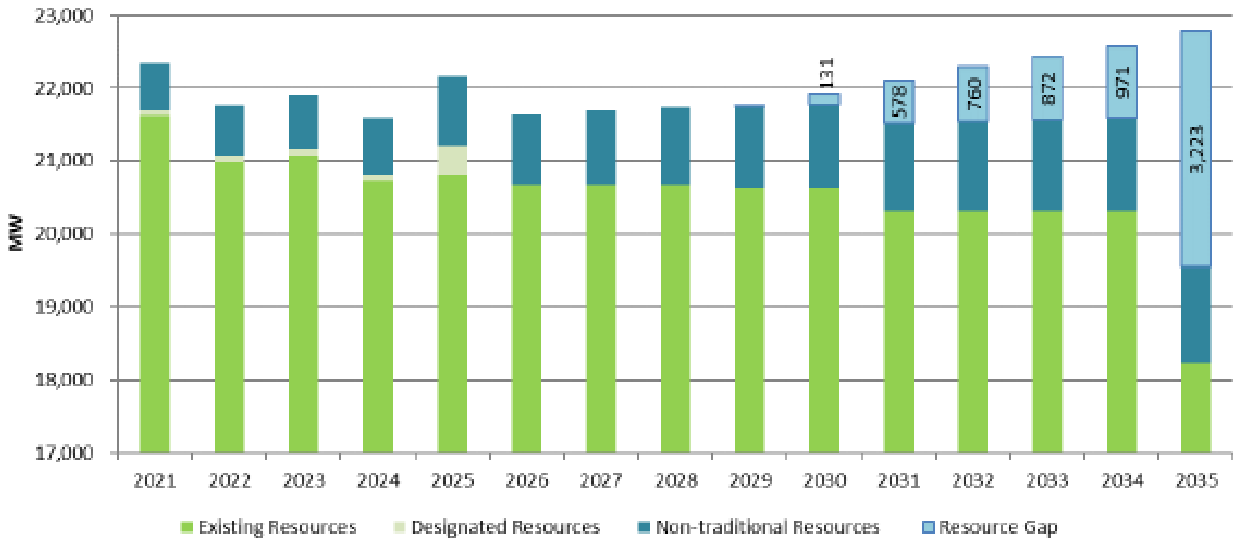


Figure 23. DEP Base Case with Carbon Policy Load Resource Balance (Winter)

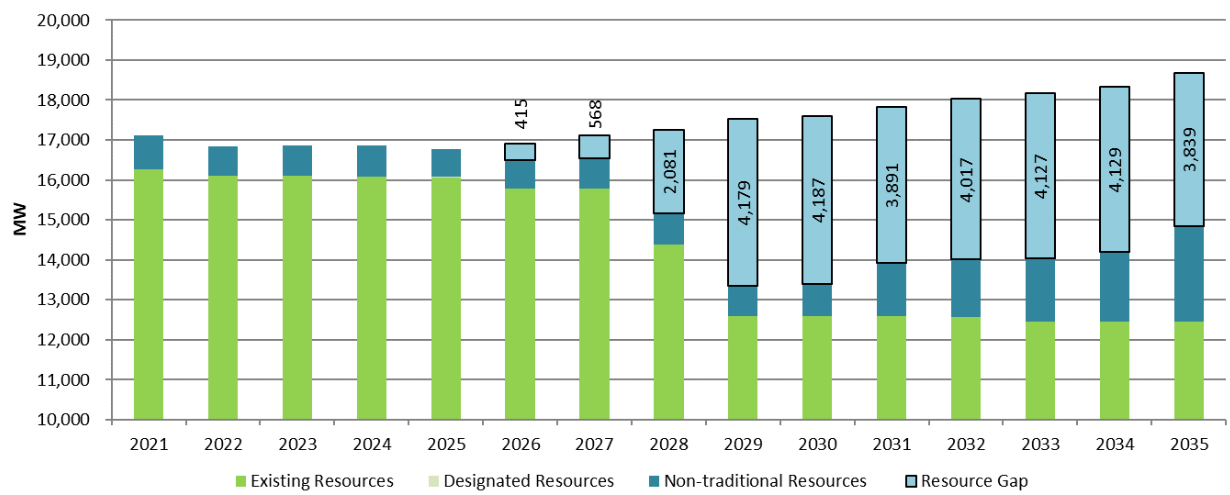


Figure 20 shows demand overlaid individually for each market sector on the study peak day, indicating that residential demand at hour 8 accounted for approximately 12,600 MW (54% of system peak), small to medium C&I sector accounted for 5,600 MW (25% of system), and large C&I accounted for 4,800 MW (21%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

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

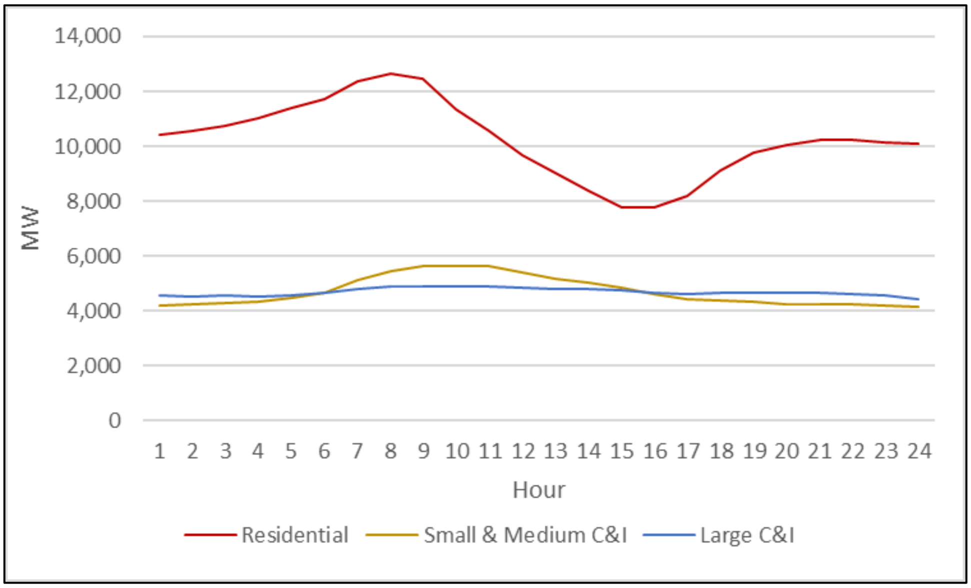


Table 4 shows the 3-hour peak event window for each rate class highlighted in green for the study peak day. This distribution of 3-hour events was common in all peak events reviewed and followed this sequence:

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

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

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

Rate Class Peak Summary

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

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

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

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

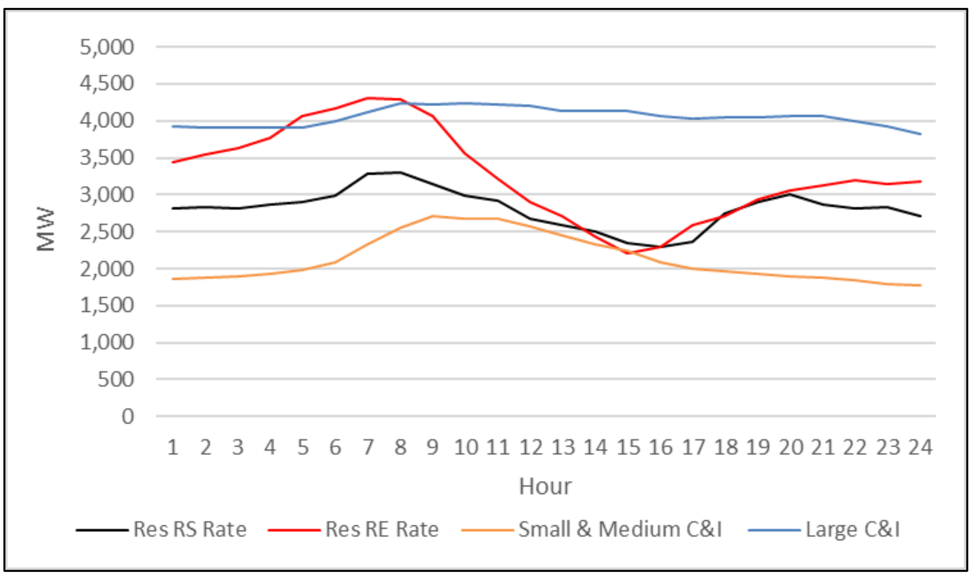


Figure 26. DEC 2018 Peak Demand Profile by Rate Class - Average Winter Day

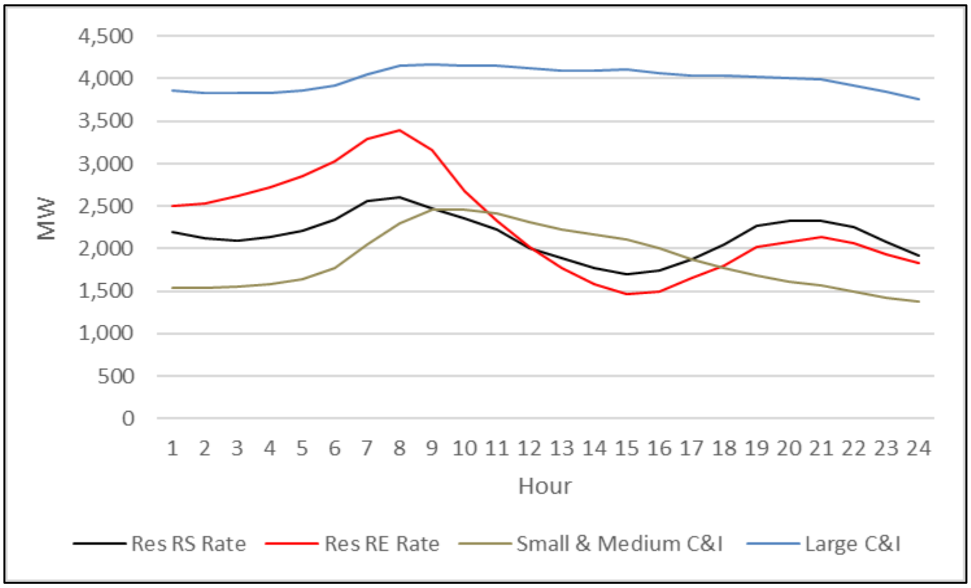


Figure 23 shows the load profile for various DEP rates and rate classes for our study peak day, including:

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

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

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

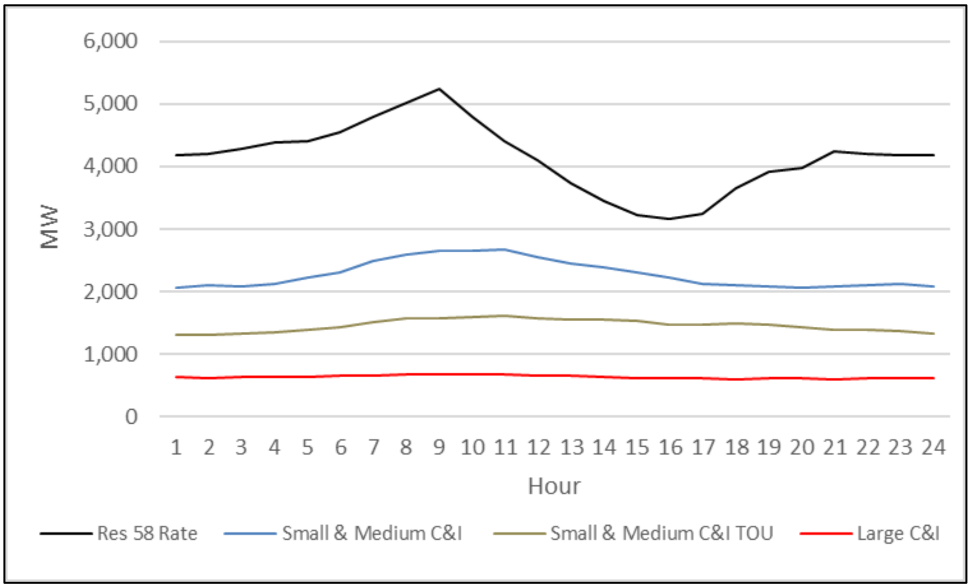
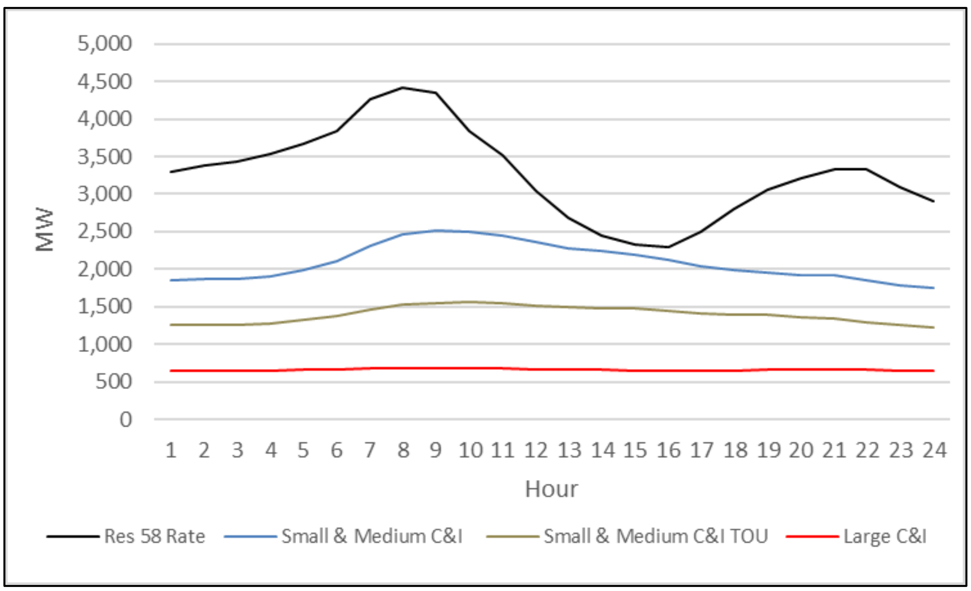


Figure 28. DEP 2018 Demand Profile by Rate Class - Average Winter Peak Day



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

3. Current DSM Capacity

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

Table 5. DSM Capacity Snapshot

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

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

Table 6. Seasonal System DSM Capacity by Sector

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

Table 7. Seasonal System DSM Capacity by Utility and Sector

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

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

Table 8. DSM Capacity by Cost Recovery Source

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

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

Residential DSM Capacity

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

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

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

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

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

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

The following are several observations regarding residential DSM capacity:

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

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

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

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

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

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

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

Table 10. Residential DSM Population Participation

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

Small & Medium C&I DSM Capacity

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

Table 11. Small Business EE/DR Program Snapshot

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

Large C&I DSM Capacity

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

Table 12. Large C&I DSM Snapshot

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

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

Legacy Programs

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

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

DSM Rider Programs

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Summary of DSM Rider Opt-out

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

Table 16. DEP Opt-out by Rate Class

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

Table 17. Summary of Opt-out by Utility

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

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

4. Residential Market and Solutions

Rate Definitions

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

Table 18. Residential Rates Summary

<table>
<tr><th>System</th><th>Schedule</th><th>Tier Type</th><th>On Peak</th><th>Winter</th><th>Study Peak Day MW</th><th>% Utility Sector Demand</th><th>% System Load</th></tr>
<tr><td rowspan="3">DEC</td><td>RS</td><td>None</td><td>None</td><td>Nov – June</td><td>3,306</td><td>43%</td><td>25.4%</td></tr>
<tr><td>RE</td><td>Tiered kWh</td><td>None</td><td>Nov – June</td><td>4,297</td><td>56%</td><td>33.0%</td></tr>
<tr><td>RT</td><td>On/Off kWh</td><td>7:00 a – 12:00 n</td><td>Oct – May</td><td>15</td><td>0.2%</td><td>0.1%</td></tr>
<tr><td rowspan="3">DEP</td><td>RES-58</td><td>None</td><td>None</td><td>Nov – June</td><td>5,237</td><td>97%</td><td>40.3%</td></tr>
<tr><td>R-TOU-58</td><td>On/Part/Off kWh</td><td>6:00 a - 9:00 a</td><td>Sept - Mar</td><td rowspan="2">146</td><td rowspan="2">3%</td><td rowspan="2">1.1%</td></tr>
<tr><td>R-TOUD-58</td><td>On/Off kWh
On kW</td><td>6:00 a - 1:00 p</td><td>Sept - Mar</td></tr>
</table>

Peak Load Profile

DEC

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

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

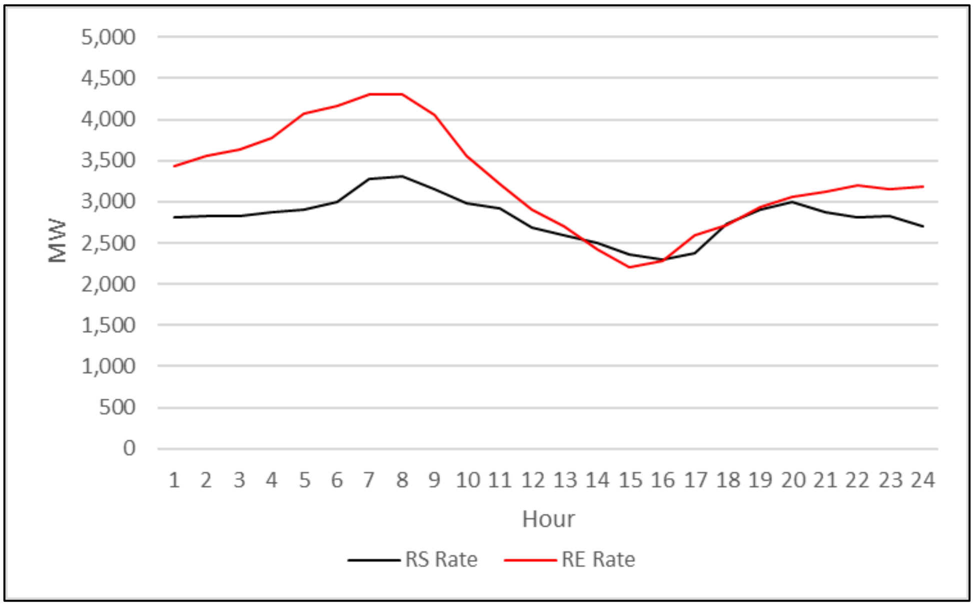


Figure 26 is the average of six winter peak days in 2018 for the RS and RE rates and shows the same profile as Figure 25, though the average morning and evening peaks are lower for each rate than the study peak day. The difference between study peak day and average winter peak day is about 900 MW, or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

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

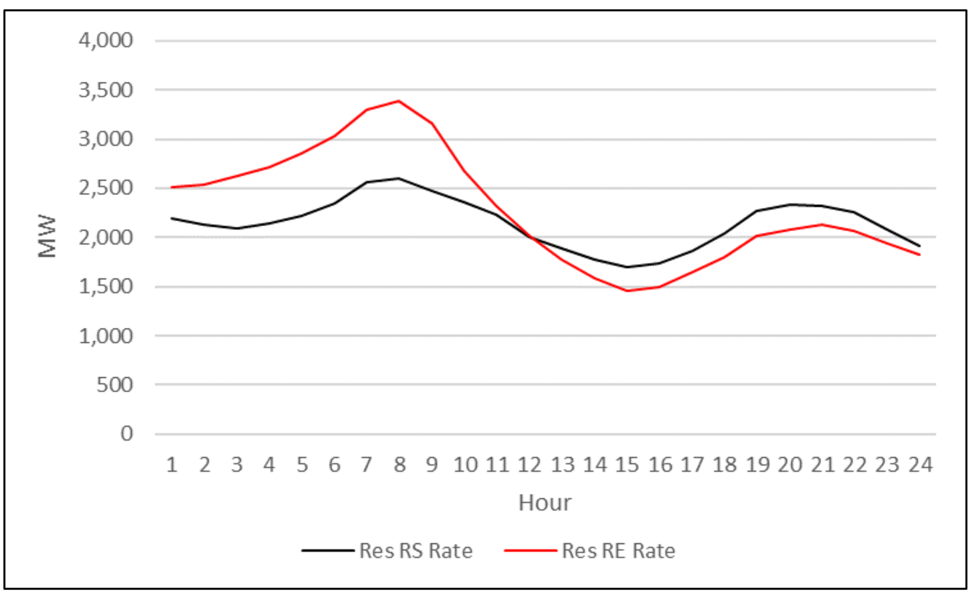


Figure 27 compares the TOU rate, RT, to the RT and RS rates, showing the average winter peak day demand profile over a 24-hour period for all three rates. We observe that the RT rate profile more closely aligns with the RE rate, with some slight shifts, but participation in the RT rate is very small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

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

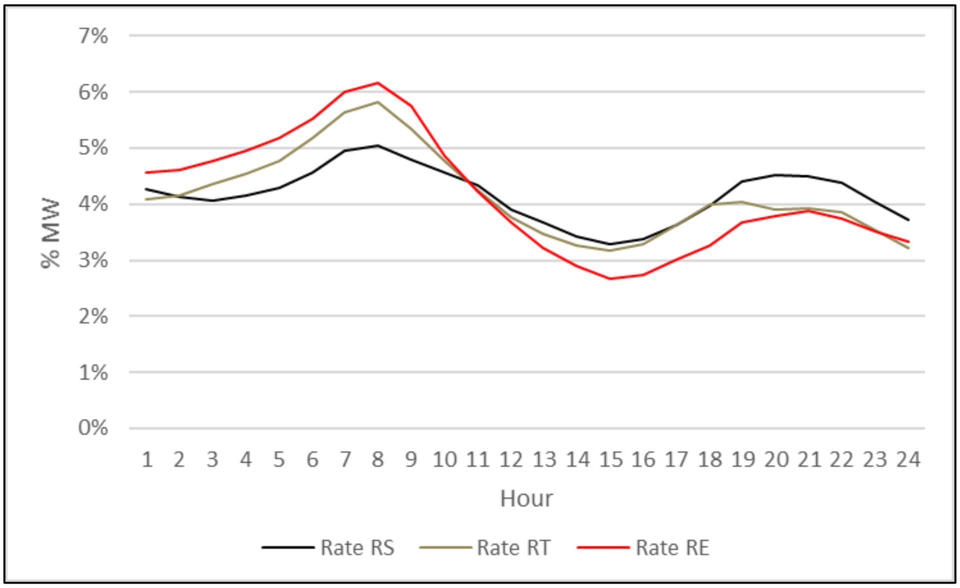


Figure 28 compares the average winter and summer peak for the RE rate for the 6 winter and 4 summer peak days previously defined at Table 3. On average, winter peak exceeds summer peak by about 1,000 MW. Because household appliances and hot water usage is generally consistent throughout the year, we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

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

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

[31] Excluding supplemental heat strips on HP heating systems

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

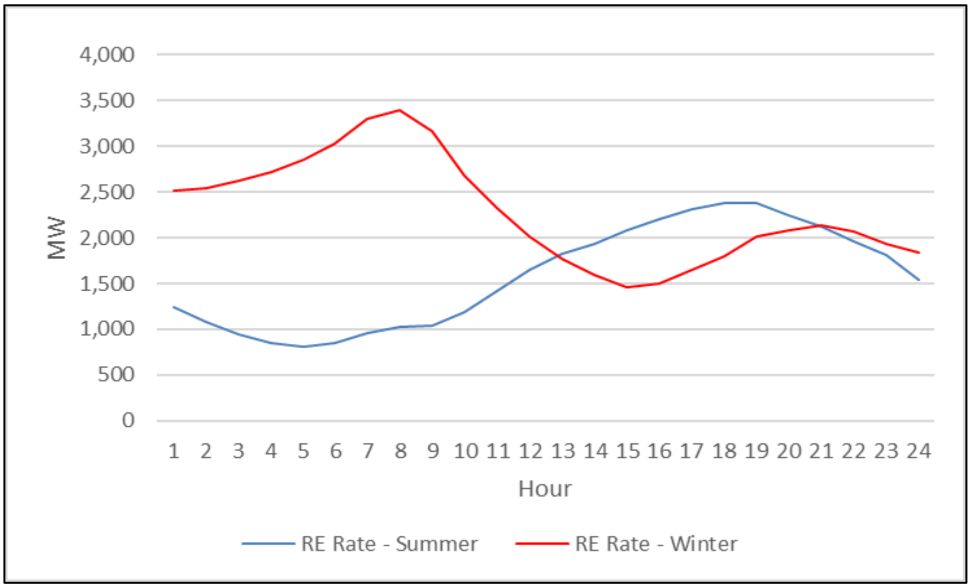
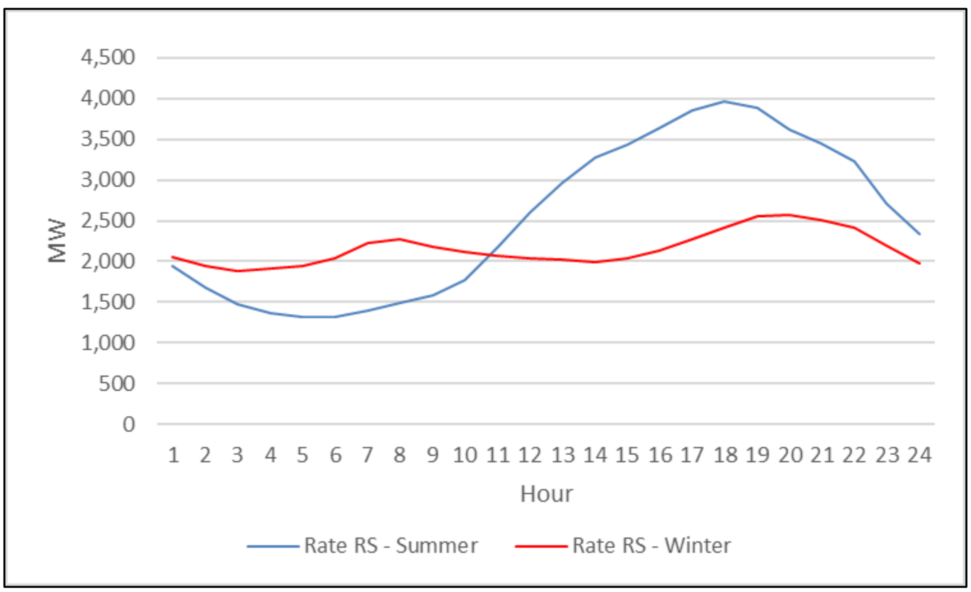


Figure 29 ccompares winter and summer peak for the RS rate for these same 6 winter and 4 summer peak days illustrating the considerable summer evening peak associated with AC demand. We expect that any thermostat solution targeted at winter peak will have benefits for summer AC demand.

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



DEP

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

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

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

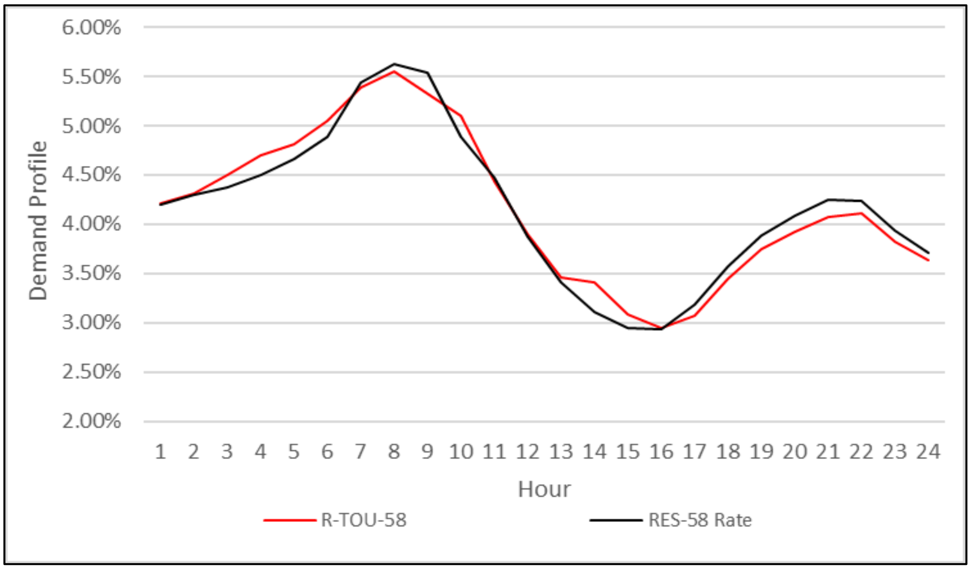
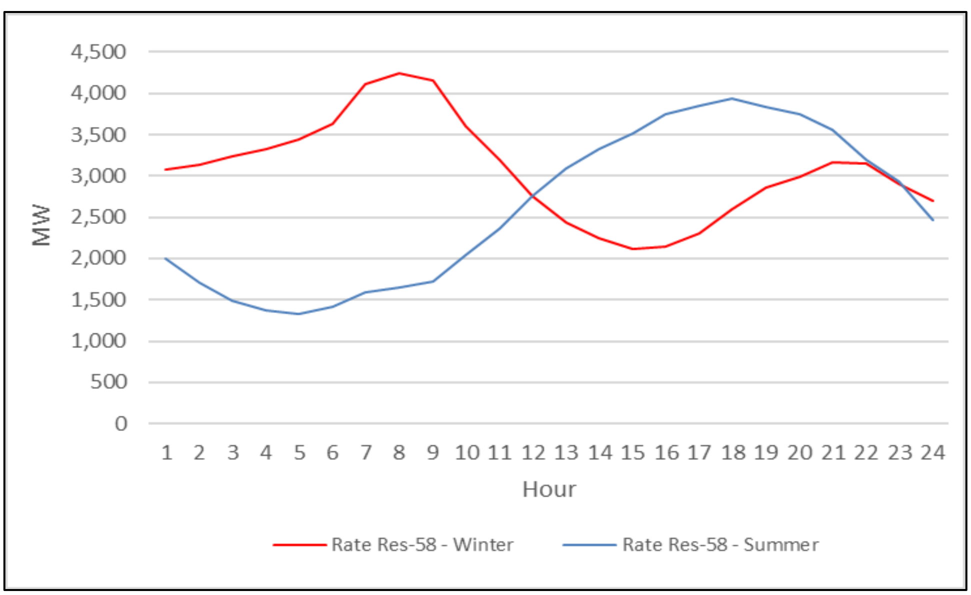


Figure 31 compares average winter and summer peak for the DEP R-TOU-58, and we do see a slight increase in R-TOU-58 average winter peak demand compared to summer, likely because this rate blends homes heated with electric heat and natural gas. Based on the demand differential observed between the DEC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

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



Market Characteristics

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

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

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

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

Table 20. Residential Occupant Type

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

We also used the ACS to estimate that 27% of NC and SC customer are low-income. Figure 33 shows how these are distributed by income cohort as a percent of FPL. From previous work completed by Tierra, Figure 34 shows that the lower a customer's income, the more likely they are to live in multifamily dwellings. We did not adjust our solutions set potential based on income cohort, but would note that implementing the solution set should consider the following with regards to low-income customers:

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

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

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

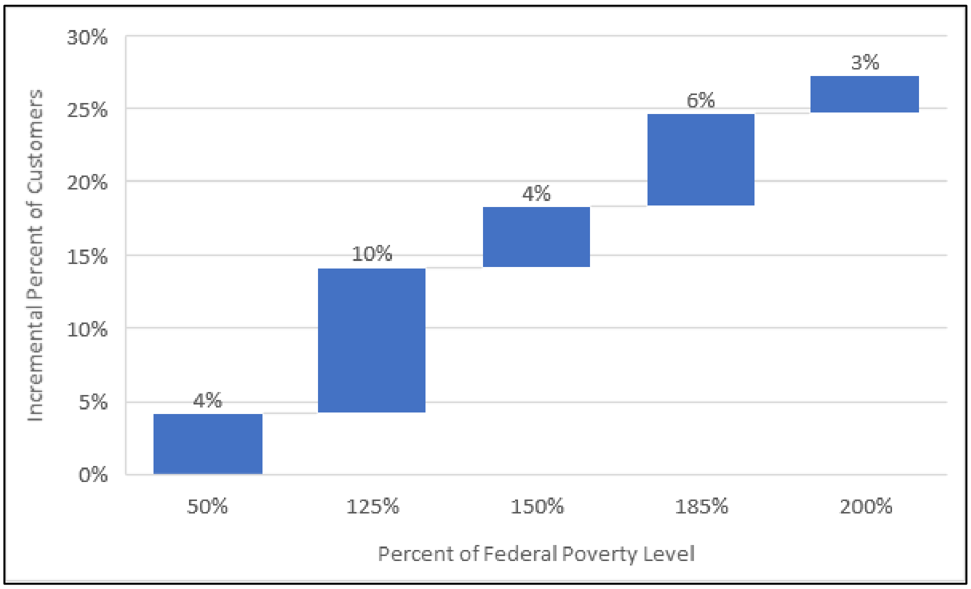
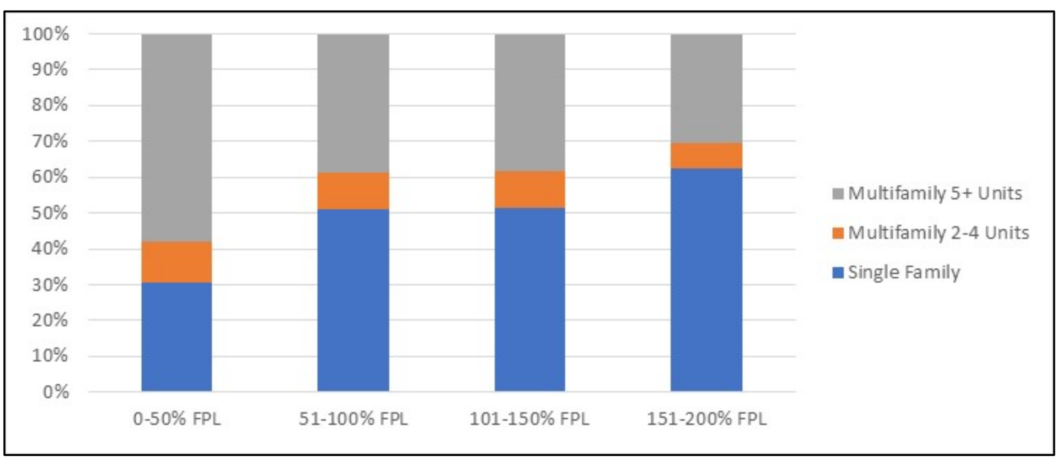


Figure 37. Residential Dwelling Types by FPL Income Cohort



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

Space Heating

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

Table 21. Primary Space Heat System Type by Utility

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

Table 22. Space Heat System Type by Resident Type

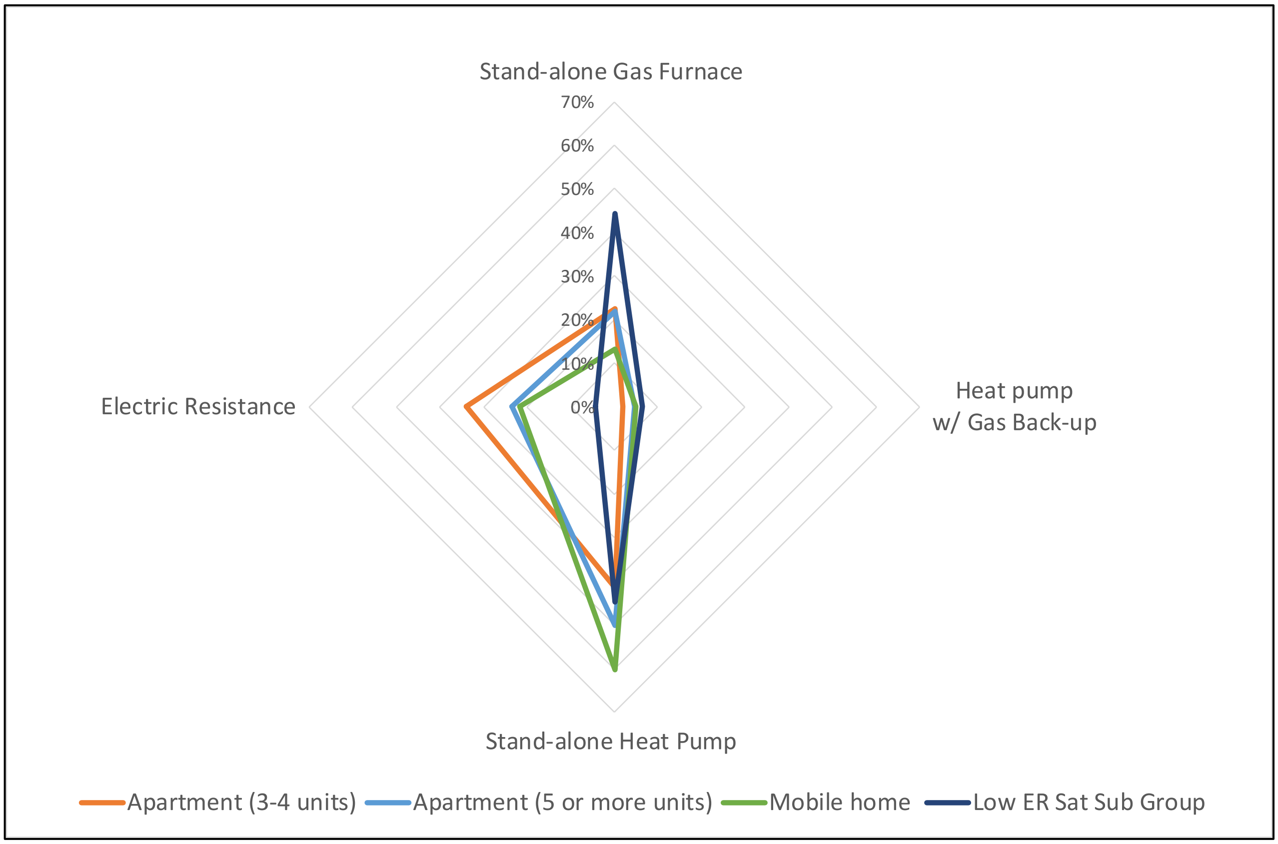
Resident Type	Stand-alone Gas Furnace	Heat Pump with Gas Back-up	Stand-alone Heat Pump	Electric Resistance	% Total Systems
Owner	79%	76%	74%	38%	73%
Renter	21%	24%	26%	62%	27%
Total	100%	100%	100%	100%	100%

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

Table 23. Space Heat System Type Distribution by Dwelling Type

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

Figure 38. Distribution of Electric Resistance Heating by Dwelling Type



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

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

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

Figure 39. Single Family Peak Load Profile - High User

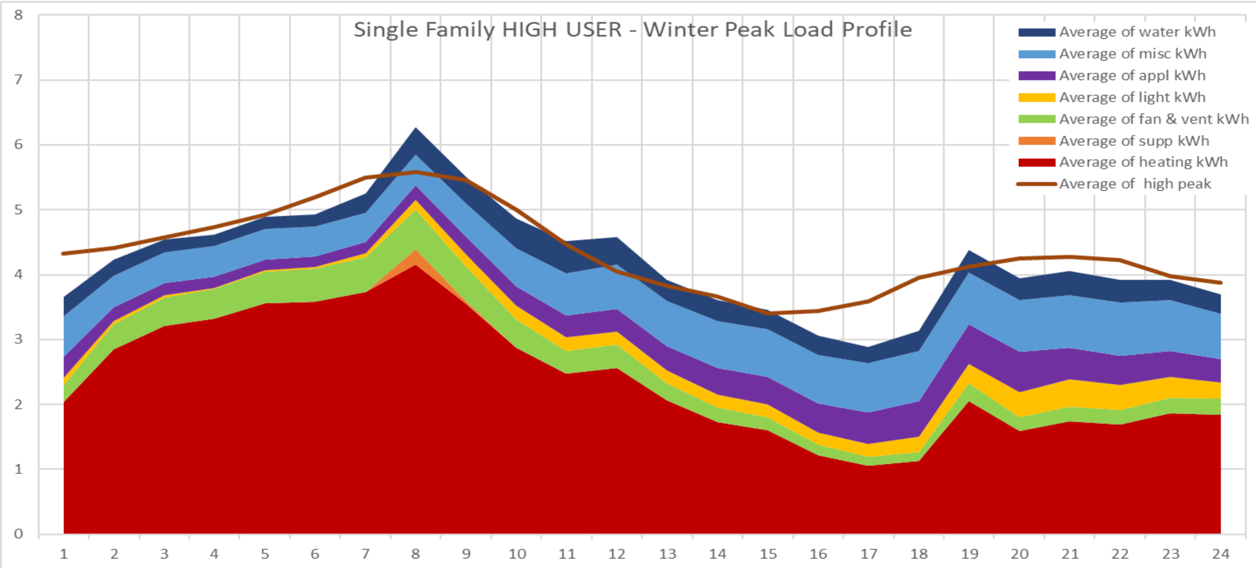


Figure 40. Single Family Peak Load Profile – Medium User

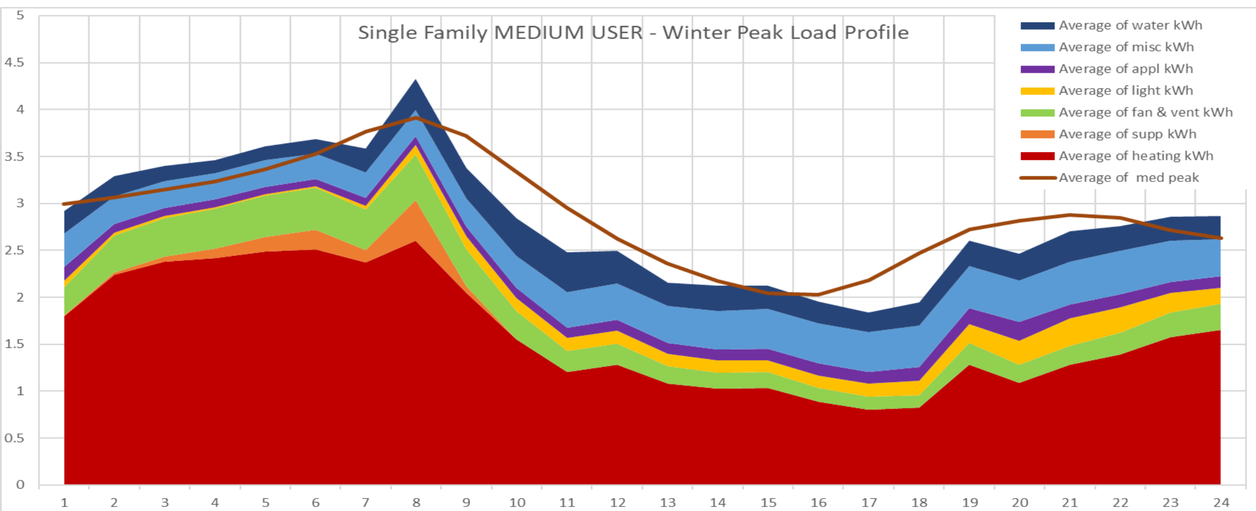
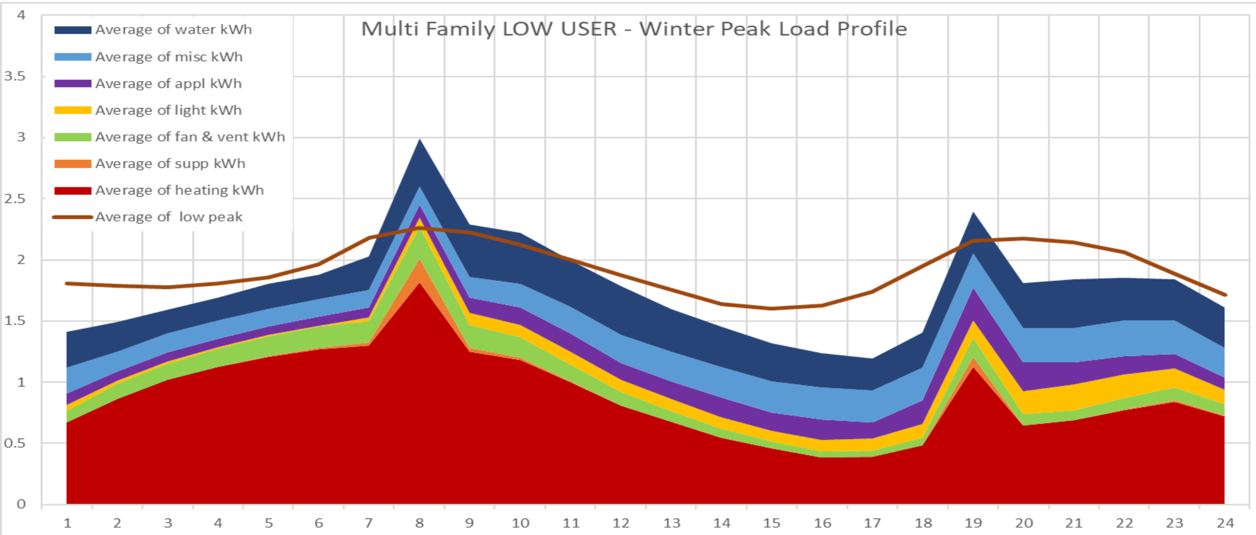
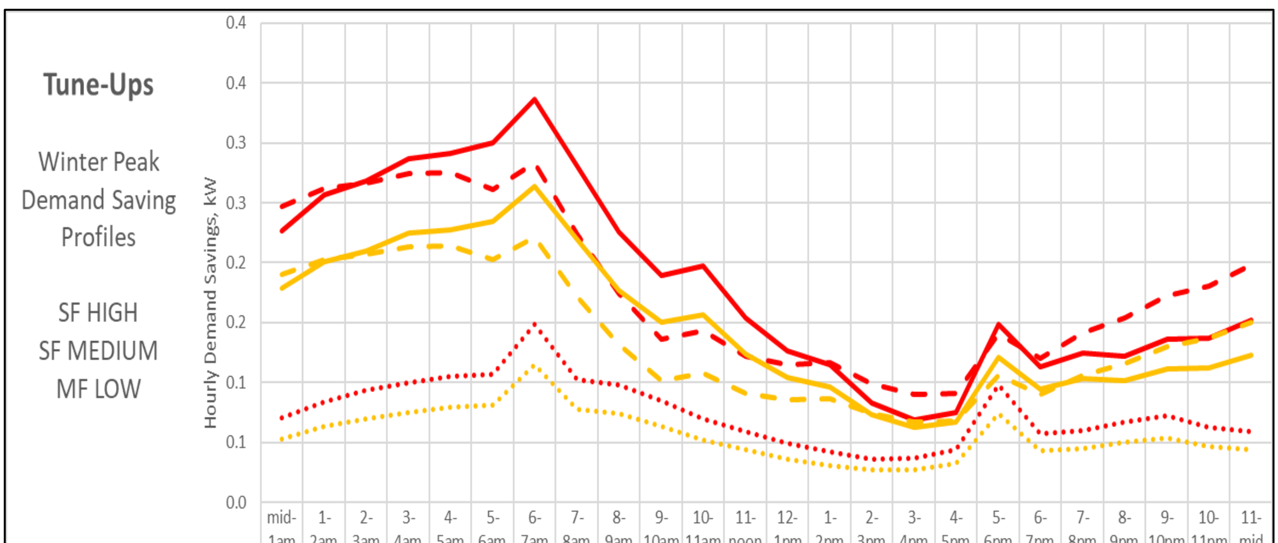


Figure 41. Multi-Family Peak Load Profile – Low User



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

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



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

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

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

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

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

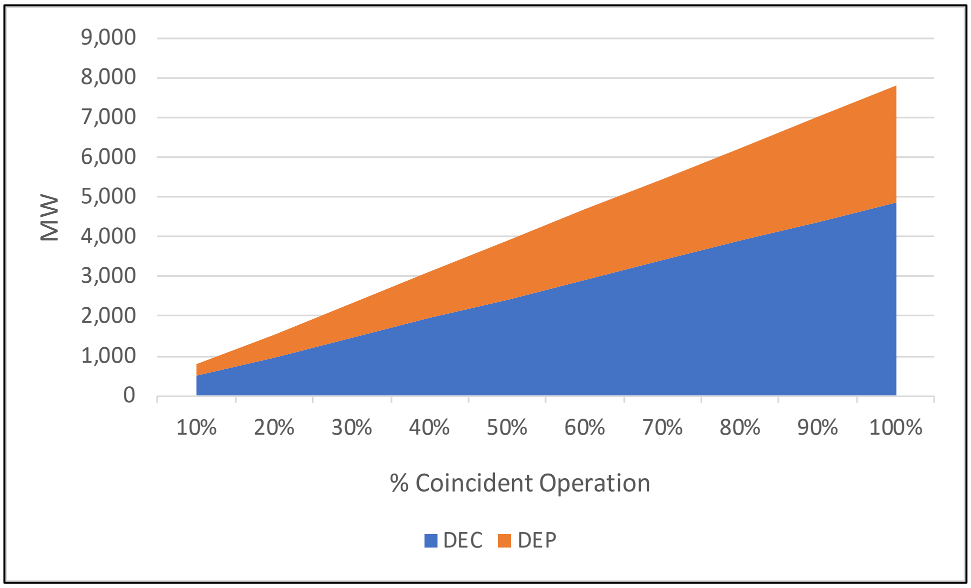
Table 25 shows technical demand from heat pump operation where technical demand is defined a worst-case scenario that assumes all system are operating simultaneously (i.e., 100% coincident operation). Reaching technical demand, is an unlikely event and Figure 40 shows the estimated heat pump loads at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

Table 25. Heat Pump Technical Demand

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

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

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



Thermostats

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

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

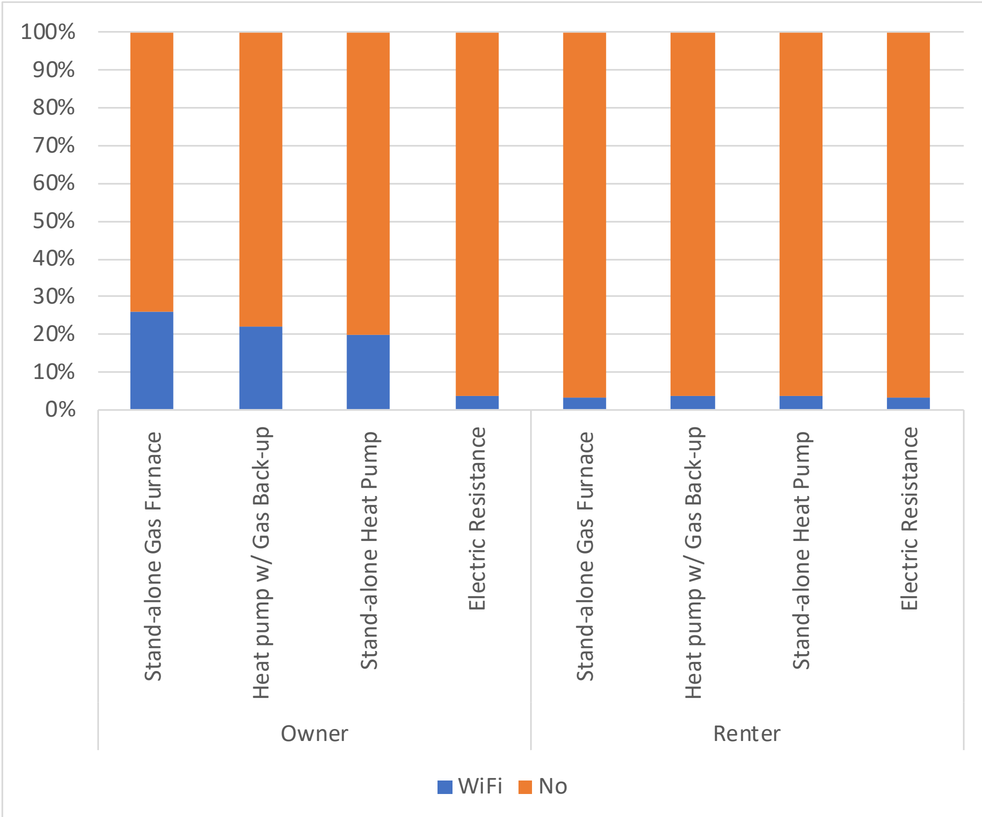
System Type	Wi-Fi
Stand-alone Gas Furnace	29%
Heat pump w/ Gas Back-up	26%
Stand-alone Heat Pump	24%
Electric Resistance	7%

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

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

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

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



Electric Water Heating

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

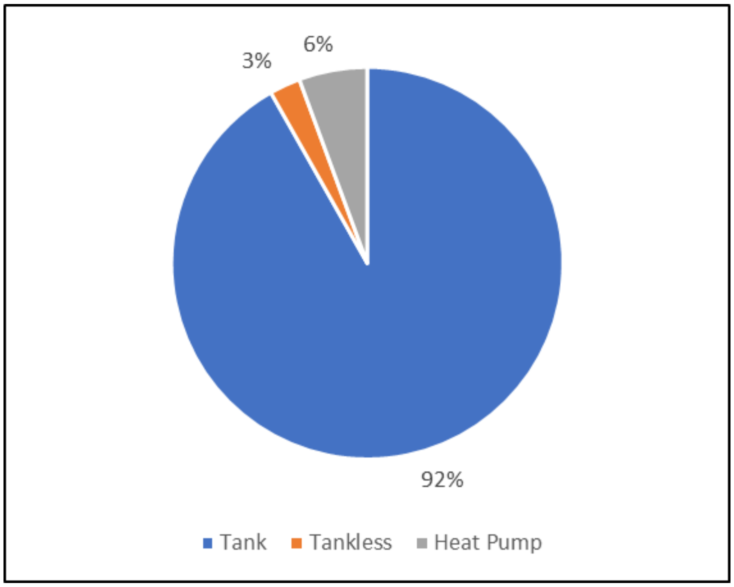
Table 28. Water Heat Fuel Type by Resident Type

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

Table 29. Water Heat Fuel by Dwelling Type

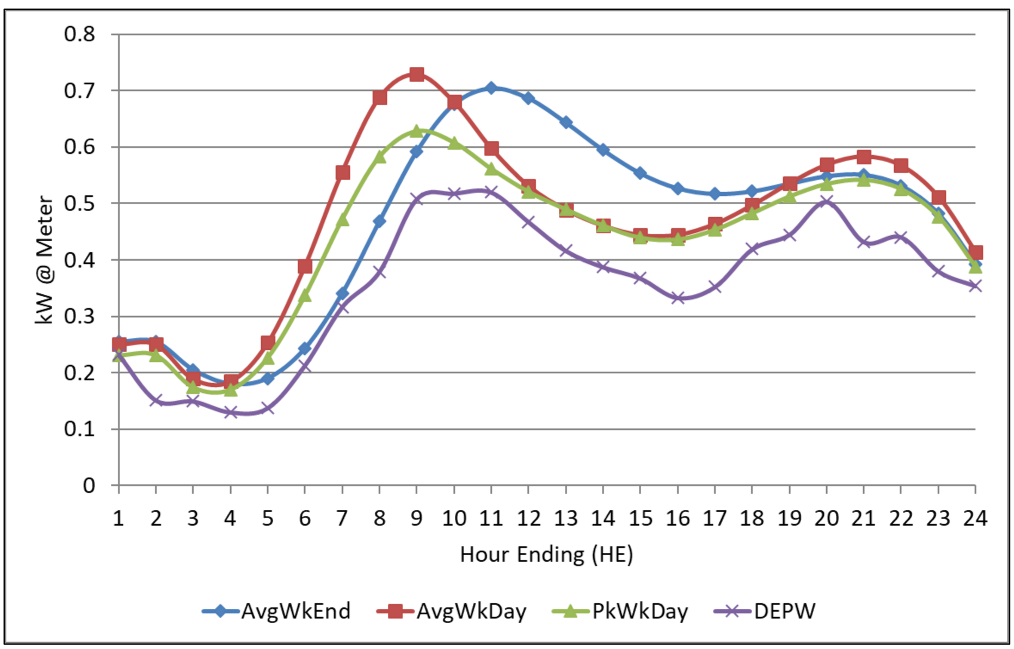
Resident Type	Fuel Type	Single-family detached	Single-family attached	Duplex	Condo	Apartment (3-4 units)	Apartment (5 or more units)	Mobile home
Owner	Electric	64%	50%	60%	76%			100%
	Natural Gas	36%	50%	40%	24%			0%
Renter	Electric	76%	82%	81%	84%	89%	91%	100%
	Natural Gas	24%	22%	19%	16%	11%	9%	0%

Figure 45. Water Heater Design Types



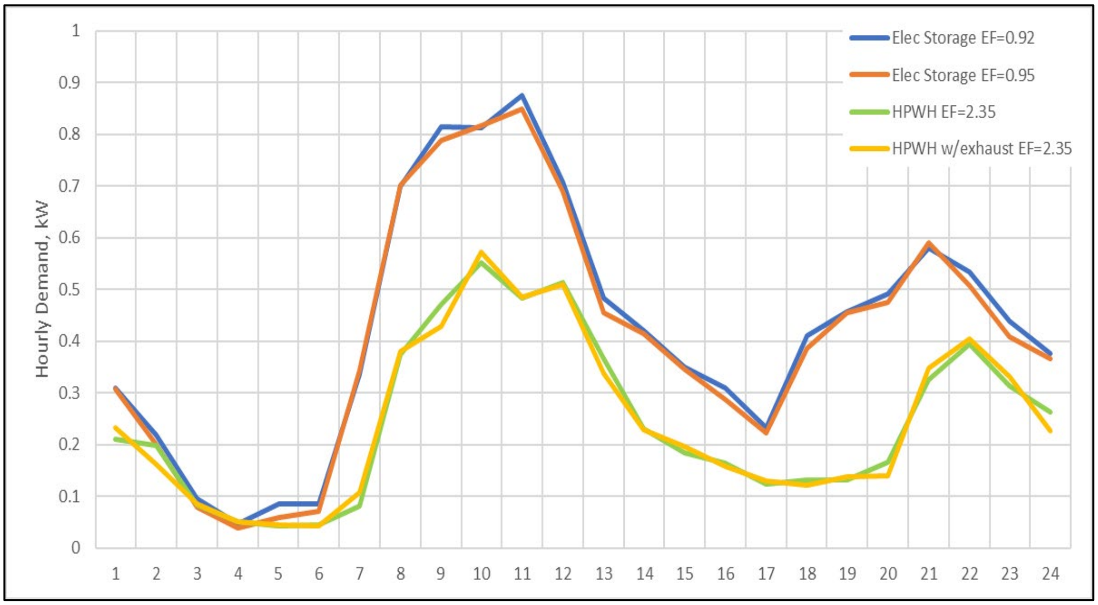
We reviewed various studies defining load shapes for electric water heaters, and these show load profiles similar to an EPRI study completed for the ECAR Region and DEP West, shown in Figure 43,[36] that feature a morning and evening peak. In general, these studies indicate weekday peak loads between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

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



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

Figure 47. Modelled Electric Water Heater Load Profiles



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

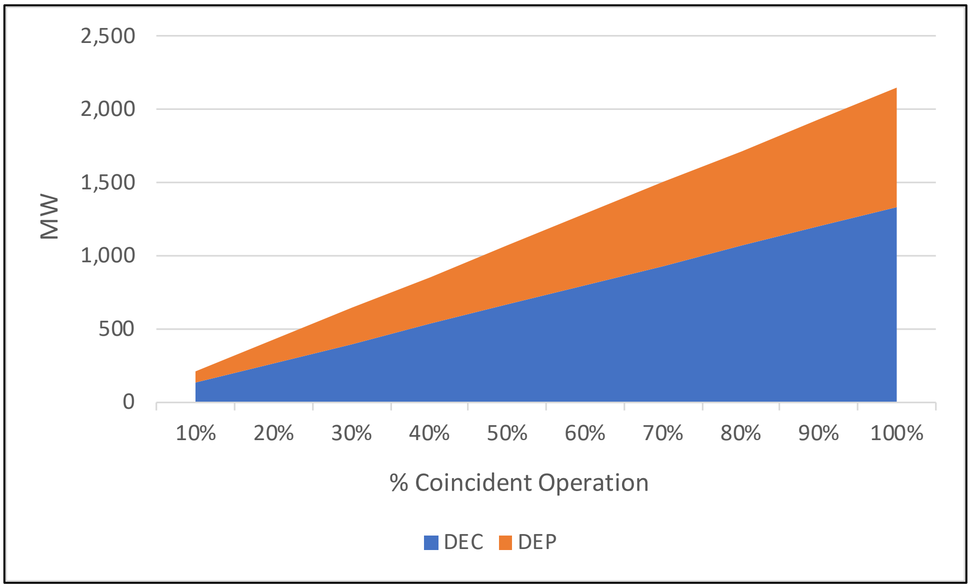
- As presented in 2019 RASS, 71% of all hot water heating systems are electric.
- Hot water heating represents about 10% of electric home demand during peak load periods where appliances and heat pumps are also operating coincident with the water heater.

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

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

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

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



Solution Set Recommendations

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

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

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

Bring Your Own Thermostat (BYOT)

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

Table 31. Hourly BYOT kW Impacts by Dwelling Type

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

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

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

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

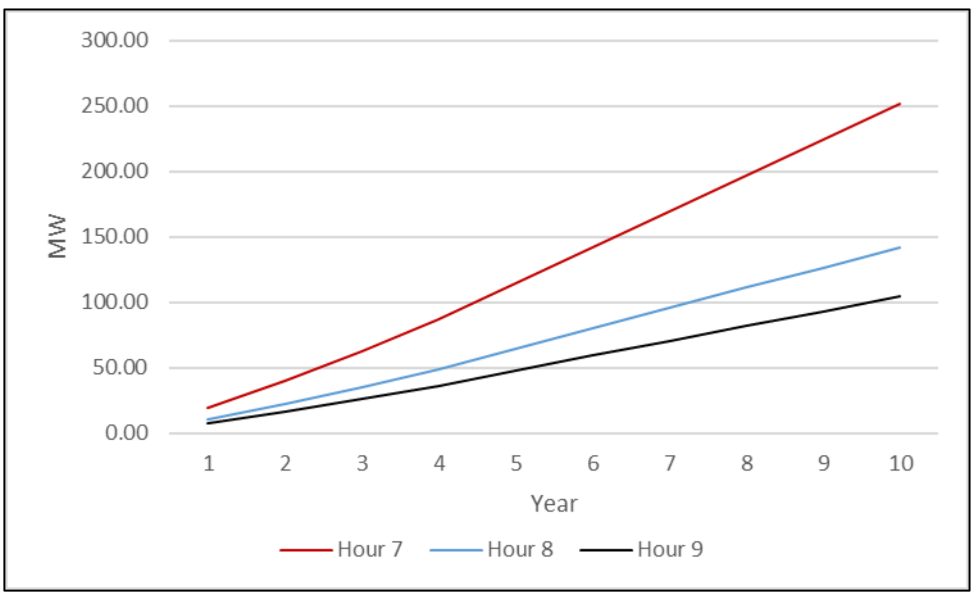
Hour Ending	5	6	7	8	9	10
SF	-1.38	-0.84	1.70	0.96	0.71	-1.04
MF	-0.60	-0.35	0.95	0.53	0.42	-0.45

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

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

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

Figure 49. 10-Year BYOT Savings Forecast by Hour



Rate Enabled Thermostats (RET)

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

Table 33. Hourly RET kW Impacts by Dwelling Type

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

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

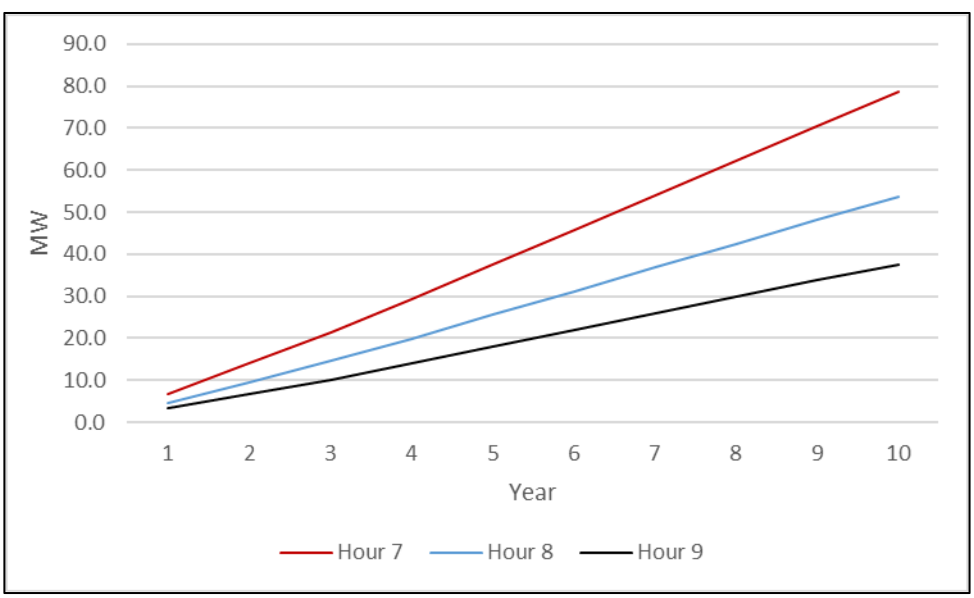
Hour Ending	5	6	7	8	9	10
SF	-2.23	-1.29	2.03	1.41	0.98	-1.67
MF	-1.02	-0.59	1.25	0.75	0.59	-0.76

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

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

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

Figure 50. 10-Year RET Savings Forecast by Hour



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

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

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

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

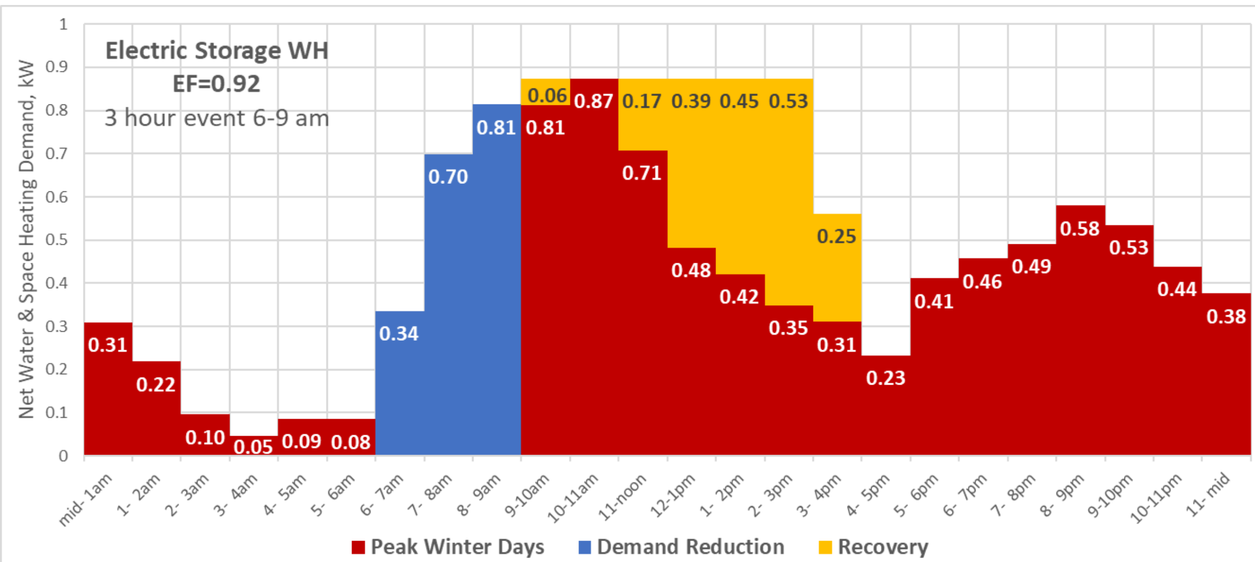
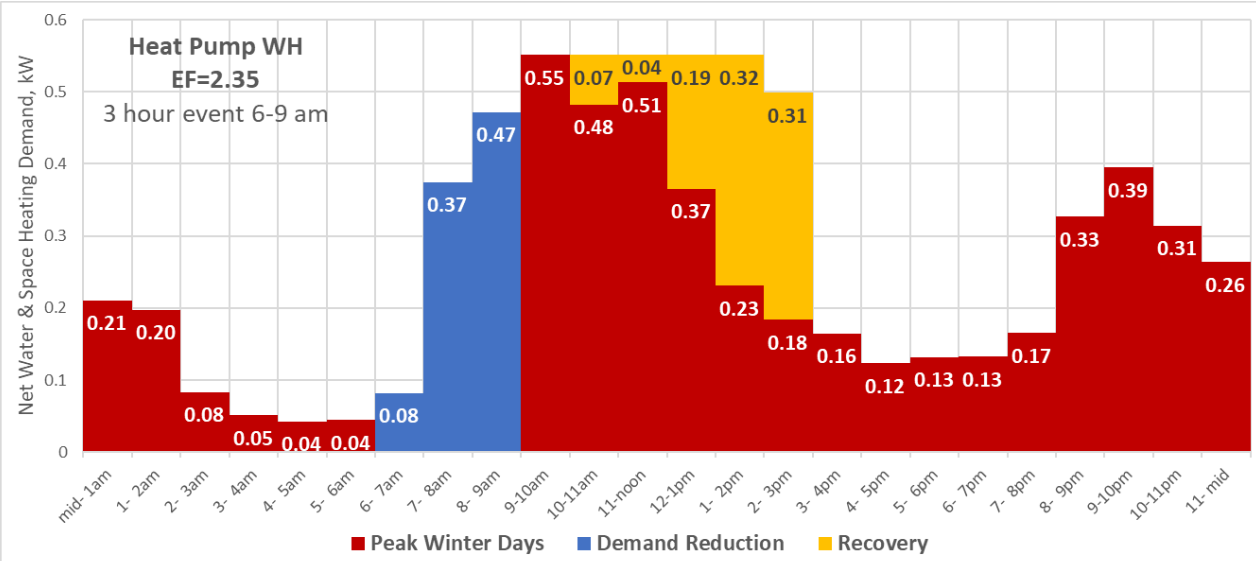


Figure 52. Modelled Heat Pump Water Heater Peak Load Shed Profile



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

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

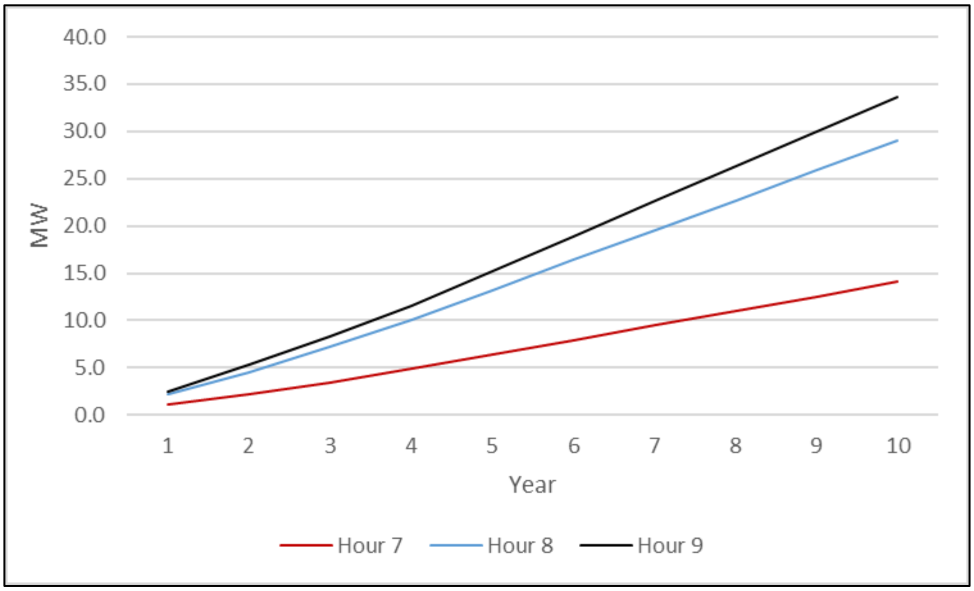
Hours Ending	5	6	7	8	9	10	11	12	13	14	15	16
SF	0.00	0.00	0.34	0.70	0.81	-0.06	0.00	-0.17	-0.39	-0.45	-0.53	-0.25
MF	0.00	0.00	0.26	0.53	0.61	-0.05	0.00	-0.13	-0.29	-0.34	-0.40	-0.19

Figure 50 shows the forecast by hour over a 10-year horizon based on the following assumptions:

- Annual growth during ramp: 10%
- Starting year 1 participation: 3,100
- Start Year: Dec-21

At the end of a 10-year implementation period we expect a peak load shed capacity of approximately 15MW in the hour ending at 7:00, increasing to 35MW during hour ending 9:00.

Figure 53. 10-Year RE-HWH Savings Forecast by Hour



5. Small and Medium C&I Market and Solutions

Rate Definitions

We segmented the commercial and industrial sector into two cohorts, small and medium C&I and large C&I, which is discussed later in this report. Small and medium C&I customers include the following rate types:

- General service rates that are not time differentiated (i.e., flat rates) though may have seasonal components.
- TOU rates targeting the same flat rate customers, but with demand threshold that are lower than TOU and RTP rates offered to larger C&I customers. These customers, in aggregate, account for only a small percentage of system load.

Table 36 provides summary rates for the small and medium C&I sector which align with the demand and consumption data reviewed for 2018, including the distribution between TOU and flat rates. Virtually all DEC small and medium C&I customers are on flat rates except for several TOU pilots with limited participation for small commercial customers. In general, DEC accounts for 40% of small and medium C&I customers and about 11% of total system demand, while DEP account for about 60% of small and medium C&I customers and about 17% of total system demand. About 63% of DEP customer are on flat rates, with the remainder of TOU rates applicable to small, medium, and large customers. Overall, TOU rates account for 22% of demand for the small and medium C&I rates defined in Table 36, the majority of which is associated with the DEP MGS-TOU.

Table 36. Small and Medium C&I Rates Summary

System	Schedule	Tier Type	Winter On-Peak	Winter	Study Peak Day MW	% C&I Cohort Demand	KW Cap
DEC	SGS	Tiered kWh and KW	None	None	1,154	17%	<50
	SGS-CPP (Pilot)	As Posted	6:00 a - 10:00 a	Oct – April			<50
	SGS-TOU-CPP (Pilot)	As Posted	6:00 a - 10:00 a	Oct – April			<50
	SGS-TOUD-DPP (Pilot)	As Posted	6:00 a - 10:00 a	Oct – April			<50
	LGS	Tiered kWh and KW	None	None	1,091	16%	>75
	I	Tiered kWh and KW	None	None	470	7%	None
DEP	SGS	Tiered kWh	None	None	557	8%	<30
	SGS-TOUD-58	On/Off kWh	6:00 a - 1:00 p	Sept - Mar	64	<1%	>30
	SGS-TOUE-58	On/Should/Off kWh	6:00 a - 1:00 p	Sept - Mar			>30
	MGS-58	None	None	None	1,853	27%	30<1,000
	MGS-TOU	Not reviewed	Not reviewed	Not reviewed	1,212	18%	30<1,000
	LGS-58	Tiered KW	None	Oct – June	189	3%	>1,000
	LGS-TOU-58	Tiered kWh and KW	6:00 a - 1:00 p	Oct – May	290	4%	>1,000

Peak Load Profile

The following section provides observations for DEC and DEP load profiles based on a review of 8,760 hourly load data for the small and medium C&I rates defined in Table 37.

DEC

Figure 51 shows average summer and winter peak day as defined at Table 3 for SGS, indicating higher demand during summer is likely due to air conditioning, if demand from other commercial equipment (e.g., lighting, office equipment, process equipment, etc.) are not weather sensitive and constant throughout the year. To assess sensitivity to weather events in the winter, Figure 52 compares demand between the study peak day and the average winter peak days, showing a difference of 71 MW, which we attribute to increased electric heating loads.

Figure 54. DEC 2018 SGS Demand Profile – Average Season Peak Day

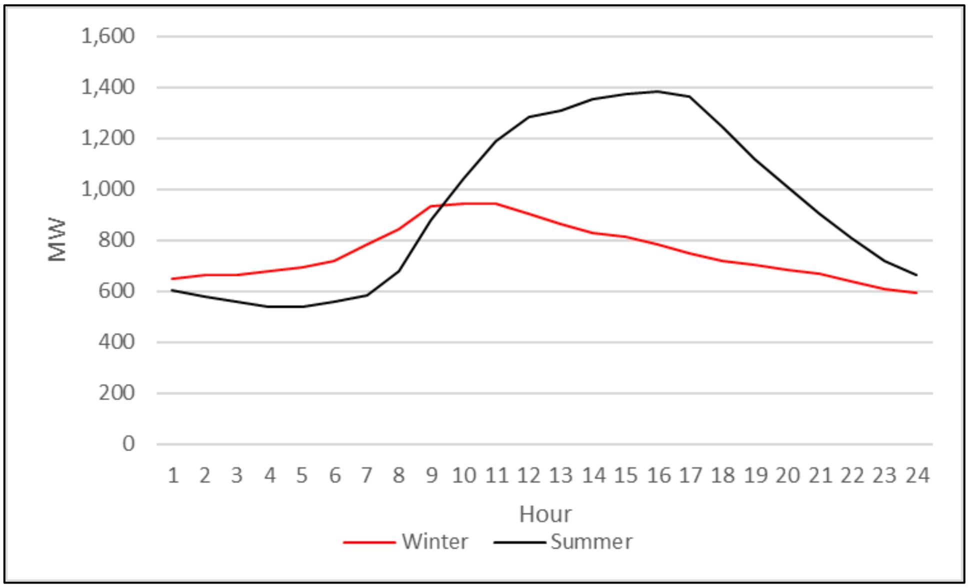
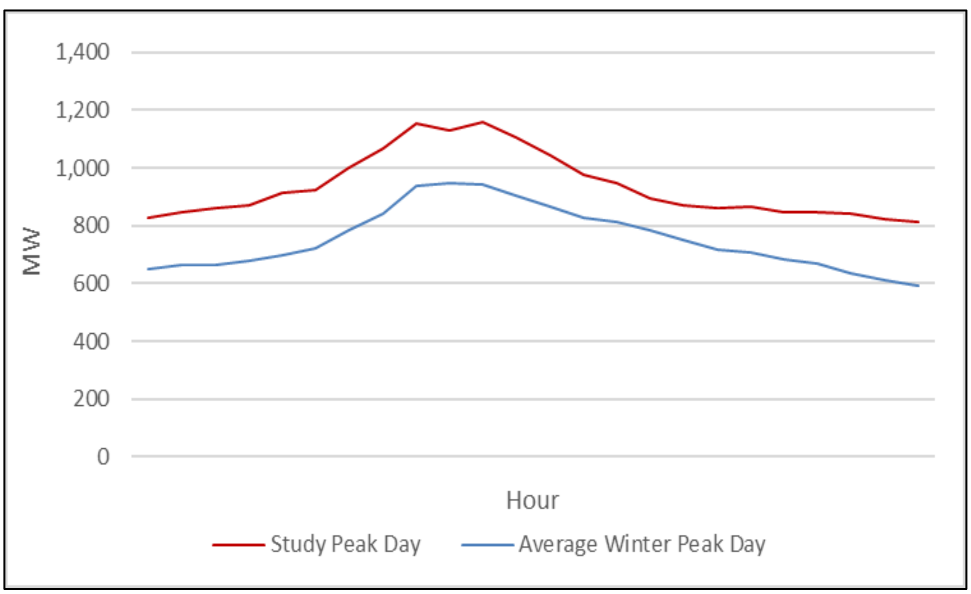


Figure 55. DEC 2018 SGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



We completed a similar analysis for the DEC LGS rate and Figure 53 shows average summer and winter peak day for LGS, like the SGS rate. Figure 54 compares demand between the study peak day and the average winter peak days, showing a difference of 11 MW, indicating this rate class is minimally sensitive to weather events.

Figure 56. DEC 2018 LGS Demand Profile - Average Season Peak Day

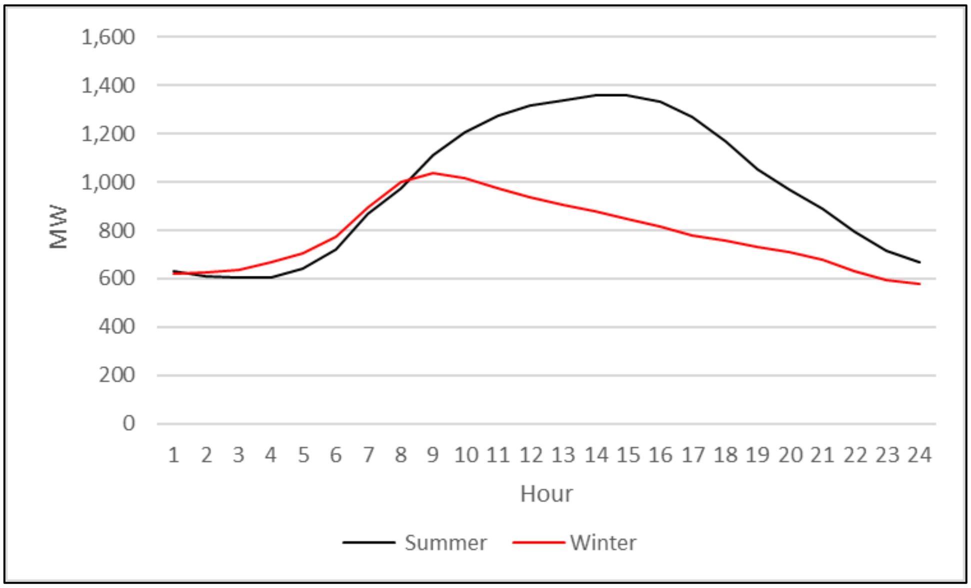


Figure 57. DEC 2018 LGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day

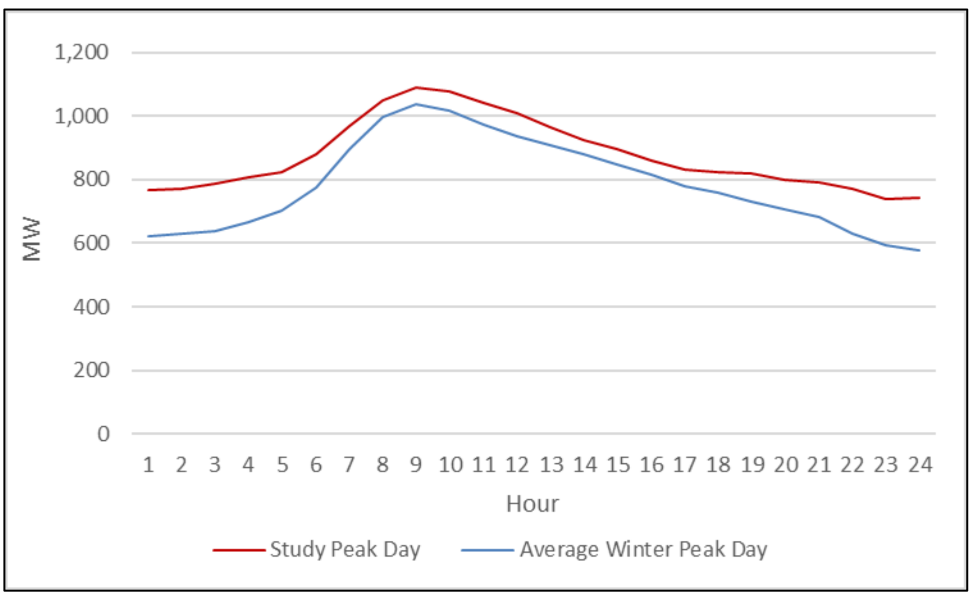


Figure 55 and Figure 56 show a similar review of the DEC Ind rate, indicating that these customers are a blend of industrial and commercial operations though no segment data was provided. These load shapes are virtually identical, and while there is some demand associated with electric heating, most of the demand is likely from non-weather sensitive loads. The difference in demand between the study peak day and the average winter peak days, showing a difference of 30 MW, or an increase of about 5%, indicating that this rate class is not very sensitive to weather events.

Figure 58. DEC Ind Demand Profile - Average Season Peak Day

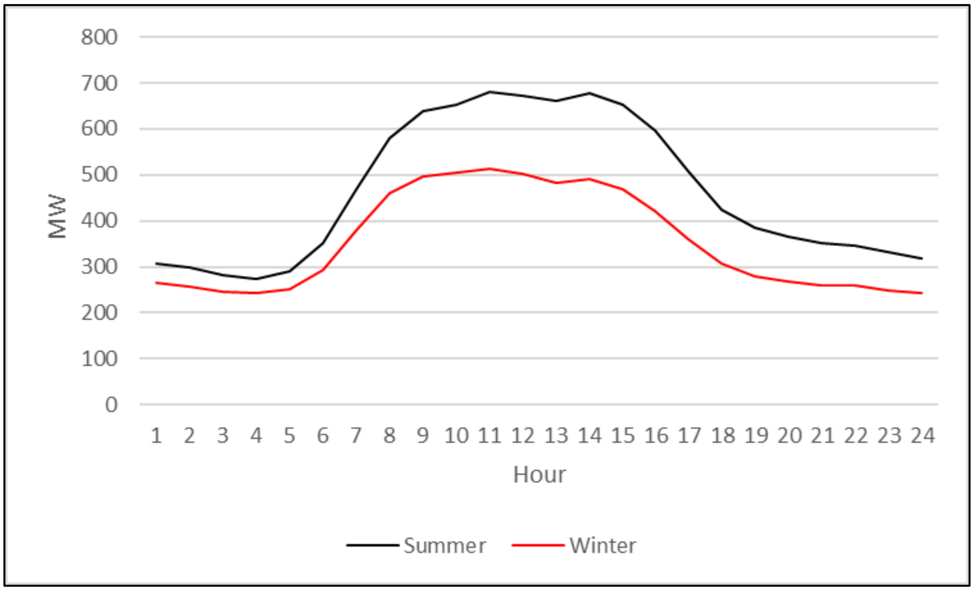
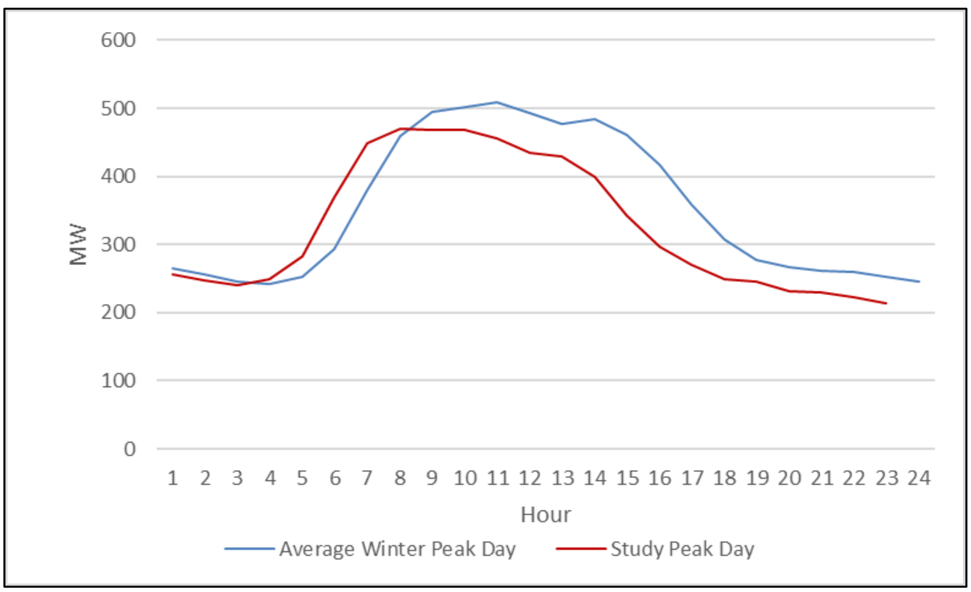


Figure 59. DEC 2018 Ind Demand Profile – Study Peak Day Vs. Average Winter Peak Day



The data reviewed for the SGS, LGS, and Industrial rates allowed us to complete a rough estimate of morning heat loads by averaging demand during a heating period that we defined from 8:00 am to noon, minus the average afternoon demand occurring during other business day hours from 1:00 p.m. to 5:00 p.m. Table 37 shows the average hourly winter morning heating demand (MW) by C&I rate for the study peak day as well as the average of 6 winter peak days, indicating a difference 112 MW between the average winter peak and annual system peak.

Table 37. DEC Average Winter Peak Morning Heating Demand (MW) by Rate

Rate	SGS	LGS	Ind	Total
Study Peak Day MW	177	158	82	417
Ave Peak Day MW	106	147	52	305

DEP

As noted at Table 37, about 63% of DEP C&I customer are on rates that have no time differential and 37% are on TOU rates, including the combinations:

- SGS and SGS-TOU
- MGS and MGS-TOU
- LGS and LGS-TOU

We compared the aggregate C&I load shapes for flat rate and TOU customers as shown in Figure 57 for 6 winter system peak days and Figure 58 for 4 summer system peak days in 2018. Because of the high saturation of TOU across DEP general service customers (37%) this analysis implies a response that shifts demand off-peak during winter peak (6:00 a.m. - 1:00 p.m.) and summer peak (10:00 a.m. -10:00 p.m.). We did not research if these are behavioral driven (i.e., actively managing demand during peak) or simply customers selecting a TOU rate that is best suited to their standard operating profile. We caveat this analysis because the data provided to us included TOU customers within the flat rate totals (e.g., the SGS load profile includes the SGS-TOU, etc.). Had flat rate and TOU been broken out as discrete profiles we expect the difference between flat rate and TOU customers would be more pronounced.

Figure 60. DEP Small-Medium C&I Aggregate Rate Demand Profile - Average Winter Peak Day

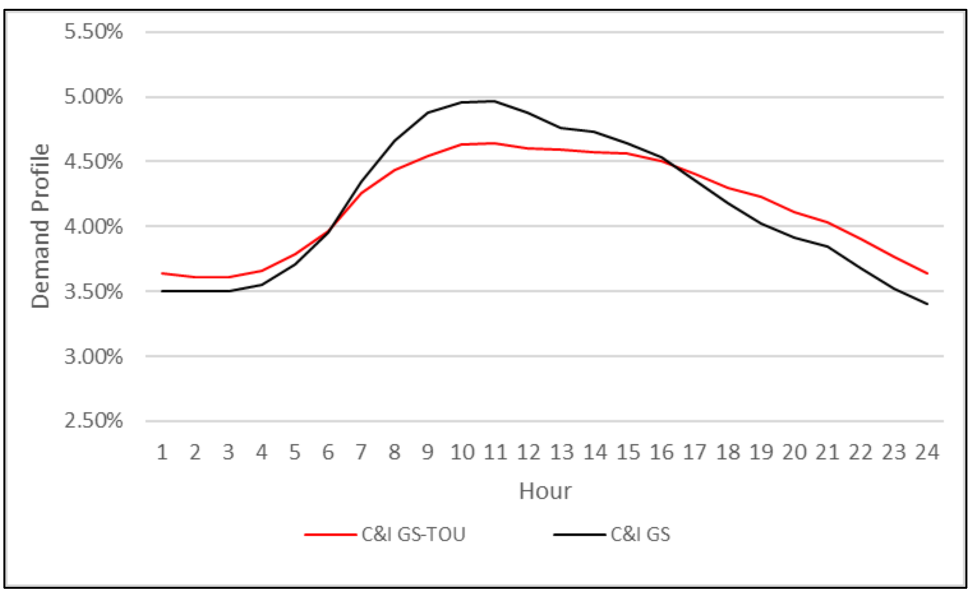
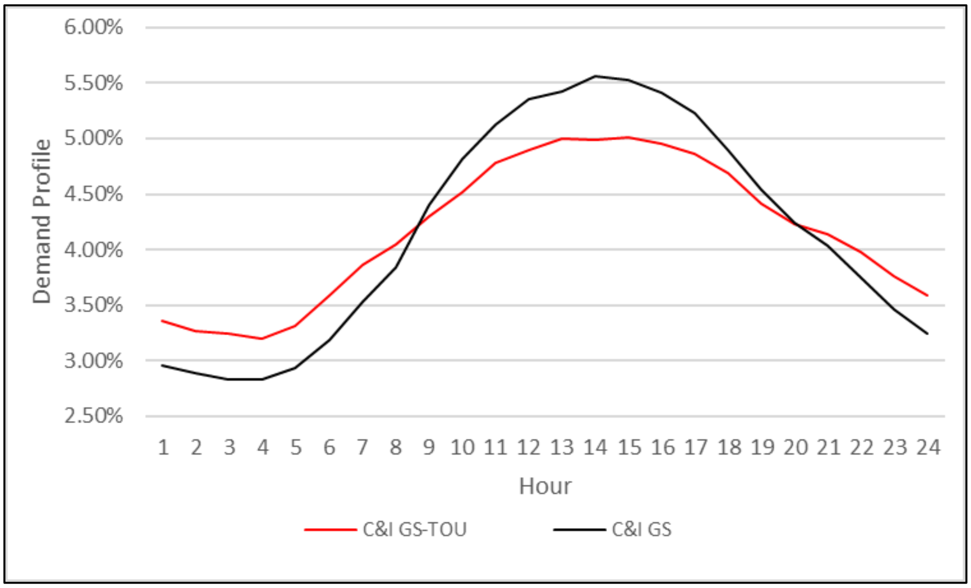


Figure 61. DEP Small-Medium C&I Aggregate Rate Demand Profile - Average Summer Peak Day



Like the DEC SGS analysis, Figure 59 shows average summer and winter peak day for DEP SGS, indicating higher demand during summer is likely due to air conditioning. Figure 60 compares demand between the study peak day and the average winter peak days, showing a difference of 127 MW, or an increase of about 25% between the study peak and average winter peak day, indicating that this rate class is sensitive to weather events.

Figure 62. DEP 2018 SGS Demand Profile - Average Season Peak Day

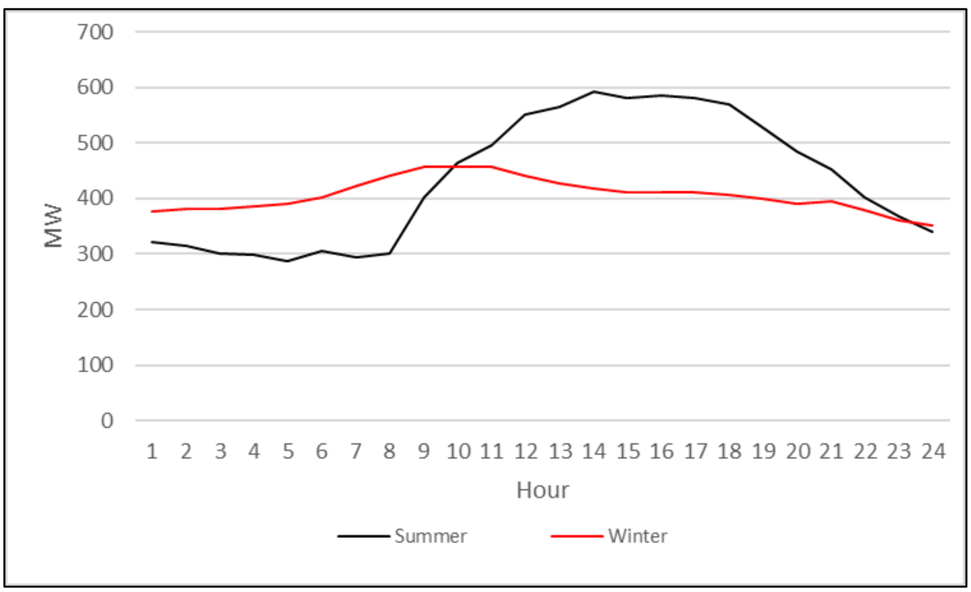
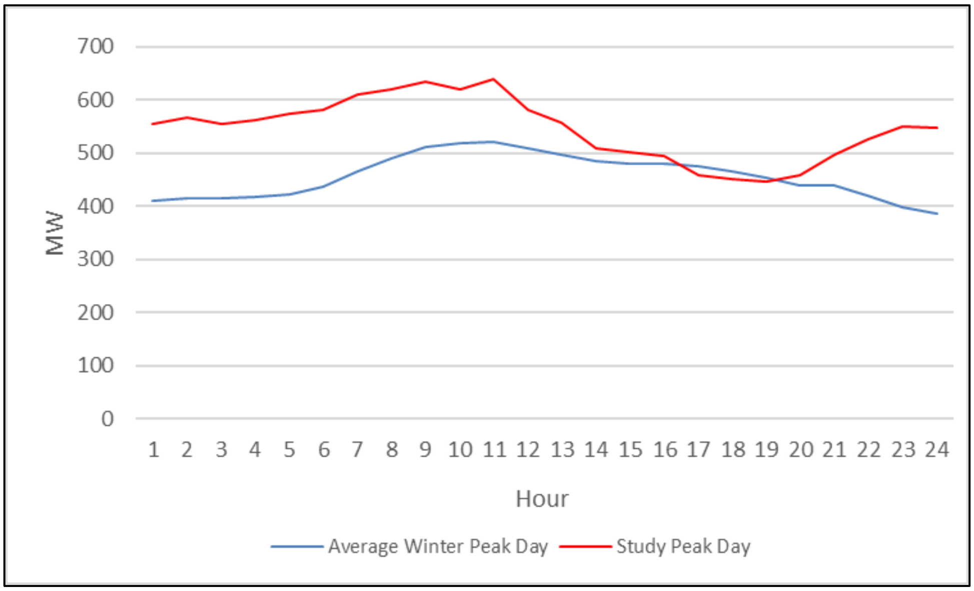


Figure 63. DEP 2018 SGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



Similarly, Figure 61 shows average summer and winter peak day for MGS, indicating a higher demand during summer similar to the SGS rate. Figure 62 compares demand between the study peak day and the average winter peak days, showing a difference of 4 MW, indicating that this rate class has demand associated with heating, but it is not sensitive to weather events.

Figure 64. DEP 2018 MGS Demand Profile – Average Season Peak Day

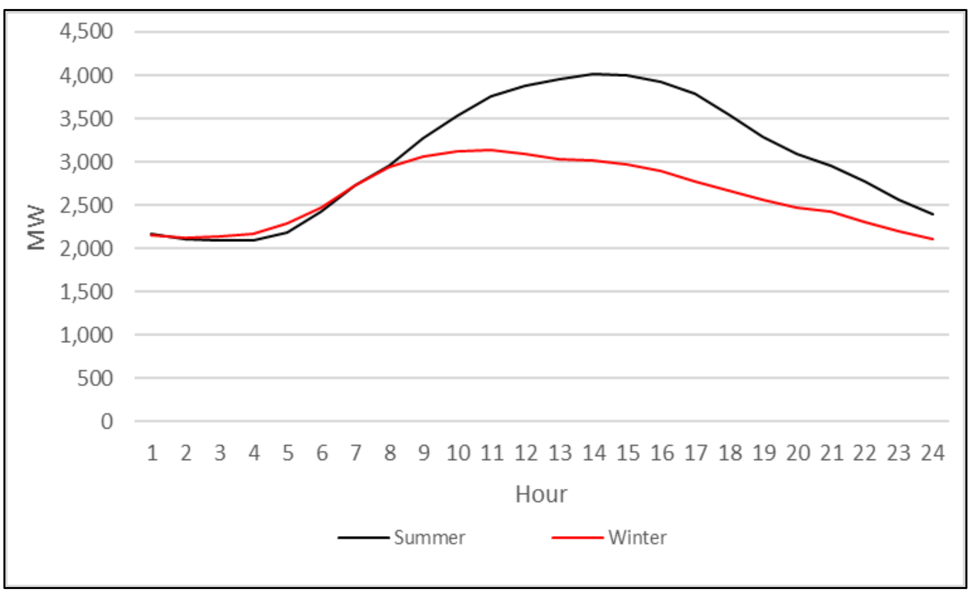


Figure 65. DEP 2018 MGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day

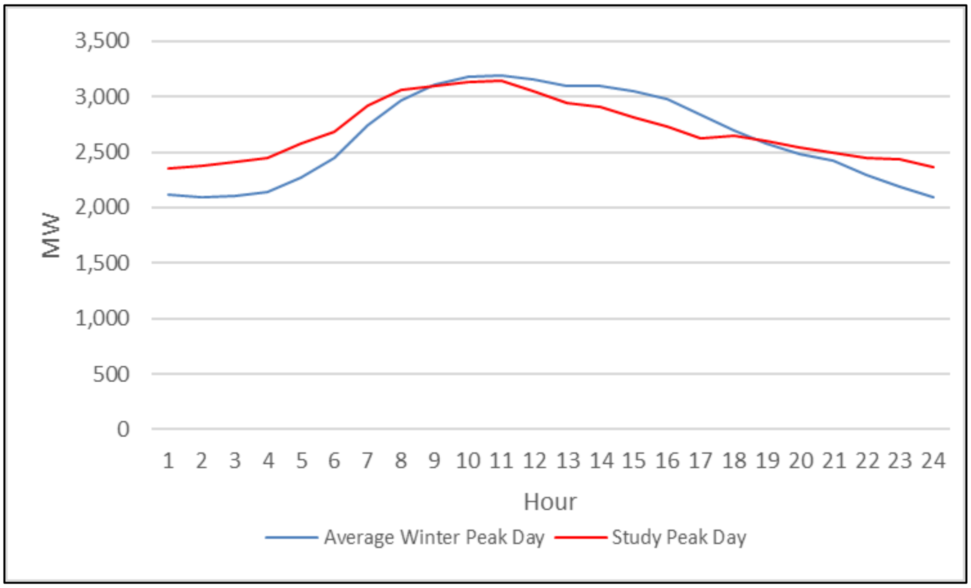


Figure 63 shows average summer and winter peak day for the LGS rate, indicating a higher demand during summer, similar to the SGS rate. Figure 64 compares demand between the study peak day and the average winter peak days, showing a difference of -8 MW, indicating that this rate class is not sensitive to weather events.

Figure 66. DEP 2018 LGS Demand Profile – Average Season Peak Day

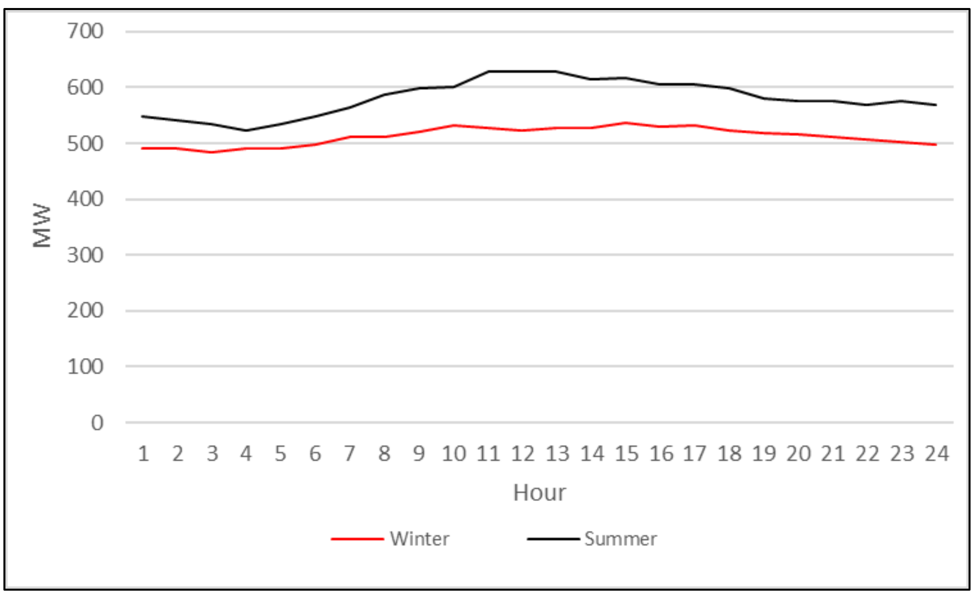
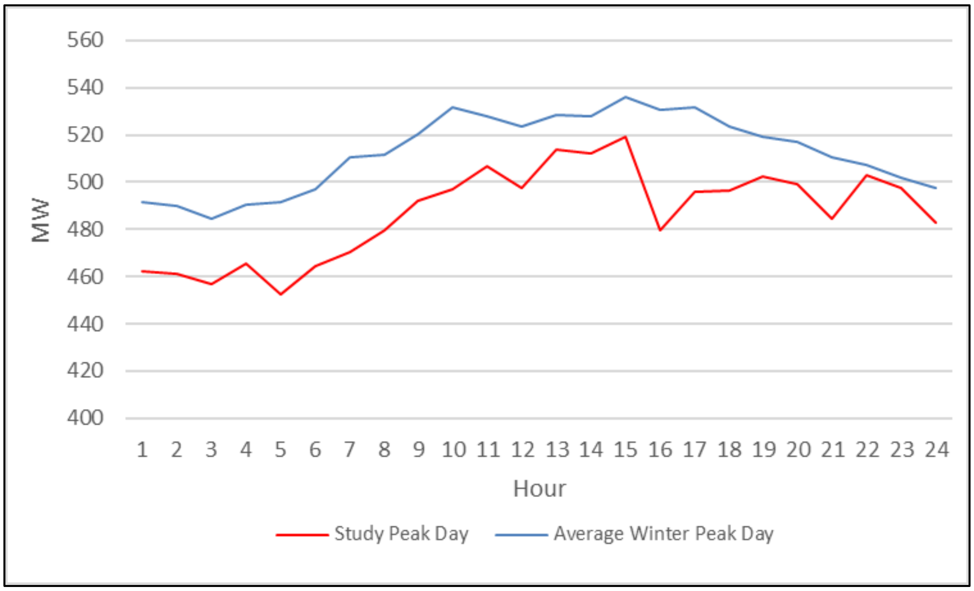


Figure 67. DEP 2018 LGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



Using the methodology described for DEC, Table 38 shows the average hourly winter morning heating demand (MW) by C&I rate for the study peak day and average of 6 winter peak days, indicating a difference of 34 MW between the average winter peak and annual system peak. We estimate that there is no appreciable winter space heating demand for LGS customers.

Table 38. DEP Average Hourly Winter Peak Heating Demand (MW) by Rate

Rate	SGS	MGS	LGS	Total
Study Peak Day MW	127	292	-6	413
Ave of Peak Day MW	92	288	-14	366

Table 38 summarizes our estimates of winter peak electric heating demand by rate for DEC and DEP.

Table 39. Average Hourly Winter Peak Electric Heating Demand (MW) by Rate

Utility	Rate	SGS	MGS	LGS	Ind	Total
DEC	Study Peak Day MW	177	-	158	82	417
	Ave Peak Day MW	18	-	82	51	151
DEP	Study Peak Day MW	127	292	-6		413
	Ave of Peak Day MW	92	288	-14		366
Total	Study Peak Day MW	304	292	152	82	830
	Ave Peak Day MW	52	109	78	51	517

To gain further perspective on DEP C&I winter heating loads, we reviewed 2018 data for 327 DEP large accounts, most of which will be flat rate customers but some of which are RTP customers. We binned this data to define customers with average winter morning peak demand that equals or exceeds average winter demand for the balance of the business day. For this analysis, the morning period we defined the morning heating period as hours ending 7:00 through 9:00, and the balance of the business day was defined as hours ending 10:00 through 5:00.

Table 40 shows that 39% of 327 large accounts have average morning demand exceeding afternoon, accounting for 57% of average morning load, or 639 MW out of 1,129 MW of the average demand for 327 DEP large accounts for hours 7:00 through 9:00.   To refine this estimate, we looked at customers the morning peak exceeding the balance of the business day demand by 110% and 120% At the extreme about 23 customers (7%) have morning peak exceeding the balance of the business day by 120%, or 84 MW out of 1,129 MW average morning demand for the accounts reviewed.

Table 40. DEP Large Commercial Customer Morning Demand Comparison – Average Season Peak Day

Bin	Customers	% of Customers	Average Morning Demand (MW)	% of Total Average Morning Demand
100%	129	39%	639	57%
110%	46	14%	222	20%
120%	23	7%	84	7%

Figure 65, Figure 66, and Figure 67 show the demand profiles for our analysis bins, showing a clear morning peak for accounts where morning peak exceeded afternoon peak by 120%. Collectively, this analysis indicates:

- About 40% of these customers likely use natural gas for most of their heating.
- Between 50% and 60% % of customers have some electric heat, likely for space heating, and this accounts for about 148 MW of winter morning peak for hours ending 7:00 through 9:00.

Figure 68. DEP Large C&I Morning Peak Exceeds Afternoon Peak – Average Season Peak Day

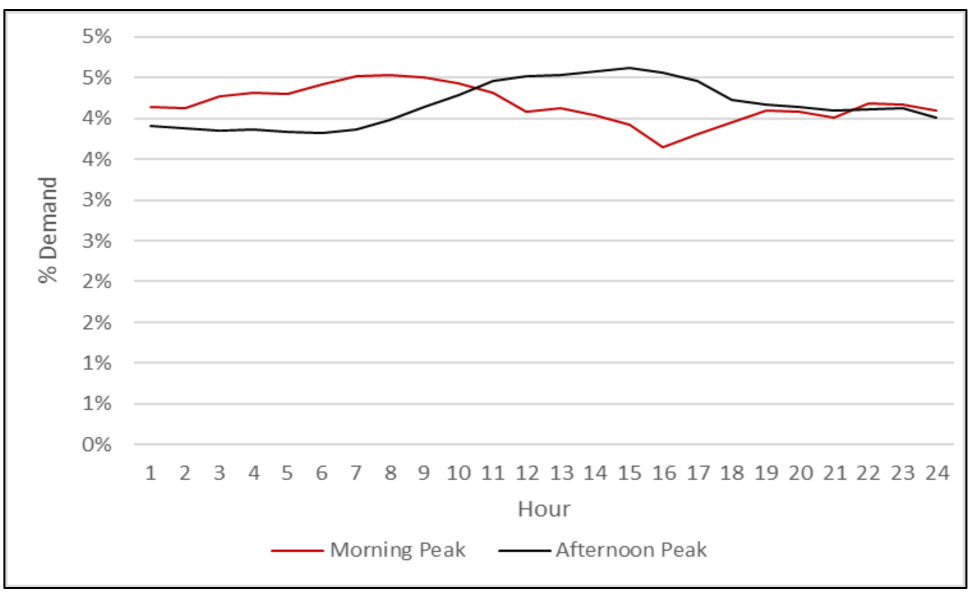


Figure 69. DEP Large C&I Morning Peak Exceeds Afternoon Peak by 10% – Average Season Peak Day

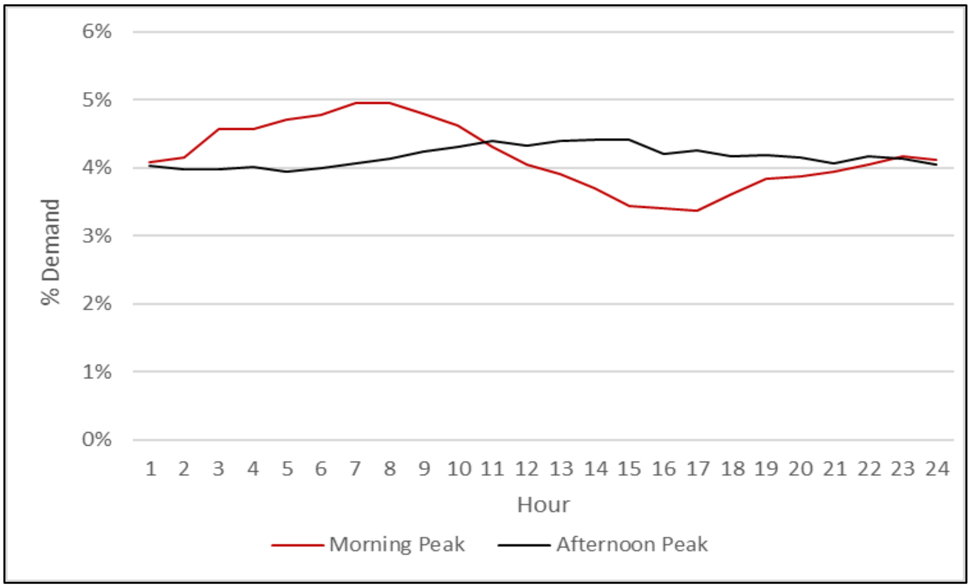
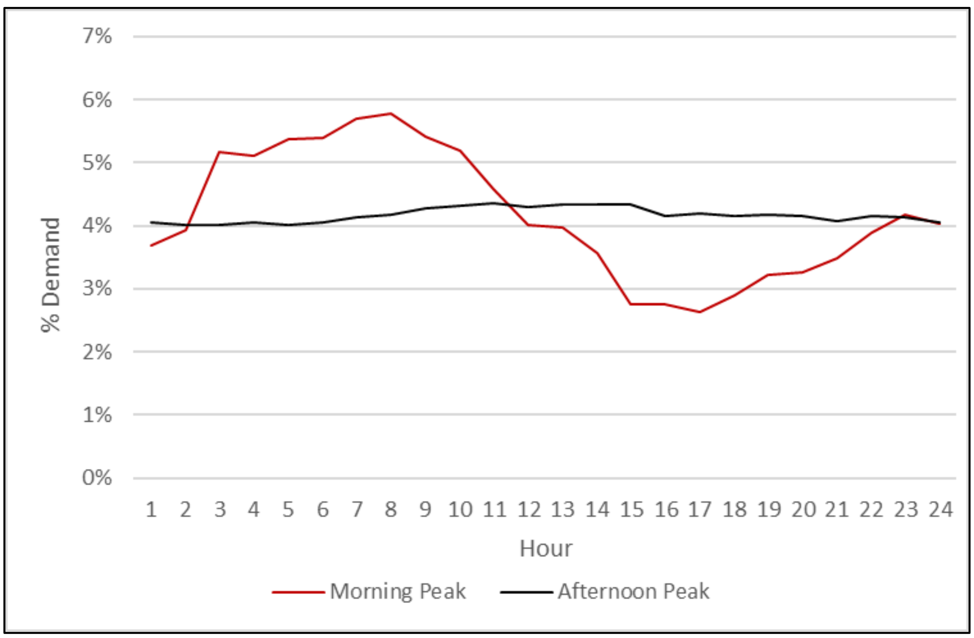


Figure 70. DEP Large C&I Morning Peak Exceeds Afternoon Peak by 20% – Average Season Peak Day



Market Characteristics

The following section discusses market characteristics of key drivers in C&I peak winter morning peak demand.

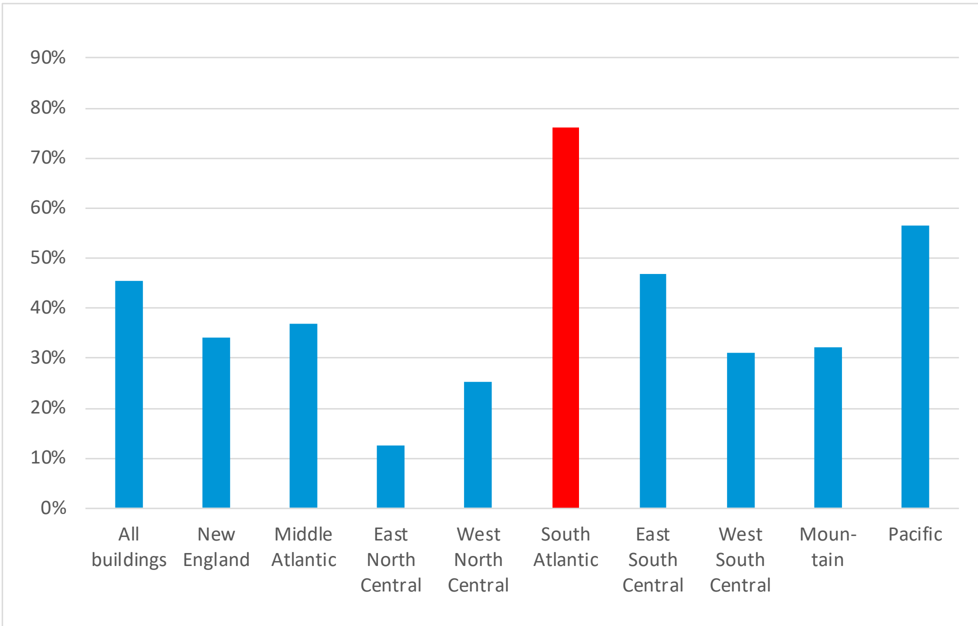
Space Heating

DEC and DEP are in the South Atlantic of the 2012 Commercial Buildings Energy Consumption Survey (CBECS). This survey, administered by the Energy Information Administrations (EIA)[38] indicates that heat

[38] Accessed April 2020 at https://www.eia.gov/consumption/commercial/

pumps are the primary space heating source in 77% of commercial buildings,[39] compared to approximately 60% of buildings nationally and as shown in Figure 68, this is the highest saturation of heat pumps in any CBECS region.

Figure 71. Heat Pump as Primary Commercial Heat Source by CBECS Region



To define how many buildings might be heated with heat pumps, we first used EIA to estimate the number of Duke commercial customers within the CBECS South Atlantic region, and Table 41 shows that 18% of the region's utility customers are Duke utilities in NC and SC.

Table 41. Distribution of Duke Commercial Customers in CBECS South Atlantic Region

Utility	Region			% of CBEC Region		
	System	SC	NC	SC	NC	System
DEC	375,072	94,117	280,955	3%	8%	11%
DEP	236,723	31,801	204,922	1%	6%	7%
Duke Total	611,795	125,918	485,877	4%	14%	18%

We applied these customer percentages to CBECS building counts to estimate the total number of DEC and DEP buildings heated with heat pumps, as well as tons of capacity, and technical demand[40] based on the following assumptions:

- We binned our saturation of heat pumps by building type based on average size and professional judgement, including:
    - 60% saturation for facilities under 12,000 sq. ft.
    - 40% for facilities under 20,000,
    - 20% for facilities larger than 200,000 sq. ft., with some adjustment for select segments, such as a lower saturation in large warehouses.

[39] This is saturation of building count, not saturation of square footage

[40] Defined as total demand if all systems are operating at the same time

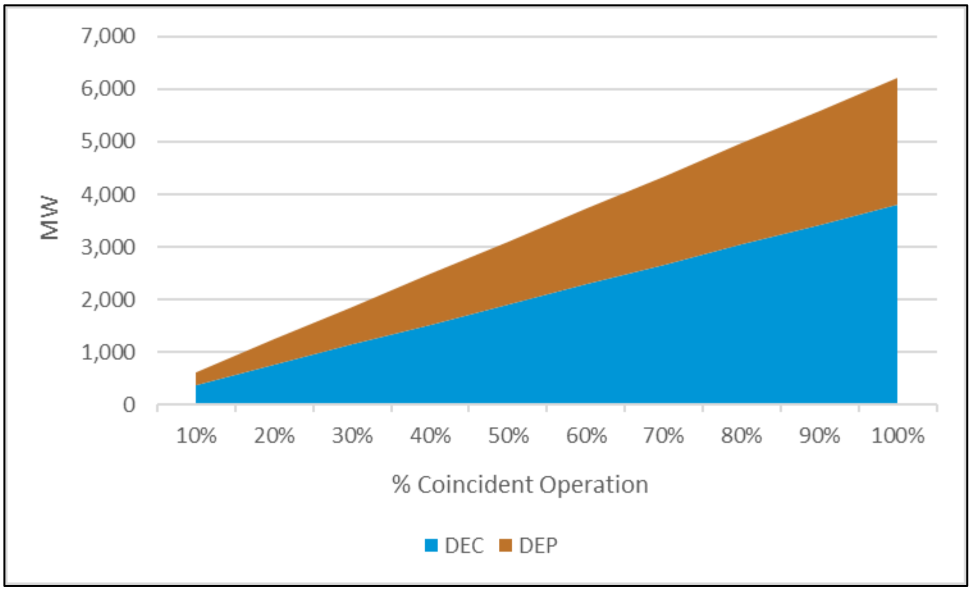
- 3.5 kW/ton
- 630 sq. ft./ton for all building type except for warehouse and storage, where we estimate 3,000 sq. ft. / ton

As shown in Table 42, based on the assumptions above our analysis indicates that approximately 78,000 buildings are heated with heat pumps in roughly 1,280 MM of conditioned space. This represents 2 million tons of capacity and a technical load of 6,207 MW. Based on our previous estimate that heat pumps account for 830 MW of load at hour 8:00 on our study peak day, as presented in the discussion preceding Figure 12, this implies an estimate coincident operation of about 13% across the C&I sector. We consider this reasonable because these systems are installed in a wide diversity of businesses with different operating schedules, structure types, commercial uses, and system duty cycles. Figure 69 shows our estimated system demand from commercial heap pumps at various levels of operating coincidence.

Table 42. Estimated Heat Pump Heating Technical Demand

Segment	Total Bldgs.	Heat Pump Bldgs.	Million Sq. Ft.	Tons	Technical MW
Education	15,414	6,166	201	318,671	1,117
Food sales	7,087	4,252	20	31,643	111
Food service	13,819	8,292	42	66,652	234
Health care Inpatient	253	51	14	22,722	80
Health care Outpatient	3,721	744	9	14,419	51
Lodging	5,847	3,508	129	204,836	718
Mercantile Retail (other than mall)	16,300	6,520	75	118,043	414
Mercantile Enclosed and strip malls	9,036	3,614	120	190,081	666
Office	35,080	7,016	113	178,579	626
Public assembly	7,973	3,189	64	101,436	355
Public order and safety	2,773	1,109	61	96,162	337
Religious worship	14,174	8,504	91	144,244	505
Service	17,717	10,630	79	124,719	437
Warehouse and storage	31,359	12,544	201	63,555	223
Other	3,012	1,807	60	95,601	335
Total	183,563	77,946	1,279	1,771,363	6,207

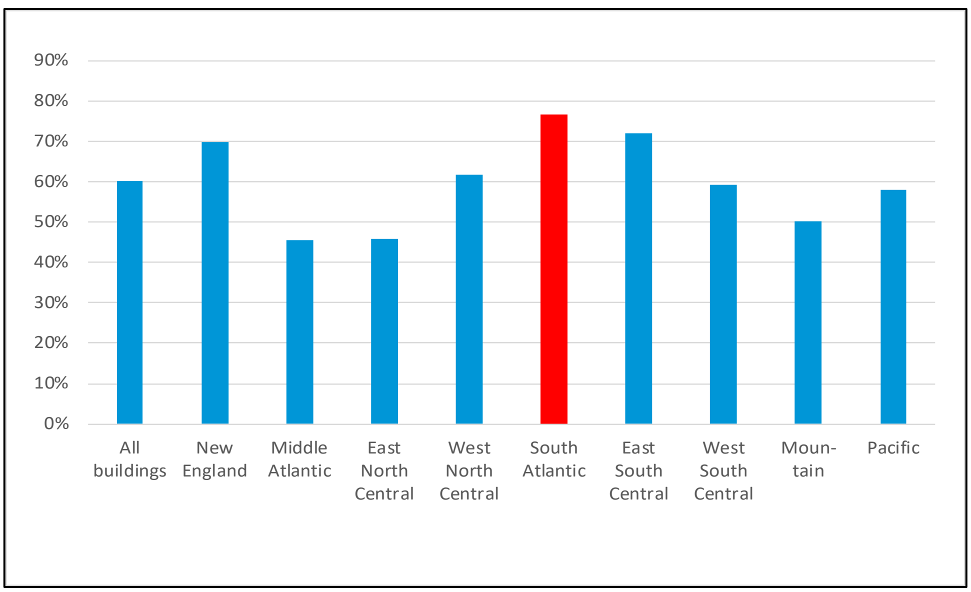
Figure 72. Commercial Heat Pump Operating Coincidence Demand



Hot Water Heating

Using the same CBES data discussed for heat pump space heating, Figure 70 shows that electric hot water heaters are their primary source of hot water for 78% of commercial buildings.

Figure 73. Electric Hot Water Heaters as Primary Commercial Source by CBECS Region



In addition to high saturation, the market appears to be shifting towards electric water heating in commercial applications. As discussed in an EIA technology forecast update, [41] Figure 71 shows that annual shipments of commercial electric water heaters have increased from 24,000 units in 1997 to about 128,000 units in 2017. This is in contrast with annual shipments of gas fired hot water heaters which has

[41] EIA -Technology Forecast Updates – Residential and Commercial Building Technologies –Advanced Case. Navigant April 2018

fluctuated between 80,000 units to 100,000 units annually during this same timeframe, as shown in Figure 72.

Figure 74. Commercial Electric Hot Water Heater Shipment Trends

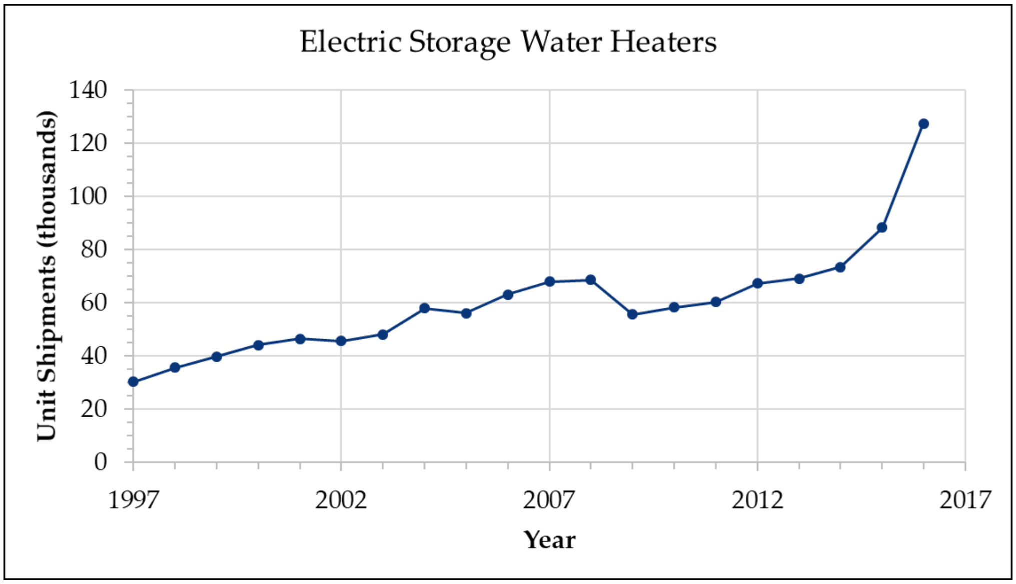
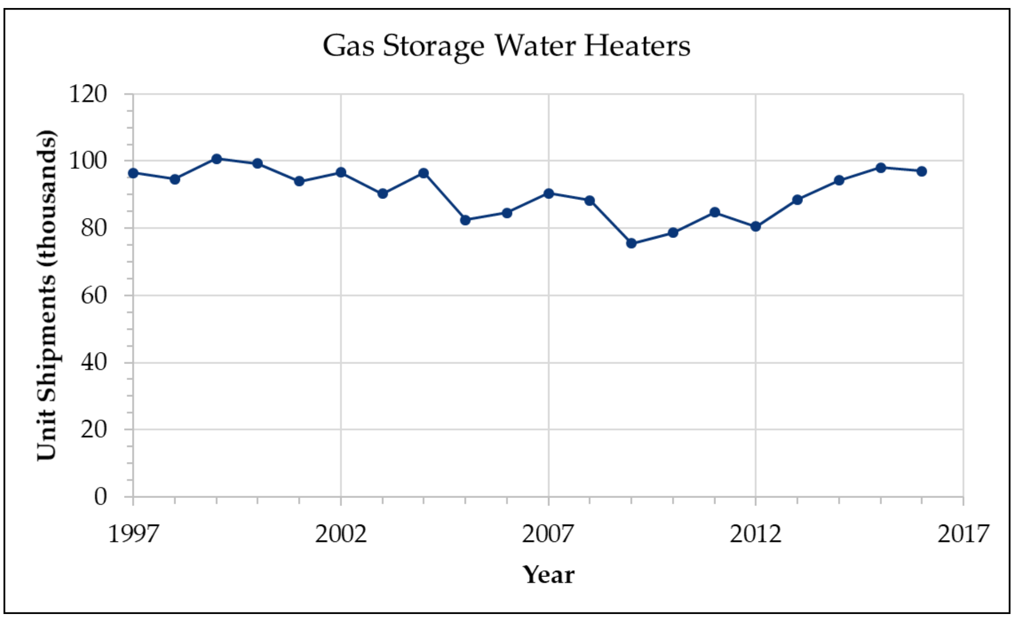


Figure 75. Commercial Natural Gas Hot Water Heater Shipment Trends



We estimated commercial electric hot water heating (CHWH) technical demand using the same approach as our analysis of commercial heat pump space heating. First, we estimated total building counts and assumed CHWH saturation by segment to define the number of buildings with CHWH consistent with CBECS regional estimates. We then used the following assumptions to estimate the number of CHWH units installed and the resulting technical demand[42]:

- Average commercial area per HWH = 10,000 sq. ft. for all building type except for warehouse and storage, where we estimate 1 HWH per building

[42] Defined as total demand if all systems are operating at the same time

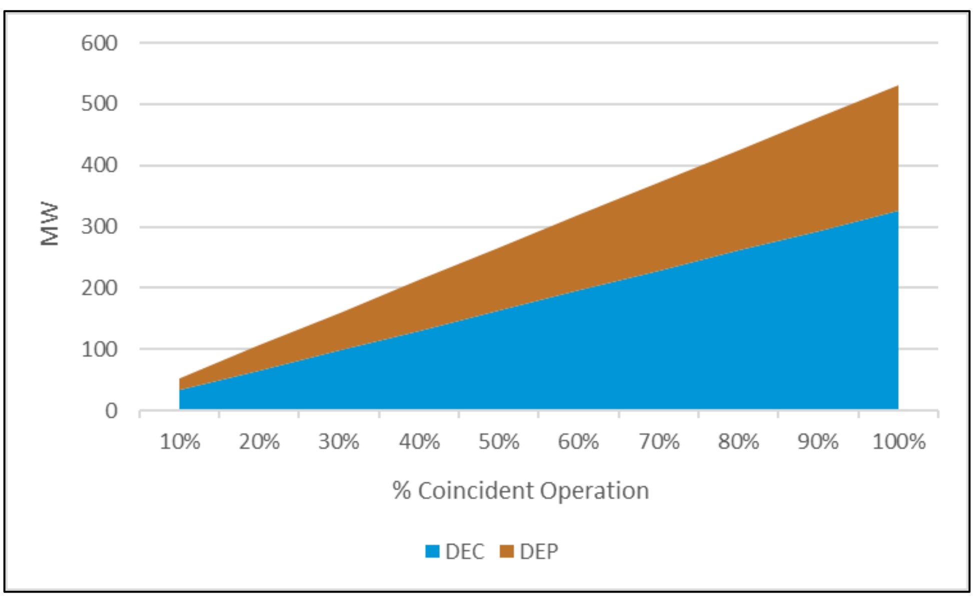
- Ratio of commercial CHWH heater size to average residential CHWH size = 2.38
- Average kW demand during winter morning peak period = 1.93 kW

As shown in Table 43, based on the assumption above our analysis indicates that approximately 132,000 buildings use CHWH tanks, totalling approximately 300,000 units, representing 532 MW of technical MW demand. Figure 73 shows our estimated system demand from commercial electric water heaters at various levels of operating coincidence.

Table 43. Estimated Electric HWH Technical Demand

Segment	Total Buildings	EHWH Saturation	EHWH Buildings	Ave Sq. Ft.	EHWH Units / Building	Total Units	Technical Demand (MW)
Education	15,414	60%	9,248	32,644	4	36,993	71
Food sales	7,087	40%	2,835	4,700	1	2,835	5
Food service	13,819	40%	5,528	5,077	1	5,528	11
Health care Inpatient	253	20%	51	283,500	29	1,468	3
Health care Outpatient	3,721	60%	2,232	12,238	2	4,465	9
Lodging	5,847	40%	2,339	36,879	4	9,355	18
Mercantile Retail (other than mall)	16,300	80%	13,040	11,435	2	26,080	50
Mercantile Enclosed and strip malls	9,036	80%	7,229	33,216	4	28,914	56
Office	35,080	80%	28,064	16,076	2	56,128	108
Public assembly	7,973	80%	6,378	20,089	3	19,134	37
Public order and safety	2,773	80%	2,218	54,753	6	13,311	26
Religious worship	14,174	80%	11,339	10,713	2	22,678	44
Service	17,717	80%	14,174	7,410	1	14,174	27
Warehouse and storage	31,359	80%	25,087	16,000	1	25,087	48
Other	3,012	80%	2,410	33,412	4	9,638	19
Total	183,563	72%	132,171	38,543	67	275,787	532

Figure 76. Commercial Electric HWH Operating Coincidence Demand



We did not pursue this as a solution set candidate based on several considerations, including:

- We are uncertain of commercial water heating duty cycle and could not define what percentage of technical load is coincident with winter morning peaks. We suggest this be a topic of any potential commercial end use study (CEUS).
- We consider that CBECS is a reasonable basis to estimate the number of buildings with CHWH but are uncertain about the number of units installed and distribution of tank sizes. We suggest this also be a topic of any potential commercial end use study (CEUS).
- We are not aware of any third-party DSM aggregators that are active in this market and that might be able to deliver a hot water solution like that proposed for the residential market. Aggregators would likely offer the most efficient method of capturing this potential. However, it is likely aggregators will enter this market because of its growth (Figure 71) and the technology solutions used in the residential market, either switch or rate enabled, are maturing and will be viable for commercial applications.

We consider this market worth monitoring because turnover of electric resistance hot water heaters is high, and volumes are large. Electric hot water heaters have an average useful life of around 10 years, indicating that around 27,000 units are replaced each year based on the estimated number of installed units defined in Table 43.

Solution Set Recommendations

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

- Bring Your Own Thermostat (BYOT) and Rate Enabled Thermostats (RET), collectively referred to as controlled thermostat measures.
- Automated Demand Response (ADR) for larger C&I flat rate customers selecting advanced rates
- Winter Heat Pump Tune-up (mention but need CEUS to forecast)

Like the discussion on the residential solution set, the following discussion provide a summary of these solutions and related modelling inputs that are explained more fully in the separate report on Task 4 of our scope, Prepare Winter Peak Targeted DSM Plan.

Bring Your Own Thermostat (BYOT) and Rate Enabled Thermostats (RET)

BYOT and RET would be implemented via the DEP EnergyWise for Business Programs[43]. We modelled the demand response for BYOT and RET as a single, combined impact and used common modelling inputs that have a similar operational sequence to the residential BYOT recommendation but have a slight variation in duration, including:

- 1-hour preheat beginning at hour starting 6:00
- 3-hour events from hour starting 7:00 through hour starting 9:00. We expect decreasing yields in hours starting 8:00 and 9:00
- 2-hour recovery from hour starting 10:00 through hours starting 11:00

During the 3-hour event, some systems will turn back on if the facilities cannot maintain an acceptable temperature and as such, savings degrade through hours starting 9:00, as shown in Table 44. After the event, a 1-hour recovery period is expected during which the heating system activates to return the indoor temperature to settings determined by the occupant. Our estimated max site yield is 2.88 and

[43] Listed as the SBEEDR program in the DSM snapshot presented in Table 3

2.90 kW for DEC and DEP respectively and assumes a 75% cycle based on the evaluation of the EnergyWise Business program.[44] We are aware of disappointing impact results defined in the SPEEDR evaluation but suggest that 1) customers on a TOU rate may be more amenable to a longer event duration and 2) any new program exclude 25% and 50% cycle options.

Table 44. Hourly Commercial BYOT and RET kW Impacts per Participant

Hour Starting	Impact Curve	DEC	DEP
5	0%	0.00	0.00
6	-82%	-2.36	-2.38
7	100%	2.88	2.90
8	55%	1.59	1.60
9	41%	1.18	1.19
10	-100%	-2.88	-2.90
11	-14%	-0.40	-0.41

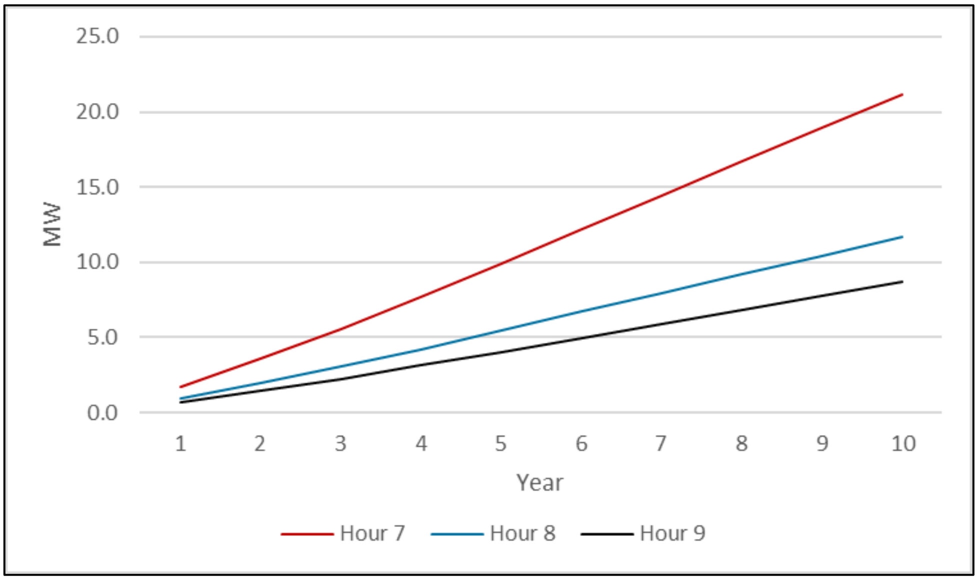
Figure 72 shows the forecast by hour over a 10-year horizon based on the following assumptions for the combined C&I BYOT and RET offering:

- 1st year market adoption of 1.00%
- Annual program growth 7%
- Operating coincidence 18%
- Starting year 1 participation: 2,624 HP units
- Start Year: Dec-20

As shown in Figure 74, at the end of a 10-year implementation period we expect a peak load shed capacity of approximately 21 MW during the hour starting at 7:00, declining to 8 MW by the hour starting at 9:00. The 1-hour preheat and 2-hour recovery period result in neutral energy use during the 6-hour total event.

[44] Duke Energy Carolinas and Progress EnergyWise Business Evaluation Report, Final. Opinion Dynamics, November 9, 2018

Figure 77. 10-Year Controlled Thermostat Savings Forecast by Hour



Automated Demand Response

As discussed in the solutions set defined for the large C&I market, Automated Demand Response (ADR) combines advanced rate design with technology to enable robust demand response. We consider this a viable solution for medium sized C&I customers and included the impacts for medium sized C&I participation in the ADR forecast provided for the large C&I segment.

Solution Set Measures Considered but Not Forecast

The following measures were considered for analysis but not pursued at this time.

1. Winter Heat Pump Tune-up. We expect that the same winter heating tune-up program being recommended for the residential market applies to the commercial market, though we did not analyze the potential because of uncertainty about the performance of installed commercial heat pumps.
2. Electric Hot Water Heating. As presented in the C&I Market Characteristics discussion, we consider the electric hot water heating market worth monitoring and recommend the following research:
   - Complete a CEUS defining:
     - Commercial water heating duty cycle and define the technical load that is coincident with winter morning peaks
     - Define segmentation including the number of units installed and the distribution of sizes across each segment
   - Complete an assessment of the market delivery capacity of local trade allies and distributors to deliver and install heat pump water heaters.
   - Identify any third-party DSM aggregators operating or emerging that will be delivering an integrated commercial water heater DSM solution.

6. Large C&I Market and Solutions

Rate Definitions

For this analysis, we define the large C&I segment as high demand customers participating in DEC's optional TOU and DEP's RTP rates. Some of the solutions presented here may also apply to medium sized C&I costumers and the rates we defined for this segment in section 5 at Table 36. During the average winter peak day in 2018, large C&I customers accounted for about 32% of combined DEC and DEP system demand. Table 45 provides a summary rates for the large C&I sector and shows that during our study peak day event DEC customers account for 86% of large C&I demand while DEP customers account for the remaining 14%.

Table 45. Large C&I Rates Summary

System	Schedule	Tier Type	On Peak	Winter	Study Peak Day MW	% Load	KW Cap
DEC	OPT-E (NC - Pilot)	On/Off kWh	6:00 a - 1:00 p	Oct – May	4,232	86%	Tiered
	OPT-V (NC)	On/Off kWh and KW	6:00 a - 1:00 p	Oct – May			
DEP	LGS-RTP-58	RTP Hourly Energy Charge	None	None	668	14%	>1,000

Peak Load Profile

The following section provides observations for DEC and DEP load profiles based on a review of 8,760 hourly load data for the C&I rates defined in Table 45. The analysis of DEC optional TOU rates (OPT-E and OPT-V (NC) in Table 45) have been refined to disaggregate between commercial (Opt-C) and industrial (Opt-I) TOU customers.

DEC

Figure 75 compares the average demand from Opt-C and Opt-I for the 6 winter and 4 summer peak events in 2018 and shows a relatively constant profile, with increased usage in the summer likely due to 1) increased air conditioning loads, and 2) increased process loads, such as increased water transfer. The limited winter peak indicates that many of these customers have access to natural gas for heating. Figure 76 separates Opt-C and Opt-I for the 6 winter events and shows a difference in profiles such that Opt-C more closely resemble a commercial profile. We note that, in aggregate, these facilities have long run hours, maintaining a near constant load throughout the average winter peak day.

Figure 78. DEC 2018 Large C&I – Average Season Peak Day

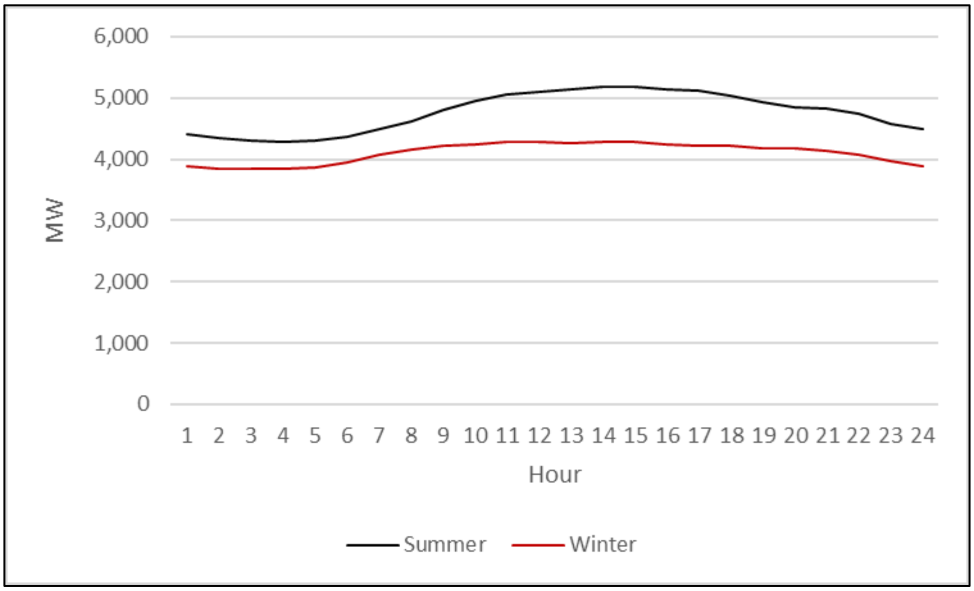


Figure 79. DEC 2018 Large C&I - Study Peak Day

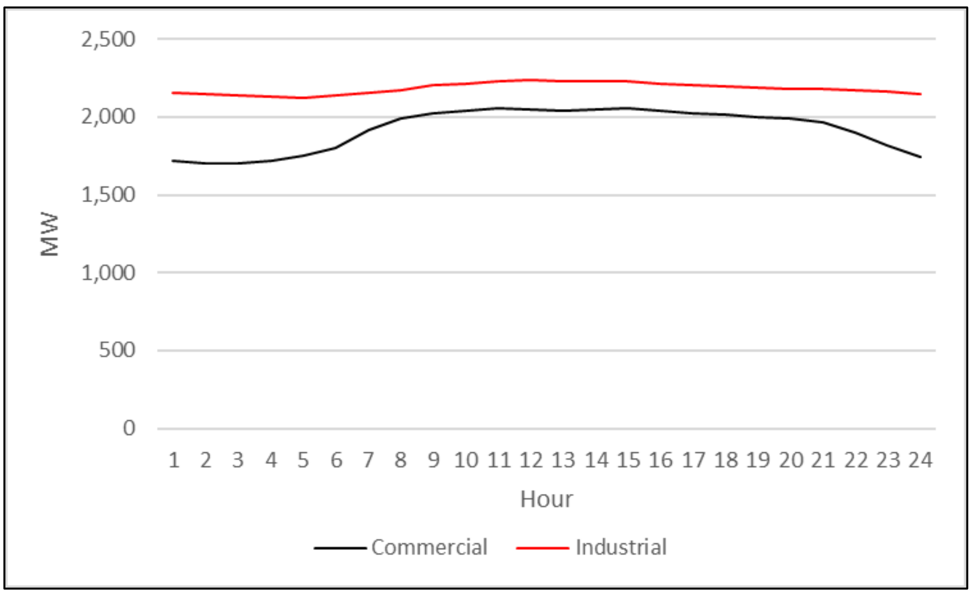


Figure 77 looks at the study peak day and adjusts the scale to emphasize the difference in load shapes between commercial and industrial TOU customers. We analyzed the underlying data and estimate that the heating load attributable to Opt-C customers is 155 MW by comparing average demand of 2,108 MW during the hours ending 7 through 9 with the average demand for hours ending 1 through 6 and 10 through 24 (1,947 MW across all non-peak hours), as shown in Table 46.

Table 46. DEC Optional TOU Commercial Demand – Study Peak Day

Time Period	Average MW
Hour ending 1 through 6 and 10 through 24	1,947
Hour ending 7 through 9	2,103
Difference	155

Figure 80. DEC C&I Optional TOU Rate Demand by Segment – Study Peak Day

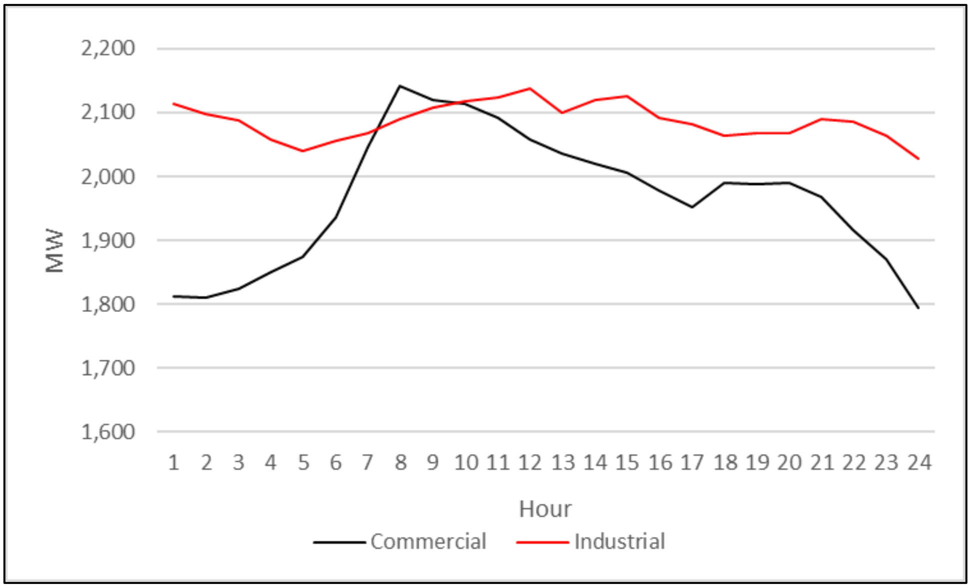


Figure 77 compares demand between the study peak day and the average winter peak days for Opt-C customers, showing a difference of about 130 MW between hours 7:00 and 8:00, indicating that these customers have demand associated with heating that is moderately sensitive to weather events.

Figure 81. DEC Optional Commercial TOU Rate Demand – Study Peak Day Vs. Average Winter Peak Day

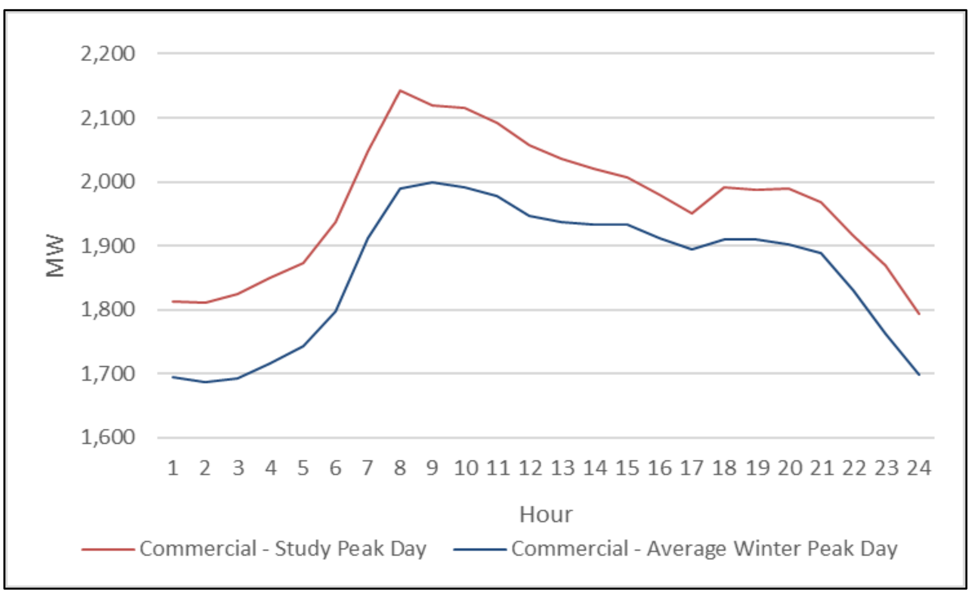
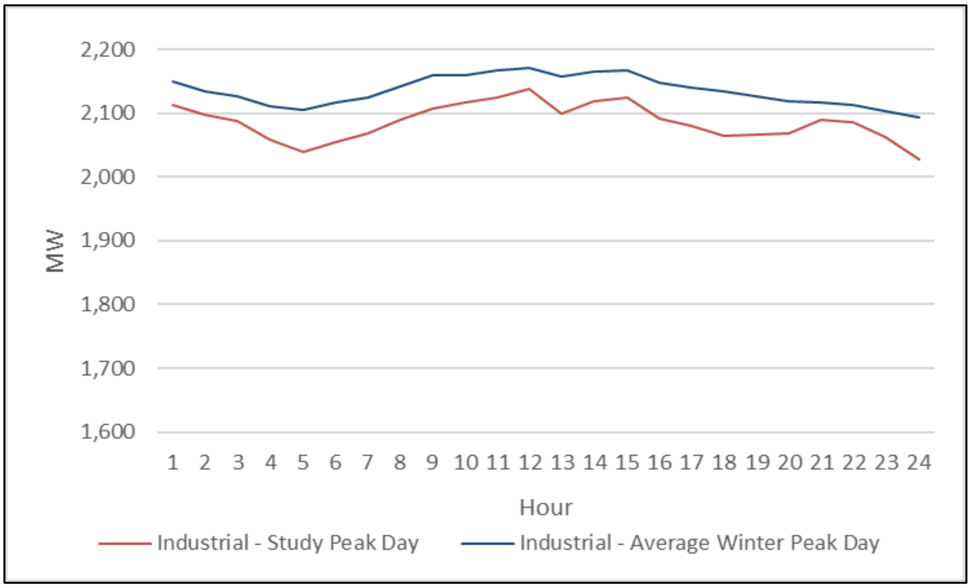


Figure 77 compares demand between the study peak day and the average winter peak days for Opt-I customers, showing slightly lower usage during our study peak day when compared to the average winter peak day, indicating that these customers may not be sensitive to weather events.

Figure 82. DEC Optional Industrial TOU Rate Demand – Study Peak Day Vs. Average Winter Peak Day



DEP

No segmentation data was provided for the LGS-RTP-58 rate and thus we were unable to compare industrial and commercial customers. As observed for the DEC optional TOU customers, Figure 79 shows an increase in summer demand most likely related to commercial AC loads and industrial production.

Figure 83. DEP 2018 Large C&I – Average Season Peak Day

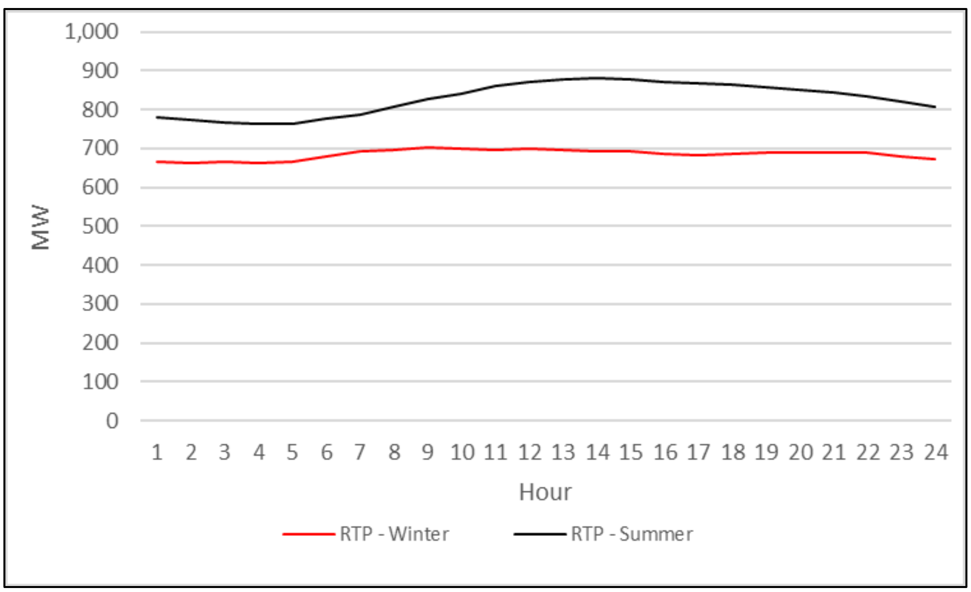


Figure 80 looks at the study peak day and adjusts the scale to emphasize the load shape profile during our study peak day, showing peak demand between 7:00 a.m. and 11:00 a.m., indicating some heating load. Like DEC, we analyzed the data underlying Figure 80 to define a heating load of 41 MW as shown in Table 47 .

Figure 84. DEP 2018 RTP Demand – Study Peak Day

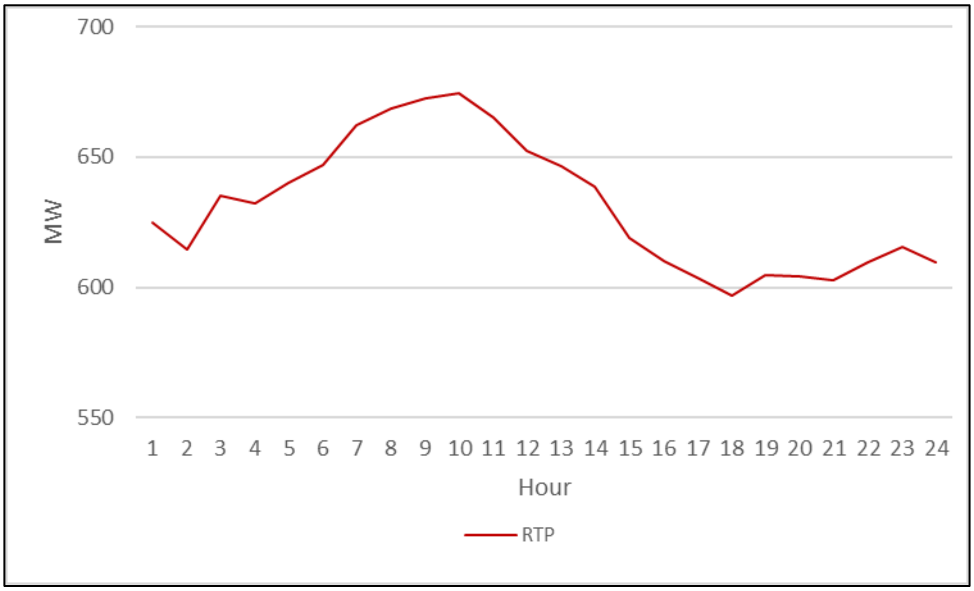


Table 47. DEP RTP Demand – Study Peak Day

Time Period	Average MW
Hour ending 1 through 6 and 10 through 24	626
Hour ending 7 through 9	668
Difference	41

Market Characteristics

Because we have limited segmentation data, our capacity to characterize the large C&I market is limited to interpreting information from various secondary sources. Table 48 provides an additional analysis of CBECS building population data first presented in Table 42 to estimate the number of large C&I buildings. It estimates that the number of buildings larger than 30,000 sq. ft. which would be applicable to large C&I solutions is approximately 57,000 across both utilities. This analysis excludes market segments where it is unlikely that any building would exceed 30,000, such as restaurants. As discussed at Figure 75, many of these buildings will be heated with natural gas, but all have curtailable winter loads from lighting and HVAC ventilation systems, with additional AC loads available in the summer.

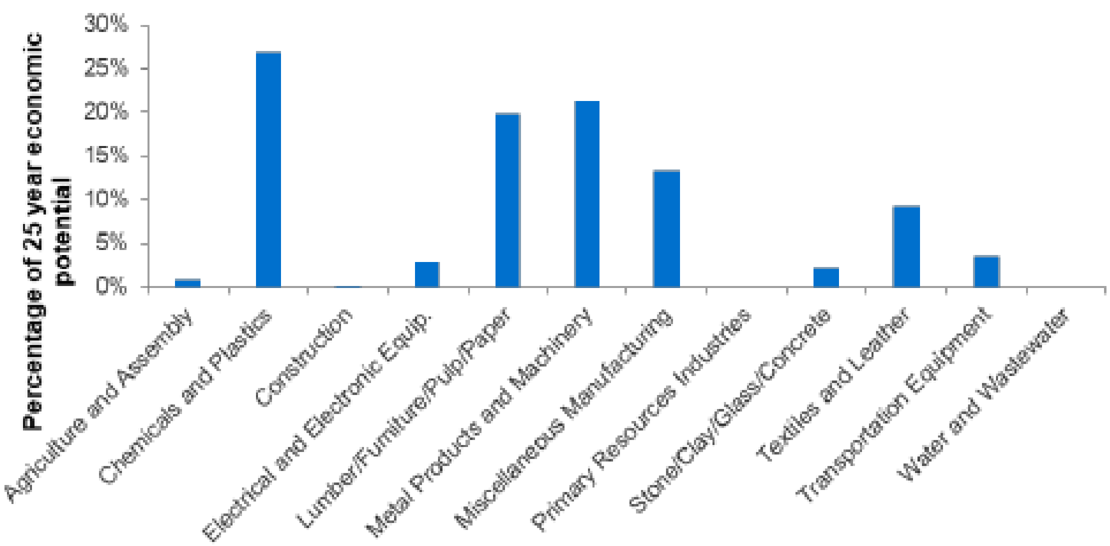
Table 48. Estimated Population of Large Buildings by Segment

	Total Buildings			Buildings > 30,000 sq ft		
Segment	DEC	DEP	Total	DEC	DEP	Total
Education	9,450	5,964	15,414	4,725	2,982	7,707
Food sales	4,345	2,742	7,087	434	274	709
Health care Inpatient	155	98	253	109	69	177
Health care Outpatient	2,281	1,440	3,721	456	288	744
Lodging	3,584	2,262	5,847	1,792	1,131	2,923
Mercantile Retail	9,993	6,307	16,300	1,999	1,261	3,260
Mercantile Enclosed Mall	5,540	3,496	9,036	2,770	1,748	4,518
Office	21,506	13,574	35,080	10,753	6,787	17,540

Public assembly	4,888	3,085	7,973	2,444	1,542	3,986
Public order and safety	1,700	1,073	2,773	1,020	644	1,664
Warehouse and storage	19,225	12,134	31,359	7,690	4,854	12,544
Other	1,847	1,165	3,012	923	583	1,506
Total	112,537	71,026	183,563	35,115	22,163	57,278

For industrial loads we reviewed the Nexant Market Potential Study[45], and Figure 82 and Figure 83 show energy efficiency potential by industrial segment for DEC NC and DEP SC. Segment potential varies by state and system but can be viewed as a reasonable proxy indicator of segment level demand sources in the industrial market because, in general, all segments have similar equipment and energy efficiency potential. For example, Figure 84 shows energy efficiency potential by end use for DEP NC, and this distribution is consistent across the MPS studies for both states and utilities. Because energy efficiency potential in the industrial sector is also an indicator of the primary sources of load, Figure 84 indicates that demand response potential is most likely concentrated in motors, pumps, and HVAC systems (which we interpret to include refrigeration).

Figure 85. DEC NC Industrial EE Economic Potential by Segment[46]



[45] Duke Energy North Carolina EE and DSM Market Potential Study, Nexant, May 2020
[46] Duke Energy NC Carolina EE and DSM Market Potential Study. Nexant, May 2020. Figure 6-5: DEC Industrial EE Economic Potential by Segment

Figure 86. DEP SC Industrial EE Economic Potential by Segment[47]

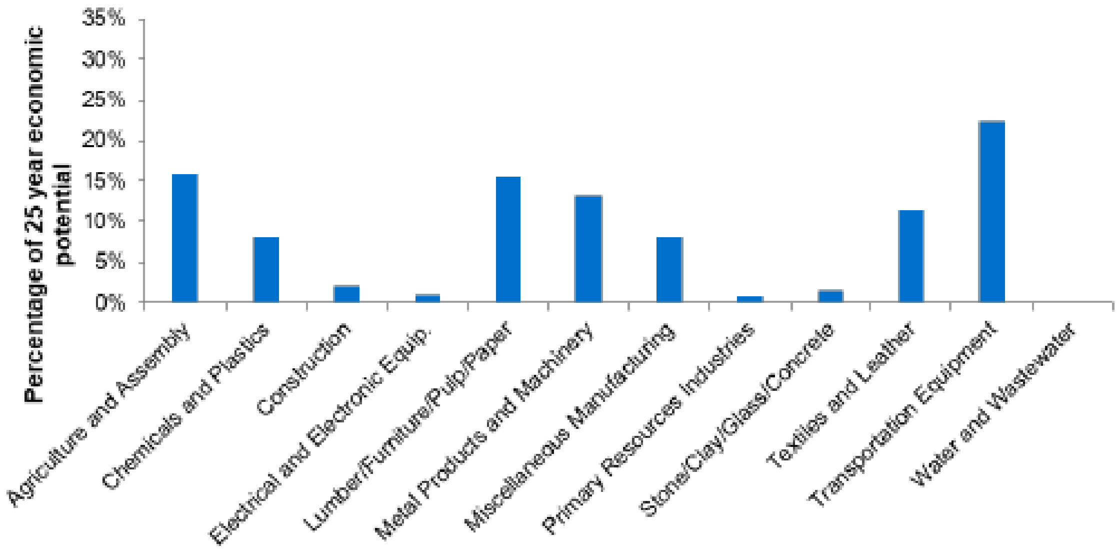
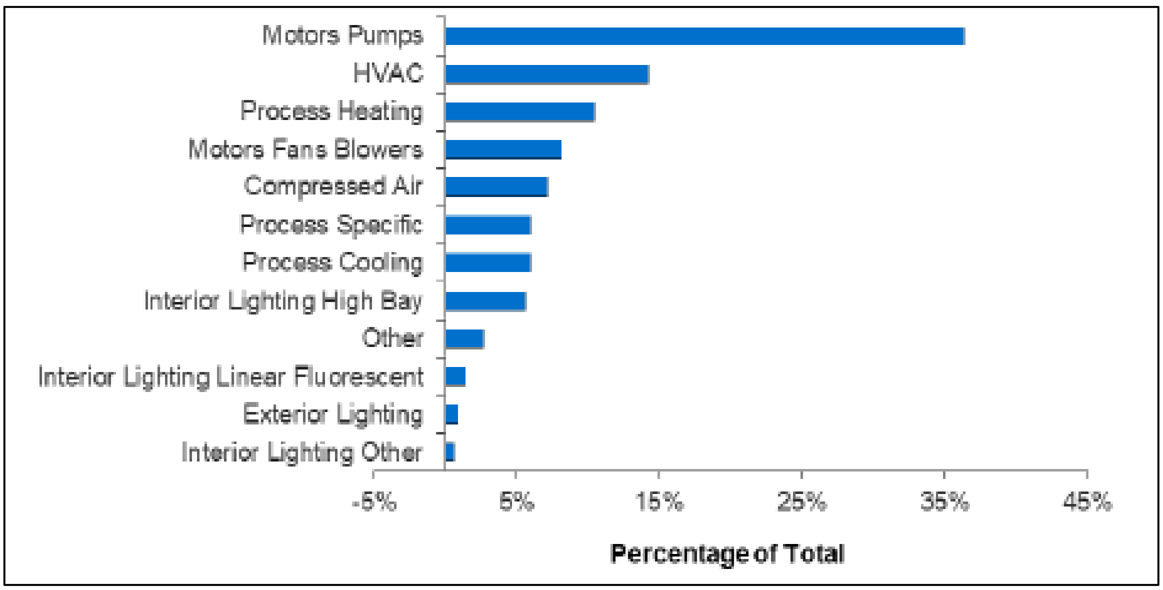


Figure 87. DEP NC Industrial Baseline Load Shares[48]



Solution Set Recommendations

Based on the preceding discussion, the following provides key recommendations for the large C&I solution set.

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[47] Duke Energy SC Carolina EE and DSM Market Potential Study. Nexant, May 2020. Figure 6-10: DEP Industrial EE Economic Potential by Segment

[48] Duke Energy North Carolina EE and DSM Market Potential Study. Nexant, May 2020. Figure 3-12: DEP Industrial Baseline Load Shares

ADR Program Concept

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

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

The following describes an Automated Demand Response (ADR) program (Program) structure that we expect is applicable to medium and large C&I programs in the Carolinas and which is based on programs in operation in California's three electric investor-owned utilities[49] since 2014. The objectives of the Program, as discussed in more detail further in the document, include:

- Fill gaps in the current C&I DSM offering
- Diversify the DSM resource mix and improve reliability
- Reduce opt-outs by expanding the DSM value proposition
- Reduce participant attrition
- Leverage emerging Duke data infrastructure to manage DSM operation costs
- Increase DSM cost recovery
- Expand both summer and winter demand response capacity
- Provide a pathway for emerging technology adoption

For background, California's ADR programs are locationally dispatchable and involve a combination of innovative rates, programs, and technology solutions where customers may choose from among different options designed to fit their needs. The intent of the ADR solution is to provide the utilities with 1) the kW for projects receiving ADR incentives to be as realistically achievable as possible, and 2) customers that will participate consistently in as many DR events as possible. Below are rates and program solutions that California ADR customers may participate in, by utility:

Pacific Gas and Electric (PG&E)

- Peak Day Pricing (PDP) Tariff / Rate
- Capacity Bidding Program (CBP)
- Demand Bidding Program (DBP)

Southern California Edison (SCE)

- Real Time Pricing (RTP) Tariff / Rate
- Critical Peak Pricing (CPP) Tariff / Rate
- Demand Bidding Program (DBP)
- Aggregator Managed Portfolio Program

[49] Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E)

- Capacity Bidding Program (CBP) Program
- Demand Response Auction Mechanism (DRAM) Pilot DR Program

San Diego Gas and Electric (SDG&E)

- Peak Time Rebate (PTR) Tariff / Rate
- Base Interruptible (BIP) Program
- Capacity Bidding (CBP) Program

Regarding technology solutions, participants must have, or install, equipment that can be controlled remotely, such as an EMCS or other control. The ADR programs provide incentives and technical assistance for medium to large nonresidential customers to install and/or program equipment at the customer's facilities. The objective of this program is to enable the execution of a sequence of steps at the facilities to curtail electrical load after receiving a communications signal from the utility via the OpenADR communications protocol with the objective of maximizing the reliability and consistency of available kW capacity. In general, business customers can choose from equipment incentives that enable the following DR strategies:

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

The ADR program requires that customers have an OpenADR 2.0 A or B certified virtual end node (VEN) on site that pulls the automated DR event signal directly from a utility or aggregator. The ADR architecture consists of two major elements built on an open-interface standards model called OpenADR. First, the Demand Response Automation Server (DRAS) provides signals that notify electricity Participants of DR events. Second, a VEN or client for each Participant's site continually communicates with the DRAS and is linked to existing preprogrammed DR strategies independent of control network protocols such as BACnet or Modbus. Legacy ADR control systems used a VEN called a Client and Logic with Integrated Relay (CLIR), but these devices are no longer manufactured.

During a DR event with fully automated DR, the facility equipment receives a signal from the utility directly, and executes load shed strategies without Participant intervention. The technology solution consists of an open, interoperable industry standard control and communications technologies designed to work with both common energy management control systems and individual end-use devices. The technologies include a communications infrastructure via a computer server that sends DR signals to PG&E's Participant sites where load reductions are automatically implemented through building control systems. The technology and communications infrastructure used in ADR originated from an initial conceptual design developed in 2002 at Lawrence Berkeley National Laboratory (LBNL). ADR is a fully automated DR system using Client/Server architecture and is intended to replace labor-intensive manual and semi-ADR.

Objectives

The ADR program concept applied to the Carolinas is intended to address the following objectives.

Fill Gaps in the Current C&I DSM Offering

This program focuses more on the commercial segment where most controllable loads are HVAC and lighting related much of which is coincident with system peak. As shown in Figure 84, demand from commercial customers on the optional TOU rates (Opt-C) are about 90% coincidence in the 7:00 to 9:00 a.m. system peak timeframe.

These C&I lighting and HVAC assets are not present in the current DSM portfolio. At present, the bulk of system C&I DSM capacity is associated with 1) process related curtail at large industrial customers and 2) the use of customer owned backup generation during peak events as shown in Table 49. Most of this current capacity can be associated with industrial customers, such as DEC the optional TOU rates for industrial customer (Opt-I), also shown in Figure 84.   The proposed ADR program will address this gap by targeting commercial lighting and HVAC assets.

Figure 88. DEC 2018 Optional TOU Prototype Winter Event Demand by Segment

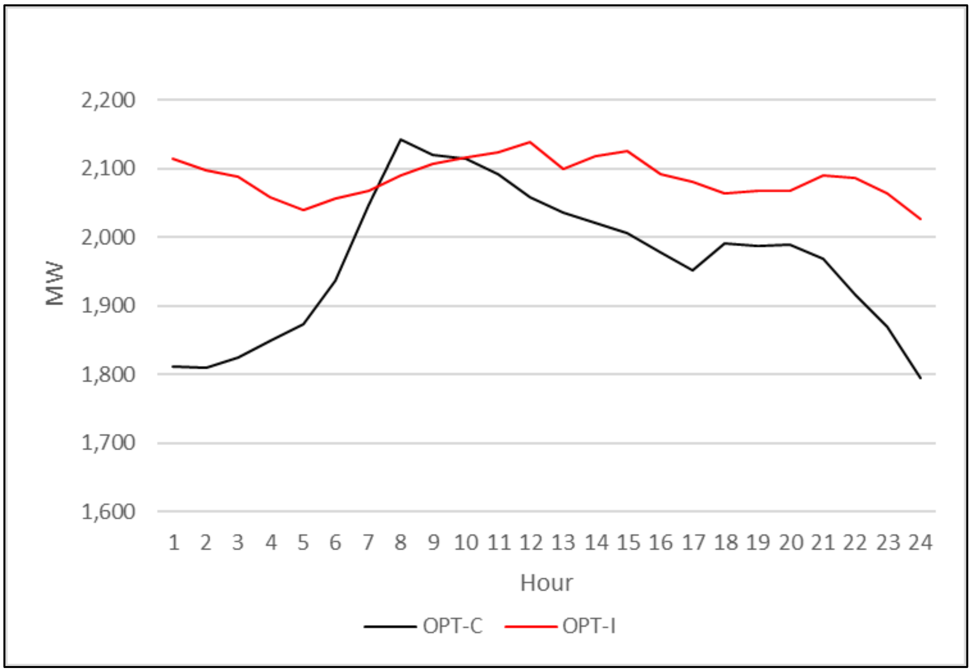


Table 49.DSM Capacity for PS and DRA

Primary Load Reduction Source	Participants	Capacity (MW@mtr) Summer	Capacity (MW@mtr) Winter	Ave Winter MW / Part
PowerShare				
Generator	55	66.9	67.3	1.2
Process	109	281.4	261.3	2.4
HVAC/Lighting	0	0.0	0.0	0.0
PowerShare Total	164	348.3	328.6	2.0
DRA				
Generator	41	16.6	11.7	0.3
Process	36	8.5	3.0	0.1
HVAC/Lighting	11	0.7	0.0	0.0
DRA Total	88	25.8	14.7	0.2
Combined				
Generator	96	83.5	79.0	0.8
Process	145	290.0	264.3	1.8
HVAC/Lighting	11	0.7	0.0	0.0
Combined Total	252	374.1	343.2	1.4

Diversify and Expand the DSM Resource Mix

Our expectation is that DSM based on a portfolio of distributed HVAC controls (and other non-process related loads) will present a larger population of candidate sites and more consistent response than generation and process related resources currently distributed across a small number of customers. Table 50 shows approximately 100% of DSM capacity is associated with generators and process curtailments from 252 DRA and PS customers defined in Table 49. Table 51 shows our preliminary estimate of 26,000

ADR viable sites[50] out of a total 66,000 customer sites across various rate classes reviewed, which forms the basis of an ADR solution focusing on EMCS controls, which currently make up less than 0.2% of combined PS and DRA capacity.

Table 50. PowerShare and DRA Capacity Allocation by Load Reduction Source[51]

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

Table 51. Estimate of ADR Viable Customers by Rate Class

OPCO	Rate	Customers		
		Total Customers	% Viable	Viable Customers
DEC	LGS	11,431	40%	4,572
	OPTC	21,133	40%	8,453
	OPTI	1,642	10%	164
DEP	MGS	32,108	40%	12,843
	LGS	345	40%	138
Total		66,659	39%	26,171

Expanding the DSM Value Proposition

Based on data provided by Duke, Table 52 provides our analysis of EE/DSM opt-out rates for various DEP rate classes. This data indicates that a large number of medium sites may be available for an ADR solution, but for most there is currently no viable DSM option because most will not have backup generation capacity, which is the only way they could meet the DRA and PS curtailable load thresholds.

We're uncertain why opt-out rates are so high for larger customers, but this may indicate that the current DSM offerings are not attractive and that combining Advanced Rates with technology solutions may provide a more attractive offer for some of these customers. The value proposition for an ADR solution will likely vary by market segment, and this should be reviewed and defined. For example Appendix 1, Public Segment DSM Value, provides an overview of the value on DSM in the public market segment and how ADR could be leveraged in this market, and Appendix 2, Water Treatment Segment DSM Value, discusses how DSM is applied in the water treatment market and indicates how ADR might be applied to existing SCADA systems at these facilities.

Table 52. DEP Opt-out by Rate Class[52]

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

[50] Customers over 30,000 sq. ft. controllable via access to EMCS system
[51] KEY FILE - PowerShare and DRA Participant Info - July 2020 2020.07.07
[52] KEY FILE - DSM EE Opt Out_Apr20_Floyd (version 1).xlsb

LGS-RTP	90	80	113%

Reduce Participant Attrition

Between 2015 and 2020, many of Duke's DSM solutions have experienced attrition, including:

- Many of Duke's legacy DSM programs, such as Large Load Curtailable, have seen decreases in available load for various reasons such as decreasing textiles industrial base or dropping off the programs because of difficulty curtailing production related loads during extended events.
- Between 2015 and 2020, PS and DR have seen 140 MW of attrition, resulting in a net decrease of 24 MW after new additions are considered. This includes 59 MW of capacity lost due to shifts in EPA rules regarding the use of backup generation for grid dispatch purposes, as shown in Table 53.

Table 53. Summary of DRA Participation by Sector[53]

Program	PS	DRA
Total 6-Year MW Attrition	(130)	(10)
Net 6-year MW Attrition	(31)	7
6-year EPA MW Attrition	(49)	(10)
EPA Attrition	44%	72%
Non-EPA Related Attrition	56%	28%

We expect that providing ADR solutions that leverage automated EMCS controls will have low attrition rates because they will have minimal, if any, impact on operations beyond slight adjustments to HVAC and lighting loads. Additionally, they will not have an impact on production related machines and are unlikely to be subject to any future EPA, or other, regulatory action.

Leverage Emerging Duke Data Infrastructure to Manage DSM Operation Costs

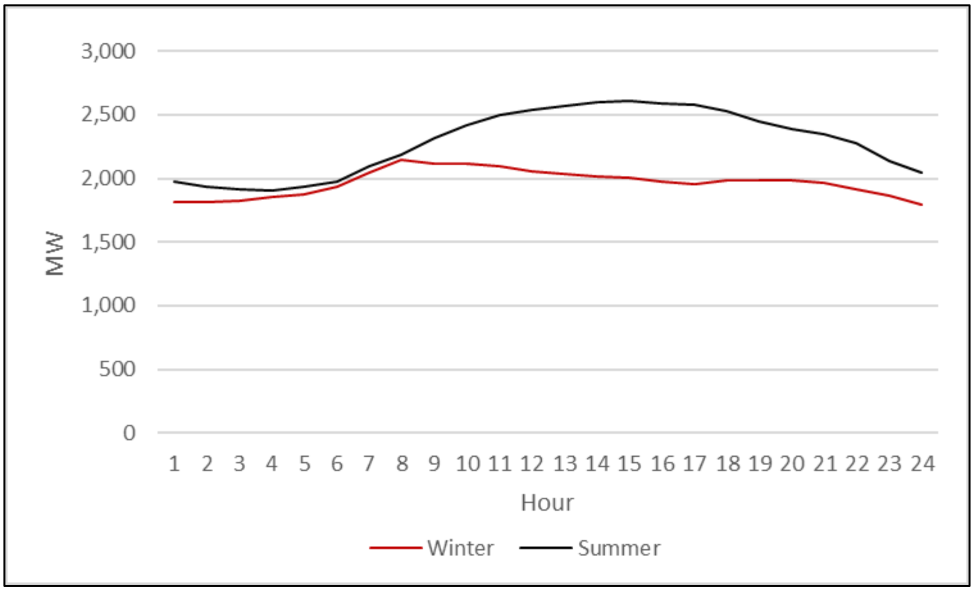
The proposed ADR design leverages Duke's expanding AMI and CIS/customer analytic capacity. This may help lower program costs in several ways, thereby enhancing cost effectiveness, including reducing the cost of identifying high potential sites and the use of normalized metered energy consumption to reduce EM&V costs.

Expand Both Summer and Winter Demand Response Capacity

The technologies associated with ADR are applicable to both summer and winter peak events. For example, while our efforts have focused on winter peak, Figure 86 shows that summer peak for the DEC commercial customers on optional TOU rates is more pronounced, likely because many of these customers have natural gas heating, but all will have electric powered mechanical cooling systems. The objective of developing EMCS systems for winter peak ADR will likely have a larger impact on summer DR capacity. Based on Figure 86, we anticipate that summer ADR potential related to EMCS impacts on air conditioning will be roughly 40% higher than winter heating potential.

[53] 2016 EM&V Report for the Duke Energy Progress Commercial, Industrial, and Governmental Demand Response Automation (DRA) Program. Navigant. June 19, 2017

Figure 89. DEC 2018 Optional TOU Demand for Average Season Peak Events



Provide a Pathway for Expanded Use of Existing and Emerging Technologies

ADR programs offer opportunities to deploy DR-focused emerging technologies that might be applicable to the Carolinas that are not currently represented in Duke's solution portfolio, including technologies defined in SDG&E Demand Response Emerging Technologies Program:[54]

1. **Battery Powered Load Shedding System.** The objective of this study is to evaluate the DR capability of the Energy Storage System (ESS). In addition to peak load shaving capability, the study will evaluate the impact of the energy storage system on the circuit and analyze customer bill/economic impacts.
2. **Vehicle to Grid Integration Platform (VGIP)**. The purpose of VGIP is to create requirements and use cases for a unified grid services platform that is secure, low cost, and an open platform. It will also aide in the development of architecture and functionality of the VGIP including OpenADR2.0b, SEP, and Home Area Network (HAN). Additionally, this project will assess performance of the VGIP against utility requirements through field tests and trials. BMW, Chrysler, Ford, GM, Honda, Mercedes, Mitsubishi, Nissan, and Toyota have agreed to be study participants.
3. **Demand Response with Variable Capacity Commercial HVAC System**s. Variable Capacity systems, with their onboard instrumentation and communications capabilities, are candidates for implementing both EE and DR measures at the same time. Efficiency rebates have been in place for such equipment in certain areas, but DR capabilities can push the technology further into the mainstream market, which is dominated by rooftop units, split systems and chiller/boiler combos. Commercial HVAC systems being a coincident load (peak power draw occurs during the hottest days) is a prime candidate for DR solutions besides being an efficient technology during normal operation.
4. **Permanent Load Shifting Evaluation of a Refrigeration Battery**. The Project will demonstrate the Refrigeration Battery's ability to maintain the desired temperature set-points of a supermarket's medium temperature refrigeration systems without running the central compressors or condensers for up to 8 hours at a time. By turning off medium temperature refrigeration compressors and

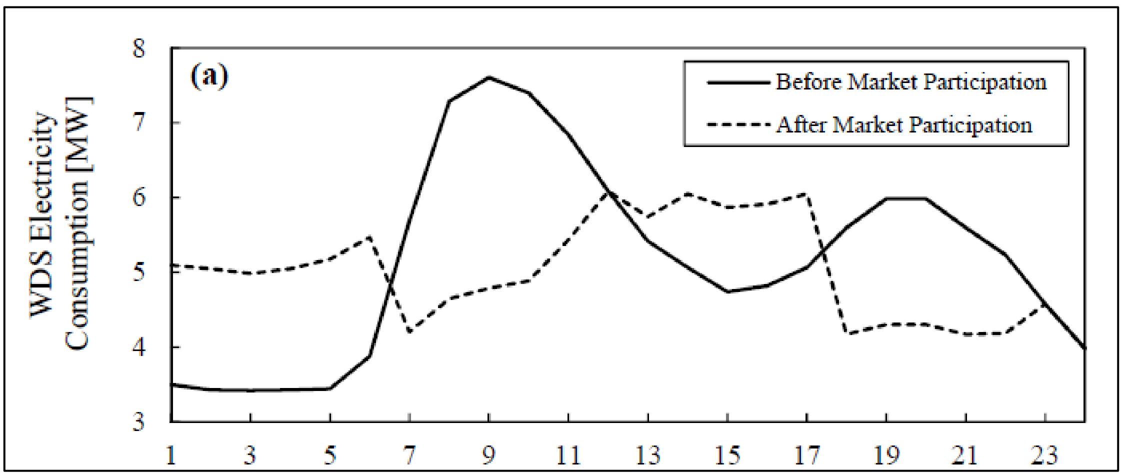
[54] 2018 SDG&E Demand Response Emerging Technologies Program semi-annual report accessed June 2020 at https://www.sdge.com/sites/default/files/regulatory/SDGE%20Semi%20Annual%20DR%20Emerging%20Tech%20Report%202018Q3.pdf

condensers during "on-peak" hours, as defined by SDG&E's AL-TOU rate schedule, the Refrigeration Battery is expected to reduce the facility's monthly peak demand by up to 75 kW. If successful it would achieve a decrease in monthly peak demand of up to 25%.

In addition to emerging technologies, ADR solution may provide for expanded opportunities with existing customers, for example:

- While much DSM was lost in the water treatment sector due to changes in EPA regulations, studies have identified substantial DR capacity by modifying pump schedules to maximize DR and economic value, much of it occurring during morning peak periods as illustrated in Figure 87.[55] ADR potential in this sector would be achieved by integrating ADR operations with existing Supervisory Control and Data Acquisition (SCADA) systems in place at each water treatment facility. Our preliminary research identified 210 water treatments in NC and SC which may be candidates. Past DSM efforts at these facilities focused on accessing back-up generation capacity only, while integrating pump loads provides a separate opportunity that is unlikely to be impacted by EPA regulations.

Figure 90. Example of Water Treatment DR Capacity Related to Pump Controls



- Microgrids are being acknowledged as potential platforms to deliver ADR capacity. Research is indicating the implementation of DR programs in MGs leads to enhancing the MG reliability as well as managing the intermittent impacts of renewable energy sources as shown in Figure 88 and Figure 89, which define shed potential for microgrids employing technology solutions coupled with TOU and RTP rates, respectively.[56]

[55] Optimal Demand Response Scheduling for Water Distribution System. IEEE Transactions on Industrial Informatics, February 2018. Accessed June 2020 at https://www.researchgate.net/publication/322906865_Optimal_Demand_Response_Scheduling_for_Water_Distribution_Systems

[56] Demand Response Modeling in Microgrid Operation: a Review and Application for Incentive-Based and Time-Based Programs, June 2018 accessed July 2020 at https://www.researchgate.net/publication/326031387

Figure 91. Shaved Curve of Load After TOU Implementation on an 11-bus MG

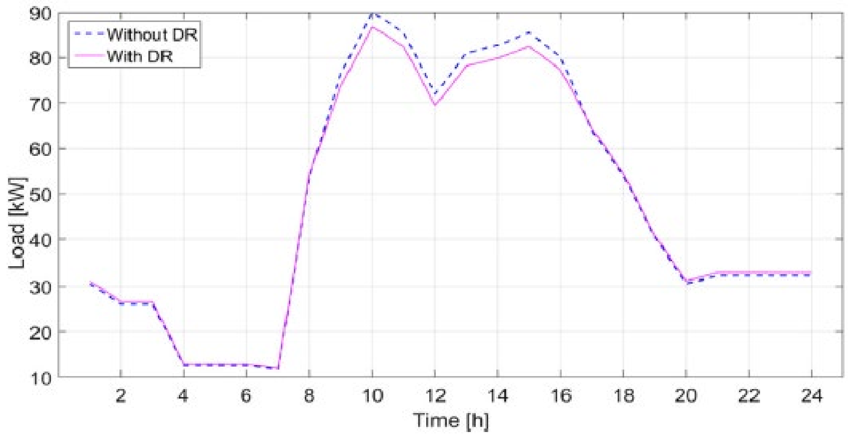
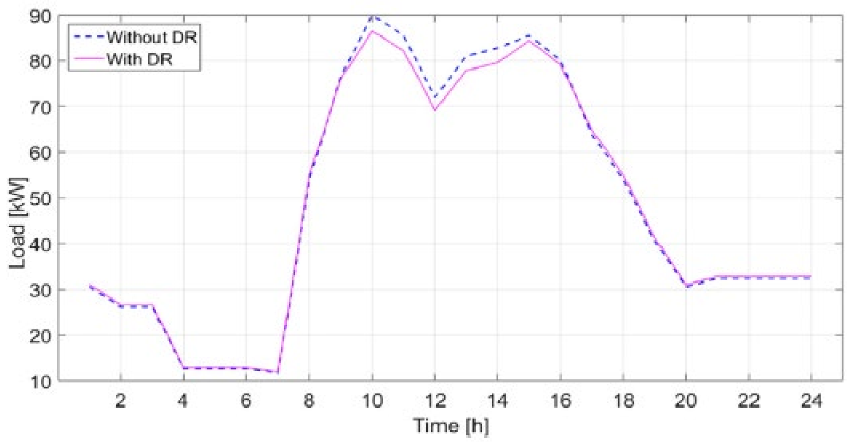


Figure 92. Shaved Curve of Load After RTP Implementation on an 11-bus MG



Key ADR Barriers

The following summarize some of the key barriers regarding an ADR solution.

1. Cost-effectiveness. The cost effectiveness of minimum curtailment threshold, such as the DRA and PS minimum curtailable capacities of 50kW and 100kW, need to assess to be reviews. Additionally, the ability to recover costs on summer resources is being restricted beginning in 2021 and this may cause an ADR program to not be cost-effective
2. Requiring 3rd party aggregators. Third party aggregators will be required to implement an ADR solution and we are uncertain if various regulatory constraints, such as the inability beginning in 2021 to claim benefits for summer DSM, will allow for a cost-effective implementation.
3. Cost to aggregate meters. Historically, it has not been cost-effective to aggregate meters however this should be reviewed in the context of increased AMI deployment, decreasing cost of control technology, and 3rd party ADR service provider ability to reduce installation and administrative costs, reporting and EM&V.
4. Cost recovery rules on pilot programs. Current regulations require that the cost of failed pilot programs must be paid back, a clear disincentive for innovation.
5. High opt-out rates on larger customers. ADR would need to be funded through the EE rider and may require participation in both the EE and DSM components to achieve appropriate funding levels. ADR

would target large C&I customers and the majority of these opt-out of the EE rider, as discussed at Table 18.

ADR Modelling Inputs

Based on the proceeding discussion, our modelling inputs and expected 10-year savings trends for the ADR are based on the following assumptions:

- First year participation of large customers of 0.50% (155 total)
- Annual growth rate of 0.50%
- 80% HVAC coincidence at the hour ending at 7:00
- 90% HVAC coincidence at the hour ending at 8:00
- 100% HVAC coincidence at the hour ending at 9:00
- No preheat period and a 2-hour recovery for HVAC yielding a revenue neutral impact
- 45 kW average per site winter impact for ventilation and lighting

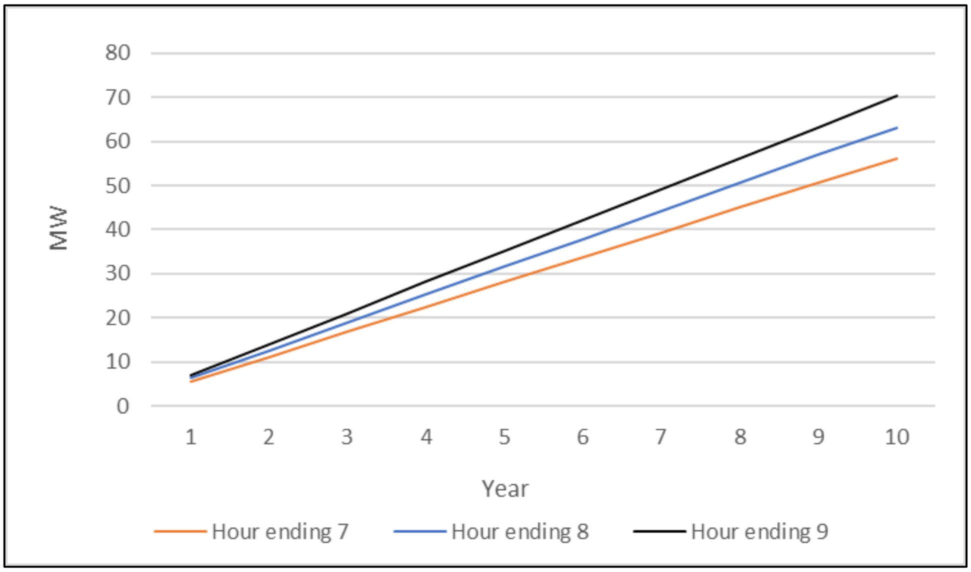
During the 3-hour event beginning at hour starting 7:00, some systems automatically adjust HVAC and light setpoints, savings will increase as facilities become more active with peak impact in hour starting 9:00. Table 54 shows our modelled ADR kW reduction occurring between 7 and 9, and likely kW increase during a 3-hour recovery period at hour starting 10. We expect ADR to be kWh neutral.

Table 54. Hourly Commercial BYOT and RET kW Impacts per Participant

Hour Starting	Coincidence	DEC	DEP
7	80%	36.28	36.28
8	90%	40.82	40.82
9	100%	45.35	45.35
10	-100%	-45.35	-45.35
11	-100%	-45.35	-45.35
12	-70%	-31.75	-31.75

Figure 90 shows the forecast by hour over a 10-year horizon, achieving a maximum impact of 70 MW in the hour ending at 9:00. Our forecast is based on 1,548 ADR participants in year 10, which represents less than 3% of our estimate of the 57,278 commercial facilities over 30,000 sq. ft, as discussed at Table 53. We did not consider industrial customer participation because of a lack of segmentation data but consider this a variable market sector.

Figure 93. 10-Year ADR Savings Forecast



Additional Large C&I Solution Set Consideration

Managed EV Charging

We reviewed commercial charging load forecasts and resulting load shapes and considered it as a long-term DSM opportunity but was omitted from our analysis based on several considerations. Figure 91 compares C&I and commercial EV charging winter peak demand profiles showing that commercial EV charging peak is at hours ending 9:00 and 10:00 and is coincident with C&I peak occurring between hours ending 9:00 and 11:00, as discussed at Table 4. In 2030, the forecasted commercial EV charging peak is 39 MW at the hour ending at 10:00, or about 0.5% of the 2018 C&I of the average winter peak of 6,142 MW at that time.

This forecast is for light vehicles (cars and pickup) charging at publicly available charging stations at commercial locations. It does not include medium and large commercial trucks (buses, delivery vans, long haul trucks etc.) and does not forecast peak hour contributions from these vehicles.

Our C&I solution set recommendation is to begin defining how managed charging will operate during winter peak system peak coincidence. Beginning this process now will accomplish three objectives:

- Profile the market to help refine estimates of system interaction. This would include tracking development of load impacts from medium and large commercial trucks
- Identify technology solutions for which pilot projects can be developed to test different approaches to managing EV charging.
- Define economic benefits that help drive commercial adoption, thereby accelerating revenue growth

Figure 92 provides our analysis of EV load forecast data provided by Duke, showing approximately 100 MW of demand at hour 9 by 2030.

Figure 94. Comparison of C&I and Commercial EV Charging Winter Peak Demand Profiles

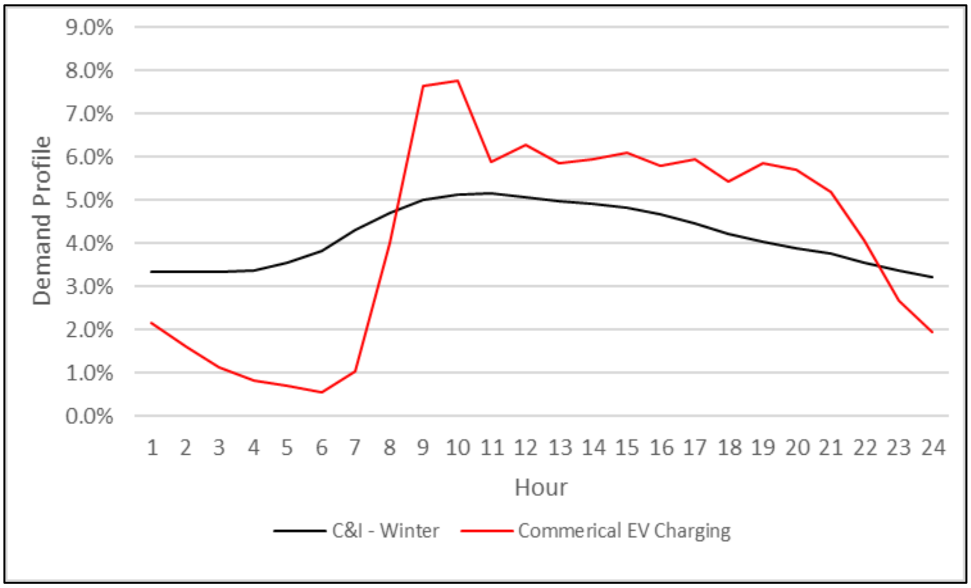
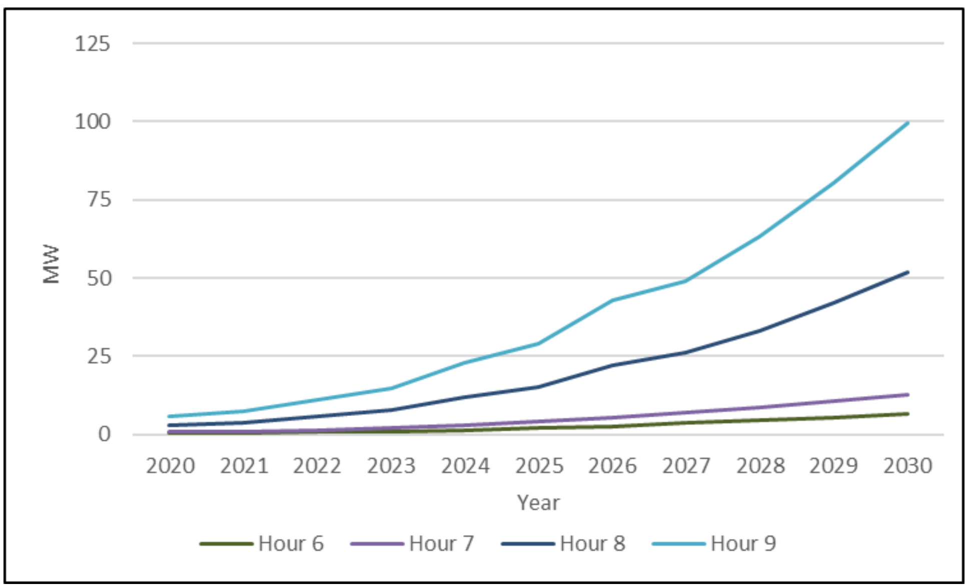


Figure 95. Public EV Charging Load Forecast by Morning Hour



Microgrids

Microgrids offer a potential solution for grid resiliency and reliability initiatives, including management of both winter and summer peak events. For example, Appendix 1, Public Segment DSM Value, provides a discussion on the value of DSM applications in the public sector, including an example of the value microgrid applications in areas where city, county, state, and federal buildings are clustered.

7. Appendices

Appendix 1, Public Segment DSM Value

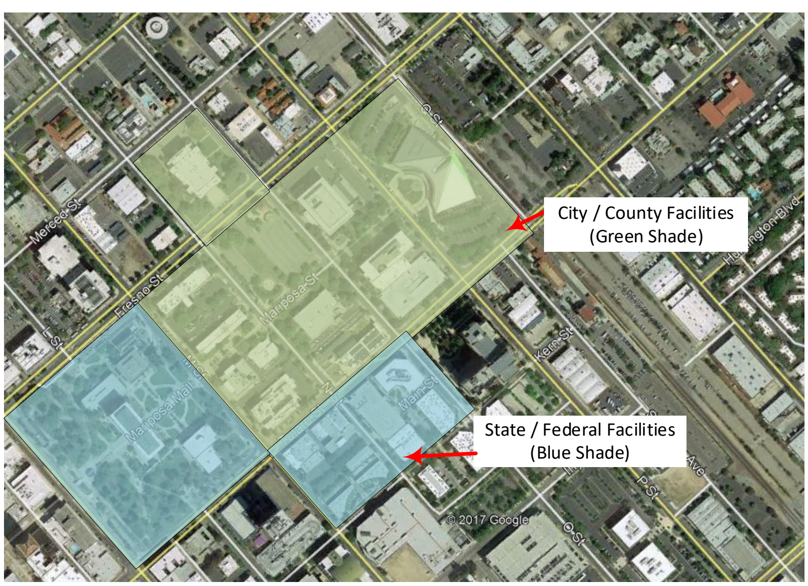
Consider that the public sector has various characteristics that support active load management and has provided market signals that align with an ADR solution:

- The public sector is larges and includes a significant number of facilities operated by several hundred entities across NC and SC, including:
  - Federal
  - State
  - County
  - City
  - Districts (e.g., school and water districts, etc.)
- Most customers at the state, county, and city level are in financial distress and reducing energy costs is a viable and ongoing focus. These entities likely have significant deferred maintenance backlogs where program interventions could help manage fuel and demand charges while supporting facility renewal projects, defined and funded each year through their annual budgets.
- This segment is easy to identify and categorize by NAICS since some facilities (e.g., school, jail, courthouse) rarely change use and once categorized the segment stays the same.
- A core focus of every city or county is to plan development (both new and economic redevelopment) and ensure code compliance. These functions provide excellent platforms to reach broader residential and commercial customers, especially large developers through partnerships that can drive addition participation in Dukes suite of EE and DSM offering.
- In addition to tradition planning activities, a growing number have, or are developing, sustainability initiatives such as the following that would make them amenable to EE/DSM participation:
  - SustainableNC is a partnership initiative to encourage public and private collaboration as NC strives to become a national leader in energy innovation and low carbon economy.
  - Three Zeros Environmental Initiative is UNC-Chapel Hill's principal sustainability program supported through the UNC Office of Sustainability and represents an integrated approach to reducing its environmental footprint through three sustainability goals: net zero water, zero waste to landfills and net zero greenhouse gases.
  - The Raleigh Office of Sustainability works to create an organizational environment where each City departmental operation, investment, and initiative incorporates the Council's commitment to building a sustainable city.
  - City of Durham Sustainability Report communicates the City of Durham's sustainability story to date and informs a strategic path forward with a timeline of major environmental milestones, key indicators, and accomplishments across City departments.
- Public entities have predictable and consistent load profiles that align well with 6:00 a.m. to 9:00 a.m. winter curtailment (and also summer peak events that occur late in the day).
- They are stable customers that are generally safe from economic disruption or changes in their portfolio of facilities.
- There are 100's of public entities in NC and SC that all manage reasonably sized portfolios of buildings and they likely have a single, or a few, point(s) of contact in charge of energy. This can be leveraged to implement efficient outreach and marketing efforts during development. This can also be

leveraged to efficiently manage communication during events, especially long duration events spanning multiple consecutive days.

- Unlike many commercial customers where ownership and decision can be remote, State, County, and City entities reside in Duke's NC and SC territories and have a vested interest in success.
- In general, they have less risk from curtailment than other segments, such as liability concerns related to health care or spoilage issues related to the grocery or warehouse markets.
- Public sector entities control fleets of vehicles, ranging from pools of cars and light trucks to school and transit buses that will electrify over the coming years. Establishing a foundation of load management early in this transition will likely result in a more effective grid response and potentially accelerate revenue growth related to EV adoption. Duke may also leverage relationships with public entities to expand innovations with EV charging designs with EV manufacturers, such as the Proterra, Asheville Redefines Transit (ART) project or the transit systems in North Carolina's Research Triangle grant project.
- Many Public sector facilities often lack sophisticated energy information (EIS) and energy management control systems (EMCS). Targeting this sector presents an opportunity to implement technologies that compliment Duke's AMI and data analytics rollout in a market that is likely using less energy management technology than other commercial segments. EIS and EMCS technologies are the technologies that enable effective load management and provide the additional benefit of supporting more aggressive fuel reduction (e.g., Energy Efficiency).
- Many public sector facilities are clustered in close proximity within major population centers and likely constitute a viable market for advanced technology solutions such as microgrids, either islanded or virtual designs that tie buildings together in a network with a single reporting/control interface. This characteristic makes interconnection across multiple facilities manageable, especially as AMI deployment advances. This characteristic also presents opportunities for district level thermal storage and networked chemical storage. For example, Figure 93 shows a microgrid concept Tierra developed for the City of Fresno, CA, that includes 23 separately metered facilities within a 66-acre area that represented 1.8 MW of total peak load. This design included both hard interconnects and network interconnects where distributed batteries were proposed for peak management through a common reporting and control hub.

Figure 96. Fresno Public Facility Microgrid Footprint



Appendix 2, Water Treatment Segment DSM Value

As discussed at Table 16, both PS and DRA have lost capacity in the water treatment segment from changes in EPA rules that preclude the use of backup generators for DSM purposes. We believe that backup generators are the only source of DSM that Duke pursued in that market segments, however other opportunities exist for the application ADR that are attractive because of the size and diversity of available loads at most plants, and the number of water plants in operation in NC and SC.

The following discussion provides excerpts from a report[57] coordinated by the Demand Response Research Center and funded by the Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy and Office of Electricity Delivery and Energy Reliability, under Contract with the California Energy Commission (CEC), Public Interest Energy Research (PIER) Program. During our work we identified 210 water treatment facilities serving 9,609,446 persons, or approximately 61% of the combined NC and SC population of 15,636,798, many of which are being served by Duke.

Overview

This report summarizes Lawrence Berkeley National Laboratory's Demand Response Research Center (DRRC) work involving California wastewater treatment facilities from 2008 through 2014. Through sector specific research, the DRRC's Industrial Demand Response team assessed the potential opportunities and barriers to implementing automated demand response (ADR) capabilities in these facilities.

DR refers to a set of strategies and systems used by electricity consumers to temporarily modify their electrical load in reaction to electrical grid or market conditions. Three case studies carried out as part of this work suggest that wastewater treatment plants are prime candidates for ADR due to their large energy consumption during utility peak periods, process storage capacity, high incidence of onsite generation equipment, and control capabilities.

Equipment Controls

The following describes specific control opportunities for four types of equipment in the wastewater treatment process:

Aerators:

Implementing automatic dissolved oxygen control for an aeration system can reduce facility energy use by as much as 25%. The control system can automatically adjust blower output at preset time intervals based on a comparison between an average of dissolved oxygen readings in the aeration basins and a recommended dissolved oxygen concentration.

Disinfection Equipment:

Irradiating the waste stream with ultraviolet (UV) light is becoming a common method of disinfection, because unlike traditional processes such as chlorination and ozonation, using UV light does not involve the addition of chemicals. However, UV disinfection uses more electrical power than chemical-based methods. Implementing UV light control strategies can help minimize the impact of this disinfection method on energy costs. For example, control data from the SCADA system can enable facilities to respond to changes in the waste stream, such as increased levels of total suspended solids, turbidity, and biological oxygen demand. Using new on-line sensing technologies can also reduce UV light related power costs. For example, turbidity sensors and UV absorbance sensors can be used in a SCADA system to

[57] Opportunities for Automated Demand Response in California Wastewater Treatment Facilities Arian Aghajanzadeh, Craig Wray and Aimee McKane Environmental Technologies Area August 2015

automatically control power applied to UV lights and to optimize disinfection while eliminating unnecessary power consumption, as well as extending the life of expensive UV lamps.

Load Shed Strategies

There are several opportunities to consider for load shedding in a wastewater treatment facility during demand response events. These include turning non-essential equipment off and transitioning essential equipment to onsite power generators. In addition, facilities can use VFDs to operate motor----driven process equipment (i.e., aerator blowers and pumps) at lower speeds, which reduces demand and better enables process operations to maintain effluent quality within regulatory limits. Lighting systems, as well as heating, ventilating, and air conditioning (HVAC) systems also can be retrofitted to save energy and reduce overall energy demand and operating expenses. Some of the opportunities are more appropriate than others, depending on the equipment type. Further information about specific equipment follows.

Aerator Blowers: In many cases, treatment facilities with diffused aeration systems use 50 to 90% of total electric power demand to run aerator blower motors (Thompson, et al. 2008). Using VFDs to control blower speed and reduce this large demand when possible should be considered. Simply shutting down blowers during demand response events also could be an effective way to significantly reduce the plant's energy demand.

Pumps:

Pumps are used in the majority of wastewater treatment processes, including influent pumps, grit pumps, and lift pumps. Given that the energy required for influent wastewater pumping alone can range from 15 to 70% of the total electrical energy, there is a significant opportunity to shed loads associated with pumping. (Thompson, et al. 2008) Pumps are often oversized for the average wastewater flow and thus operate inefficiently. Wastewater treatment facilities can frequently address inefficiencies due to pump oversizing by using VFDs or applying operational strategies that involve staging multiple pumps, which allows for more efficient utilization of pumping capacity.

Load Shift Strategies

Implementing load shift strategies in wastewater treatment facilities allows the main energy-intensive treatment process to be rescheduled to off-peak hours. Electrical load management is a frequently used method for reducing energy use in these facilities and can result in 10 to 15% energy savings. The following discusses over-oxygenation, untreated wastewater storage, process rescheduling, and anaerobic digestion opportunities to shift load.

Over-Oxygenation:

Dissolved oxygen (DO) is necessary for microorganisms to breakdown organic material present in water. A major opportunity for shifting wastewater treatment loads from peak demand hours to off-peak hours is over-oxygenating stored wastewater prior to demand response event. Doing so allows aerators to be turned off during the peak period.

Storing Wastewater:

If site conditions allow, wastewater treatment facilities can utilize excess storage capacity to store untreated or partially treated wastewater during demand response events and then process it later during off-peak hours. However, building storage basins can be expensive, so equalization basins can be used instead. Equalization basin drains open and close as needed to maintain a constant level in the influent wet well, which creates a near constant flow through the treatment process. Unused tanks can be converted into equalization basins during facility upgrades and expansions. Treated wastewater can be stored as well. In one of the case studies, pumping treated effluent to the ocean was simply shifted to off-peak hours

Process Rescheduling:

Facility processes such as backwash pumps, biosolids thickening, dewatering and anaerobic digestion can be rescheduled for operation during off-peak periods, providing peak demand reductions in wastewater treatment facilities.

Anaerobic Digestion:

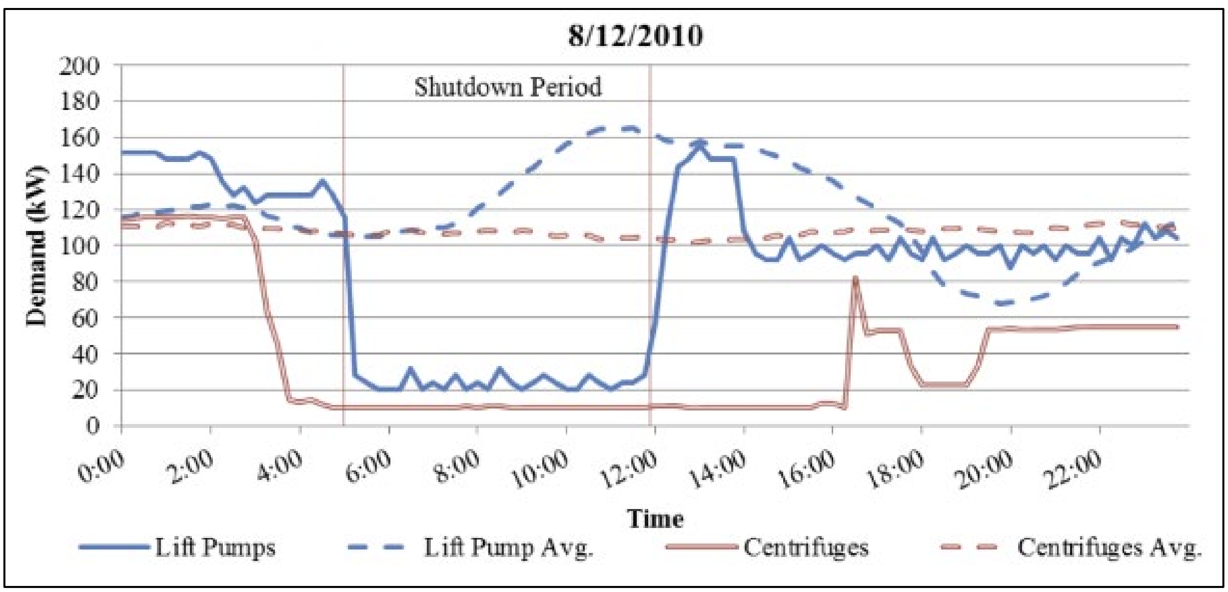
Using the biogas from anaerobic digestion to produce electricity can be an important demand response resource for the wastewater facilities.

Case Study

The average baseline demand at the Southeast facility was approximately 4 MW. During the rainy season (October----March), the facility treated 40% more wastewater than during the dry season but demand only increased by 4%. More specifically, analyses of the collected data found a strong correlation between daily influent flow and total lift pump demand (R2=0.55) but no correlation between influent flow and centrifuge demand. The data also indicated that the demand from the lift pumps and centrifuges during normal utility peak hours (12 p.m. to 6 p.m.) was not substantially different than the demand during the rest of the day.

Based on the sub metered data, on average, 154 kW and 86 kW of load shift are available from the lift pumps and centrifuges, respectively, for a total shift of 240 kW (approximately 6% of average plant demand). Similar shifts were observed during partial-day plant shutdowns. A reduction in demand from lift pumps and centrifuges during one such shutdown is shown in Figure 94.

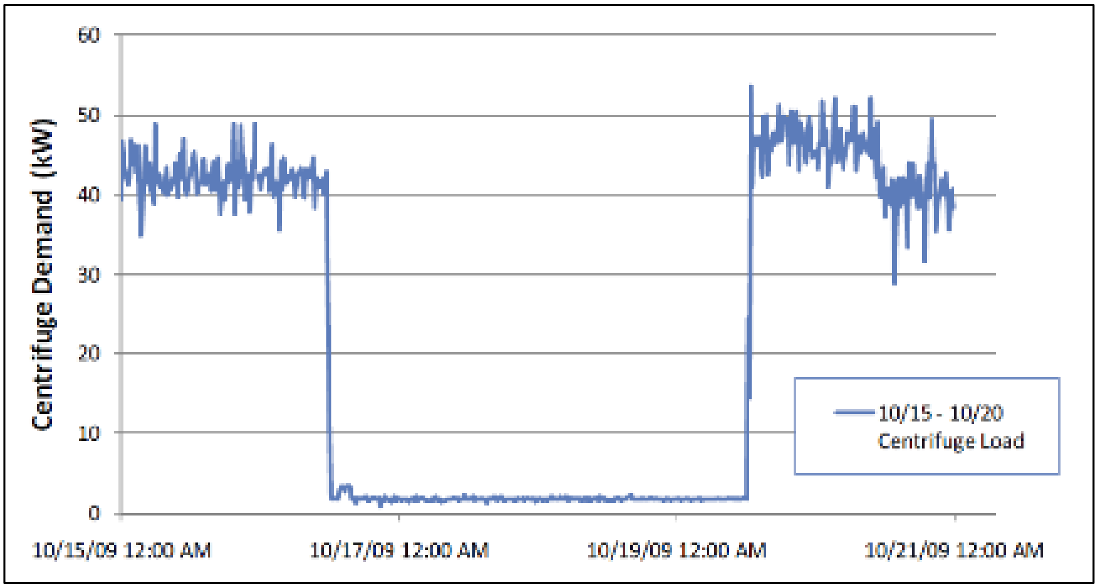
Figure 97. Shift Profile, Wastewater Treatment Plant Case Study #1



In this case study, the plant's influent flow followed a diurnal pattern of a morning and evening peaks, with a sharp dip at night. There was a small positive correlation between outdoor air temperature and influent flow. Further, this study observed that this facility maintains a stable level of dissolved oxygen even as influent varies. This was accomplished through the use of a modulating value that adjusts the amount of air reaching the basin. There was a slight correlation between the outdoor air temperature and dissolved oxygen levels at this facility.

Demand response tests on the effluent pumps resulted in a 300 kW load reduction. Tests on the centrifuges resulted in a 40 kW load reduction, as shown in Figure 95. These reductions from the centrifuges and effluent pumps were enabled by the large potential for onsite storage of sludge and effluent, respectively. Although tests on the facility's blowers resulted in peak period load reductions of 78 kW, as discussed in Chapter 4 of the study, sharp, short-lived increases in effluent turbidity occurred within 24 hours of the test.

Figure 98. Shift Profile, Wastewater Treatment Plant Case Study #2



Appendix 3, DSM Program Structures and Types

Table 55. DSM Program Structures

OPCO	Curtailable Program	Contract Term	Contract Commitment	One-Time Participation Incentive	Monthly Capacity Credit	Event Reduction Credit	Event Non-Compliance Definition/Penalty	Minimum Annual Events
DEP	DRA	Initial 5-year automatic 2-year renewals	Fixed Reduction	$50/kW	$3.25/kW	$6.00/kW	<90% of Contract/ Loss of 4 monthly credits	3 summer
	LLC	Initial 5-year automatic 2-year renewals	Firm Demand	-	NC - $5.40/kW SC - $4.60/kW + $1.02/kW adder	-	Event Demand above Firm Demand/ NC - $50/kW; SC - $45/kW	-
DEC	PS-M	Initial 3-year, automatic 1-year renewals	Firm Demand	-	$3.50/kW	$0.10/kWh	Event Demand above Firm Demand/ $2.00/kWh	-
	PS-G	Initial 3-year, automatic 1-year renewals	Fixed Reduction	-	$3.50/kW	$0.10/kWh	Event Demand above Firm Demand/ $2.00/kWh	12 monthly tests
	PS-V	Initial 1-year, automatic 1-year renewals	Firm Demand	-	-	Energy credit based upon market prices	Event load reduction less than 50% of nominated load reduction/ Loss of event credit	-
	IS	CLOSED	Firm Demand	-	$3.50/kW	-	Event Demand above Firm Demand/ $10.00/kW	-
	SG	CLOSED	Fixed Reduction	-	$2.75/kW + $10 compliance adder	Energy credit based upon market fuel costs	-	12 monthly tests

Table 56. DSM Program Types

OPCO	DSM Curtailable Programs	Legacy Rate Base Curtailable Programs	Legacy Dynamic Pricing Rate Schedules	Legacy Rate Base Non-Firm Rates & Riders
DEP	Demand Response Automation (*Rider DRA*)	Large Load Curtailable (*Rider LLC*)	Large General Service Real Time Pricing (*LGS-RTP*)	Incremental Power Service (*Rider IPS*)
		Large General Service - Curtailable Time-of-Use (*LGS-CUR-TOU*)*		Dispatched Power (*Rider 68*)
				Supplementary and Non-Firm Standby Service (*Rider NFS*)
				Supplementary and Interruptible Standby Service (*Rider 57*)
DEC	PowerShare Mandatory Option (*Rider PS*)	Interruptible Power Service (*Rider IS*)**	Hourly Pricing for Incremental Load (*HP*)	*n/a*
	PowerShare Generator Option (*Rider PS*)	Standby Generator Control (*Rider SG*)**		
	PowerShare Voluntary Option (*Rider PS*)			

Attachment 3
E-100, Sub 165

DUKE ENERGY

DUKE ENERGY

Winter Peak Demand Reduction Potential Assessment

December 2020

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1 WINTER PEAK DSM POTENTIAL MODELING OVERVIEW

Duke Energy North Carolina and South Carolina engaged Dunsky Energy Consulting, as part of the Tierra Inc team to model the winter peak demand reduction potential in the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) systems.

The objectives of this modelling exercise were to

1) Capture the potential for new programs and measures to reduce the winter peak demand in each of DEP and DEC, via Demand Side Management (DSM) programs target to residential and commercial customers
2) Quantify the degree to which this potential is incremental to the current Duke DSM program impacts, and compare the findings to the Market Potential Study, recently conducted by Nexant[1].
3) Provide insights that can help Duke prioritize winter peak DSM approaches in the short term, as well as identify the potential for longer term strategies.

Following on Tierra's work to identify and characterize new rate structures and mechanical solutions, the winter peak DSM potential assessed the ability of behavioral measures, equipment controls and industrial and commercial curtailment to reduce Duke's overall system peak in each system.

The report includes an introduction to the modelling methodology, followed by a step-by step description of the model findings. The overall potential assessment is then provided in section 3 of this report, followed by a concluding section containing key take-aways. Finally, a set of detailed results and input assumptions is appended.

1.1 DSM POTENTIAL ASSESSMENT APPROACH

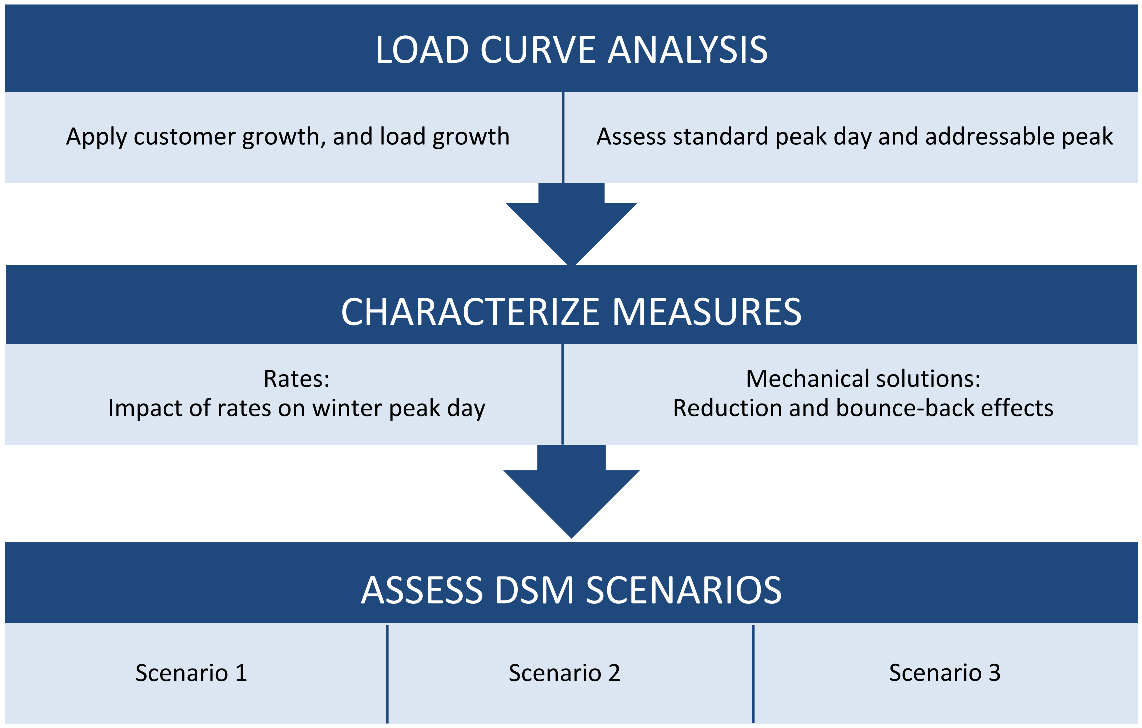
The DSM potential is assessed against Duke's hourly system load curves and winter peak demands. Figure 1 below presents an overview of the steps applied to assess the DSM potential in this study.

Key to this assessment is the treatment and consideration Duke's DEC and DEP winter system peak-day hourly load curve. As part of this process, standard peak day 24-hour load curves are identified and adjusted to account for projected load growth over the study period. This allows the model to assess each measure's net reduction in the annual peak, considering possible shifts in the timing and duration of the annual winter peak in each system.

In some cases, this may lead to results that are contrary to initial expectations, especially when DSM programs such as dynamic rates or equipment direct load control (DLC) measures are looked at only from the perspective of how they may impact individual customer peak loads at the originally identified peak hour.

[1] Nexant, *Duke Energy North Carolina EE and DSM Market Potential Study,* and *Duke Energy South Carolina EE and DSM Market Potential Study*, May 2020

Figure 1 - DSM Potential Assessment Approach



The achievable potential is assessed under three scenarios corresponding to varied DSM approaches or strategies (Figure 2). These scenarios were developed with the goal of assessing the impacts of different rate structures and a selected set of mechanical solutions on the load curve of both DEC and DEP. More details on the scenarios can found in the section 3.3 of this report.

Figure 2. Demand Response Program Scenario Descriptions

LOW	Applies a limited number of rate structures with conservative adoption or incentive levels in conjunction with a defined set of mechanical solutions.
MID	Introduces an additional rate structure into the residential market and increases C&I adoption or incentive levels. Mechanical solutions are adapted to the new rate structures.
MAX	Applies a variety of residential rate structures and more aggressive C&I adoption and incentive levels to estimate maximum achievable potential. Mechanical solutions are adapted to the new rate structures.

1.2 SEGMENTATION

Market segmentation is essential to accurately estimate the DSM potential and is one of the first step of the modelling. Customer information provided was broken down by rate class for both DEC and DEP. As rates patterns and DSM savings vary by customer characteristics, DEC and DEP customers were segmented in three ways:

- **By market sector**: Residential, Commercial and Industrial

- **By rate class**: Within each sector, customers can choose a variety of rate classes, depending on their overall size (assessed by annual peak kW power draw) and rate structure preference. By segmenting customers according to their applicable rate classes, the model can assess the impact of customers moving to new or adjusted rate structures. The key rates classes in both DEP and DEC and presented in Table 1. Both "other" rates encompass all the other rates not specifically mentioned that are available in each system.

Table 1 – Rate Class Segmentation

DEC - Rates	DEP - Rates
SGS	SGS
LGS	MGS
OPTC	LGS
OPTI	RTP
RS	Res
RE	Other
Other	

- **By customer segment:** Within each market sector/rate class segment, Duke's commercial and industrial customers were further segmented by business type (i.e., offices, schools, retail etc.) using U.S. Energy Information Agency's (EIA) Commercial Buildings Energy Consumption Survey (CBECS - 2012) and Residential Energy Consumption Survey (RECS - 2015).

2 DSM POTENTIAL ASSESSMENT

2.1 STEP 1 - LOAD CURVE ANALYSIS

The peak load analysis is the first step in the DSM potential analysis, through which key constraints are defined to identify the solutions that will be deployed, and the scenarios modelled to reduce winter peak demands.

First, the winter season standard peak day load curve is defined, and the impacts of load growth projections are applied. The standard peak day load curve for the electric system is defined by taking an average of the load shape from each of the top ten winter peak days in the forecasted hourly load data provided[2] (Figure 3 for DEC and Figure 4 for DEP).

Figure 3 - DEC Standard Peak Day (incl. wholesale) Based on Historical Data – 2020

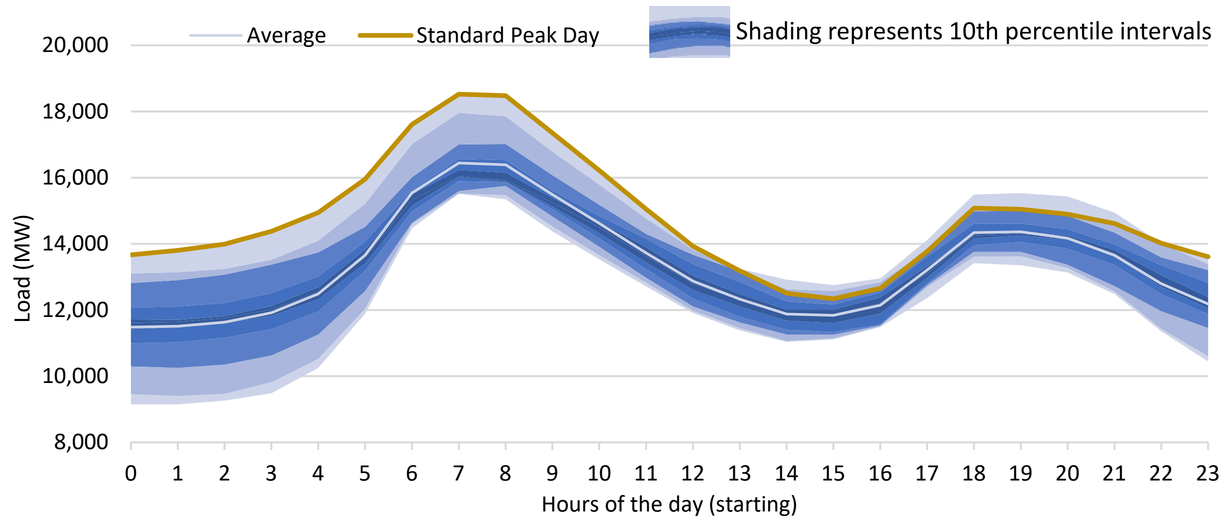
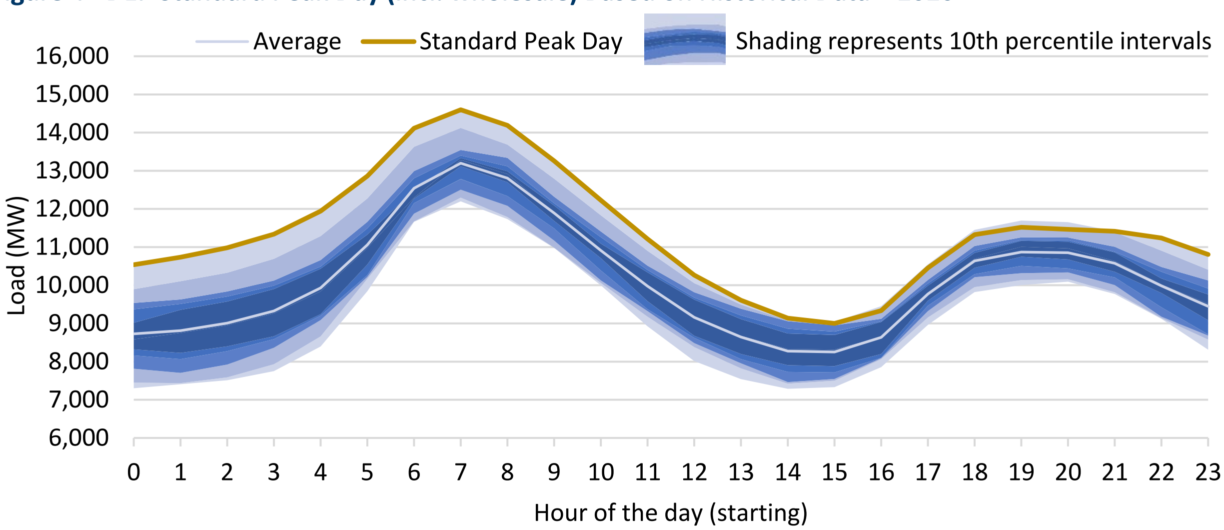


Figure 4 - DEP Standard Peak Day (incl. wholesale) Based on Historical Data – 2020



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[2] Provided forecast included years between 2020 and 2045.

This analysis shows that Duke's systems, in winter, have a steep morning peak, which is driven predominantly by residential and commercial space heating. The duration and steepness of the peak curve indicate that measures with bounce-back or pre-charge effects are not likely to pose a real problem in winter by creating new peaks when shifting load from one hour to another.

An hourly load forecast was provided, for each year from 2021 to 2041, thus the winter peak load curve assessment was repeated for each year to determine the annual winter peak in each of the year of the study period (2021-2041), resulting in the peak day characteristics listed in Table 2 below.

Table 2 – Standard Peak Day Key Metrics

Year	Peak Demand (MW) excl. wholesale	
	DEC	DEP
2021	16,533	10,551
2026	16,611	10,661
2031	17,242	11,020
2036	18,191	11,593
2041	19,315	12,332

Once defined, the standard peak day utility load curve is then used to characterize the DSM solution set measures, by defining the peak load reduction possible at each hour of the day. These are then used to assess the measure-specific peak demand reduction potentials at the technical and economic potential levels.

2.2 STEP 2 - SOLUTION SET CHARACTERIZATION

Based on the load analysis and detailed review of Duke's current program and rates[3], a solution set was developed to reduce the winter peak demand in both DEP and DEC. The mechanical solutions and rate structures considered are described below.

2.2.1 MECHANICAL SOLUTIONS

As outlined in Tierra's Winter Peak Analysis and Solution Set report, a solution set was identified to specifically address the DEC and DEP winter peak. Once selected, measures were characterized individually. Measure characterization is the process of determining the hourly load curve impacts (kW reductions in each hour), as well as the measure costs, applicable markets and EULs. The measure characterizations leverage a range of secondary sources, including energy modelling profiles and empirical data from relevant jurisdictions to determine the resulting load curve impacts.

Based on the Winter Peak Analysis and Solution Set report analysis, a total of eight technologies/programs were chosen to be integrated into the modelling.

[3] More details are provided in Tierra's Winter Peak Analysis and Solution Set report.

- **Residential**
    - Bring Your Own Thermostat (BYOT)
    - Rate Enabled Thermostats (RET)
    - Rate Enabled Residential Hot Water Heating Controls (RE-HWH)
    - Winter Heat Pump Tune-up
    - Battery Energy Storage[4]
- **Small and Medium C&I**
    - Bring Your Own Thermostat (BYOT)
    - Rate Enabled Thermostats (RET)
    - Winter Heat Pump Tune-up
- **Large C&I**
    - Automated Demand Response (ADR) for larger C&I flat rate customers selecting advanced rates

More details on the key measure inputs are provided in the Winter Peak Analysis and Solution Set report.

2.2.2 RESIDENTIAL RATES

Close attention was paid to the rates structure as they not within the scope covered by Nexant's 2020 MPS study, and thus they provided an opportunity to determine if and where further potential for winter peak reductions may lie. Rates are used to encourage customers to modify their behavior and change consumption patterns. Four specific rates structures were designed for the study, applying the three common residential dynamic rate structures: Time-Of-Use Rate (TOU), Critical Peak Pricing (CPP) and Peak Time Rebate (PTR). Based on the load curve analysis, the peak hour charges were applied from 5:00 am to 9:59 am on weekdays only.

- **TOU Rate**
- **TOU Rate with CPP**
- **Bill Certainty with PTR**
- **Flat Volumetric with CPP**

Further details on the Residential DSM rates are provided in the appendix.
[5]

2.2.3 COMMERCIAL & INDUSTRIAL RATES

Commercial rates were derived for customer segments small, medium, and large annual consumption profiles. Both CN&I rates apply PTR rates to attract customers by providing a benefit for demonstrated

[4] The forecast of residential Battery Energy Storage represents a conservative view based on uncertainties about market adoption for this technology and is discussed in more detail in the Winter Peak Plan report completed as part of this same research effort.

[5] The reports produced by the Winter Peak Study, including the Winter Peak Demand Reduction Potential Assessment report, use the term Commercial and Industrial to discuss rates used by the non-residential market sectors and is intended to help define the significant difference in load shapes between commercial and industrial customers and also define DSM opportunities targeting each market segment, Commercial and Industrial rates and customers may be referred to as "Non-residential" or "General Service" rates in other Duke publication and communications.

peak event demand reductions. By using a rebate approach, PTR rates is particularly attractive to large customers who see in it as a win-win situation. Considering the variety of C&I rates as well as the option for large customers to opt-out from DSM programs, this rate is potentially an opportunity to attract more customers than current DSM programs. The rate consists of offering a rebate for reducing their load below a customer-specific baseline during peak times

- **Small C&I Customers – Bill Certainty with PTR**
- **Medium and Large - C&I Customers - PTR**

For modelling assumptions, to avoid any double-counting, participants already enrolled under current DSM programs (DRA or PowerShare) are excluded from the customers count. Further details on the C&I DSM rates are provided in the appendix.

2.3 STEP 3 - SCENARIOS

As a final analysis step, three defined adoption scenarios are applied, and the winter peak impacts are assessed. Three scenarios were developed to be viable in both DEC and DEP systems, with key program inputs defined for each. This section summarizes the selected scenarios and main program inputs.

2.3.1 LOW SCENARIO

The low scenario includes a solution set that includes the most straight-forward combination of rate options. A new residential TOU rate structure would be offered along with a TOU+CPP option. On the C&I side, a PTR rate would be deployed with a conservative adoption rate for SGS customers and a low PTR incentive for medium and large C&I.

Table 3 – Overview of the Low Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates	• Small C&I - Bill Certainty + PTR Low adoption (10%) • Medium and Large C&I - PTR Low incentive (30$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I- BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.2 MID SCENARIO

The Mid scenario aims to expand on the Low scenario by including a new residential Bill Certainty rate option and increase adoption and PTR incentives in the C&I sector.

Table 4 – Overview of the Mid Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates	• Small C&I - Bill Certainty + PTR Mid adoption (15%)

	• Bill Certainty + PTR Rates	• Medium and Large C&I - PTR Mid incentive (60$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I - BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.3 MAX SCENARIO

The Max scenario aims to maximize demand response potential by adding a new CPP option, maximizing adoption in small C&I, and increasing medium and large C&I PTR incentives to approach the limits that still render the programs cost effective (i.e., the incentive levels that yield UCT results of 1.2 or higher).

Table 5 – Overview of the Max Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates • Bill Certainty + PTR Rates • Flat Volumetric + CPP Rates	• Small C&I - Bill Certainty + PTR High adoption (20%) • Medium and Large C&I - PTR High incentive (90$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I - BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.4 KEY VARIABLES FOR DSM POTENTIAL ASSESMENT

The variables below are key to the DSM assessment as they feed the achievable potential and costs calculation. These assumptions were developed based on Duke's inputs, jurisdictional scans and professional judgment.

RESIDENTIAL PARTICIPATION RATES

Table 6 below summarizes adoption levels for each DSM rate per under each scenario treatment.

Table 6 – Adoption for Residential Rates*

	Low Scenario			Mid Scenario			Max Scenario		
Target Rate	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**
TOU	2%	10%	5%	2%	10%	5%	4%	20%	11%
TOU + CPP	10%	15%	12%	10%	15%	12%	6%	9%	7%
Bill Certainty + PTR	-	-	-	8%	20%	13%	10%	25%	16%
Flat Volumetric + CPP	-	-	-	-	-	-	4%	11%	7%
Total residential Market	***12%***	***25%***	***18%***	***21%***	***45%***	***31%***	***25%***	***65%***	***42%***

*Due to rounding, numbers may not add up

Adoption levels were first determined for the DEC all-electric residential rate class (RE). It is expected that this rate class would benefit the most from the selected rates structures (higher electric bills and peak demand) and therefore, the rate with the highest adoption levels. Adoption levels for all-electric residential rate are derived from Brattle's Time-Varying Price Enrollment Rates Study[6], a study that bundles results from six market research studies and fourteen full-scale deployments. Based on this study findings, for an opt-in residential dynamic rate, TOU rates can reach on average 28% of the customers, CPP rates can achieve an average of 17% and PTR rates average 21%.

For the Low scenario, it is therefore assumed that a total of 25% of RE customers would enroll in a TOU rate structure after full deployment of the rates. Of those customers willing to join a TOU rate, it is estimated that 15% would prefer a TOU+CPP version of the rate. For the Mid scenario, the adoption for PTR was assumed to be 20% of RE customers. It is important to note that to keep conservative estimates, the averages for all residential customers from the Brattle study were applied as our highest adoption estimates for the RE rate class only.

Finally, for the Max scenario, the objective was to reach a maximum of customers through large-scale deployment and intensive marketing. It is estimated that a total of 28.5% of customers will be interested in a TOU rates structure, corresponding to the average from the Brattle's Time-Varying Price Enrollment Rates Study. Based on findings from Sacramento Municipal Utility District's Consumer Behavior Study[7], it is assumed that the participation rates between TOU+CPP and a CPP rate would be similar with a slightly preference for a CPP rate structure[8]. This was further corroborated through the preliminary survey results from Duke's Flex Savings Options Pilot. As for PTR, adoption levels as high as 56% were achieved in other jurisdictions. Taking into consideration the multiple rates offered conjointly in this scenario, a maximum adoption of 25% has been selected.

Once RE rate class adoption levels were established, those levels were used to determine the potential adoption for DEC standard residential rate (RS) which mainly includes non-electric heated customers. The adoption levels were assumed to be proportional to the average bill savings. The lower the bill savings, the lower the adoption. Load impact results from the Flex Savings Options Pilot were used to assess the level of achievable savings.

Finally, adoption rates for customers under the DEP residential rates were prorated based on the number of customers all electric versus non-electric heated.

C&I PARTICIPATION RATES

Table 7 below present the incentives and adoption level used for the C&I DSM rate scenarios.

Table 7 – Adoption for C&I Rates

C&I	Low Scenario	Mid Scenario	Max Scenario

[6]Adoption for opt-in dynamic rates from R. Hledik, A. Faruqui and L. Bressan, *Demand Response Market Research: Portland General Electric, 2016 to 2035 – Appendix A: Participation Assumptions*, 2016.

[7] SMUD, *SmartPricing Options Final Evaluation*, 2014. Retrieved at: https://www.smud.org/-/media/Documents/Corporate/About-Us/Energy-Research-and-Development/research-SmartPricing-options-final-evaluation.ashx

[8] The TOU+CPP rate structure had a higher percentage of drop-out customers than the CPP rate structure (7.7% vs 5.7% - Figure 1.2). Our estimates use drop-out percentages rather than acceptance rates because acceptance rates reflect decisions made at the beginning of the pilot, before experiencing the rate.

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

Small C&I Customers

Adoption levels were also based on Brattle's Time-Varying Price Enrollment Rates, with again a reduction factor to account for the low elasticity of the small C&I sector. Since there is uncertainty in this approach, three scenarios, with various adoption levels were modelled to see the impact of adoption on demand response potential.

Medium & Large C&I Customers

For the medium and large C&I rates, the model determines the expected maximum program participation based on the incentive offered, the level of marketing, and the total number of eligible customers, by applying DR program propensity curves developed by the Lawrence Berkeley National Laboratory[9]. The propensity curve was calibrated to the existing participation level from DRA and PowerShare.

OTHER PROGRAM OUTPUTS

The modelling includes several program inputs. Below are presented a few of these key variables. More detailed are included in Appendix A.2.

Participation and Enrollment Ramp up: Participation and enrollment ramp ups are applied to every modelled solution. The BYOT program is assumed to be deployed in 2021 while all other programs are not assumed to start before 2022 at least. The low scenario assumed a 5-year ramp up for each rate solution while the Mid and Max scenarios assume an 8-year ramp up.

Program Costs: For every DSM program, a one-time fixed cost is applied for program development. For recurring costs, an annual fixed cost is assumed along with a variable cost per customers. Program costs also include sign-up and/or annual incentives.

Program Lifetime: For mechanical solutions, programs are assumed to last for the whole measure life.

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

3 DSM ACHIEVABLE POTENTIAL RESULTS

The overall achievable winter DSM potential in each year for each scenario is presented below, and in all cases the values are presented are incremental to current DSM program winter peak impacts. These results represent the overall winter peak load reduction potential when all constituent programs are assessed together against the DEP and DEC load curves, accounting for combined interactions among programs and reasonable roll-out schedules.

Measures that cost-effectively deliver sufficient peak load reductions individually are retained and applied in the achievable potential scenario analysis. Consistent with the other savings modules in this study, only cases where the measure yields a Utility Cost Test (UCT) value greater than 1.1 are retained in the economic and achievable potential.

Under the Low scenario, which represents the most conservative scenario, the winter potential is estimated to reach **1,079 MW in 2041** (651 MW in DEC and 428 MW in DEP), which represents 3.4% and 3.5% of DEC and DEP peak, respectively. Under the Mid and Max scenarios, the achievable potential estimates respectively achieve **1,273 MW** (766 MW in DEC and 507 MW in DEP) and **1,378 MW** (834 MW in DEC and 544 MW in DEP) **in 2041**, translating into 4.0% (DEC) and 4.1% (DEP) for the Mid scenario and 4.3% (DEC) and 4.4% (DEP) for the Max scenario of the systems peaks. Based on these results, the scenario analysis indicates that DSM rate structures that have been piloted by Duke (TOU and TOU+CPP) can capture a little over 45% of the expected potential from DSM rates, while the rest of the potential lies in new rates offers (PTR and CPP).

Figure 5 – DEC potential, by scenario

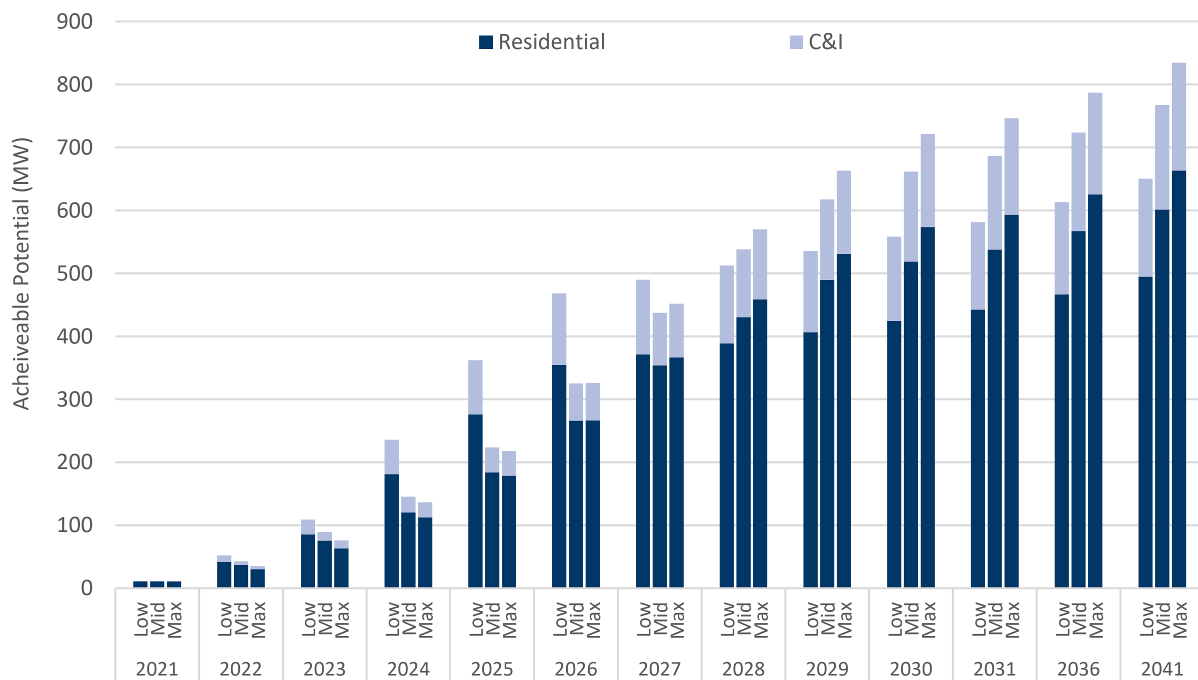


Figure 6 – DEP potential in each study year by scenario

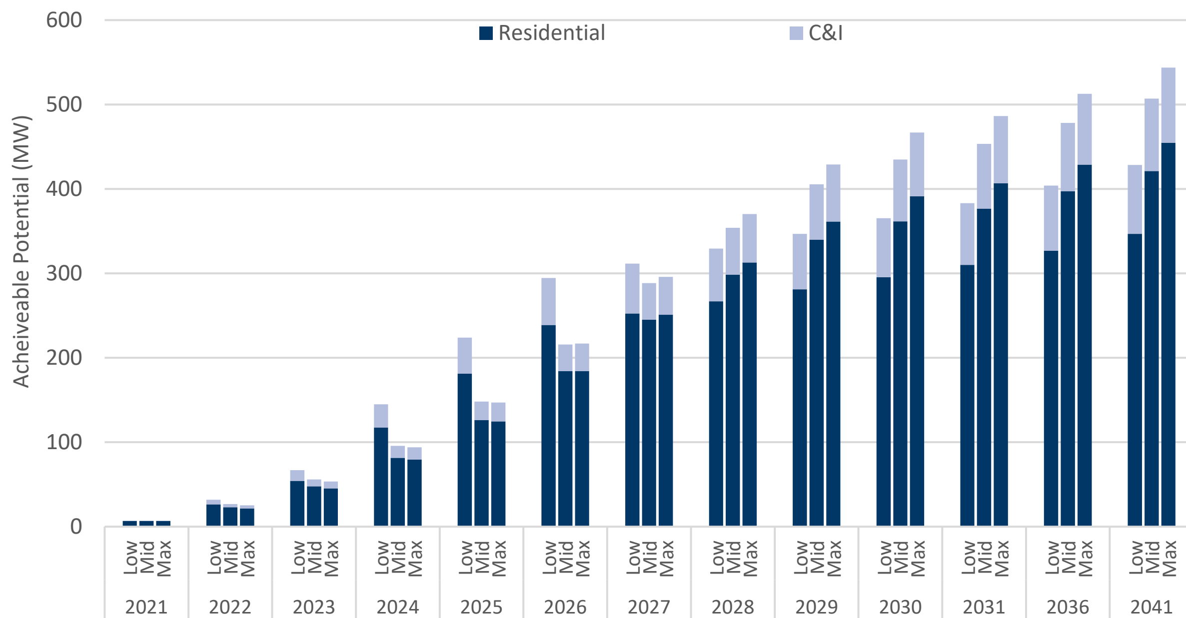
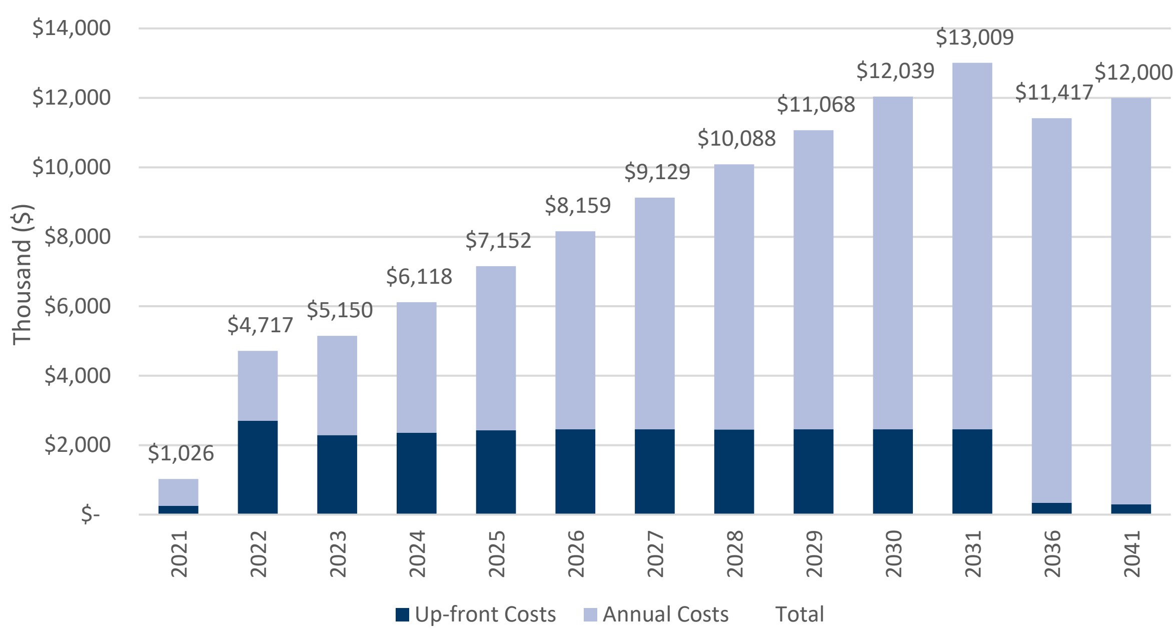


Figure 7 and Figure 8 below provide the program costs for mechanical solutions, broken down by upfront measure costs[10], and program administration costs and customer incentives. The set of mechanical solutions measures are constant throughout all scenarios. The results show higher up-front costs in the initial development years as new programs are developed, new customers are enrolled in the programs and new controls systems are put in place.

Figure 7 – DEC Mechanical Solutions Costs



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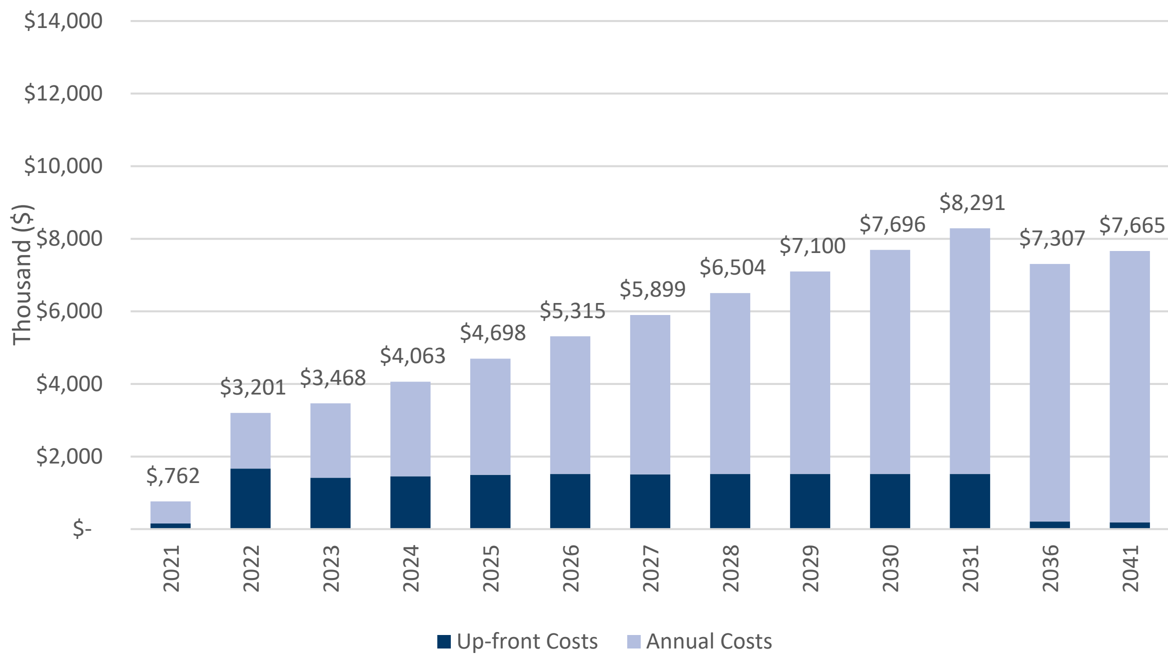
[10] Upfront measure costs include sign-up (enrollment) incentive costs, as well as controls and equipment installation costs.

Figure 8 – DEP Mechanical Solutions Costs



The Utility Cost Test (UCT) results assume that participants will stay enroll for 10 or 11 years, depending on the expected measure life. Table 8 provides cost-effectiveness results based on a program lifetime basis.

Table 8 – DEC Demand Response UCT Results

Programs	Measure/Program Life	UCT (at full deployment - 2026)
Residential Rate-Enabled T-Stat	11	3.2
Residential BYOT	4	4.9
Residential Rate-Enabled HWH	11	1.3
WP/HP Tune-up	10	2.0
Commercial Rate-Enabled T-Stat	10	2.7
Commercial BYOT	4	3.6
Residential BYOB	10	0.5
ADR	10	4.1

Table 9 – DEP Demand Response UCT Results

Programs	Measure/Program Life	UCT (at full deployment - 2026)
Residential Rate-Enabled T-Stat	11	2.3
Residential BYOT	4	3.7
Residential Rate-Enabled HWH	11	1.0
WP/HP Tune-up	10	1.2
Commercial Rate-Enabled T-Stat	10	1.6
Commercial BYOT	4	2.2
Residential BYOB	10	0.3
ADR	10	2.8

All modelled measures were cost-effective on a lifetime basis except for residential battery energy storage. This measure is cost-effective at measure level but fails the test at program level due to the costs required for running the program (fixed program costs) because it is assumed that there are a small number of residential battery systems currently installed among Duke's residential customers.

The impacts assessed for each scenario on the standard winter peak day in 2031 are shown in Figure 9 and Figure 10, where all programs are at full deployment. The assessment reveals that the combined impacts of the DSM rates and measures are not sufficient to alter the timing of the winter peak on the standard peak day. Thus, the net potential, is assessed as the achieved load reduction at the identified peak hours. For DEC, the load is nearly flat from 7:00 to 8:59, emphasizing the importance to target not only the peak hour, but the whole peak.[11]

[11] Our definition of peak did not consider wholesale transactions because the EE and DSM programs included in the solution set will not be available to this market

Figure 9 – DEC: Scenario Impact on Peak Day Load Shape (2031)

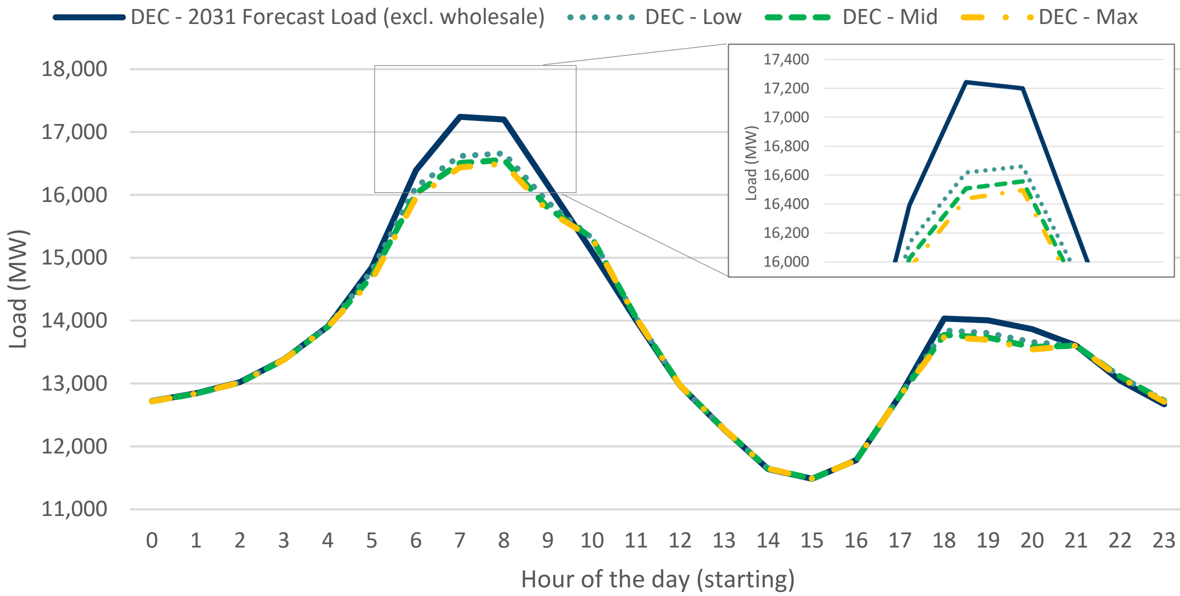
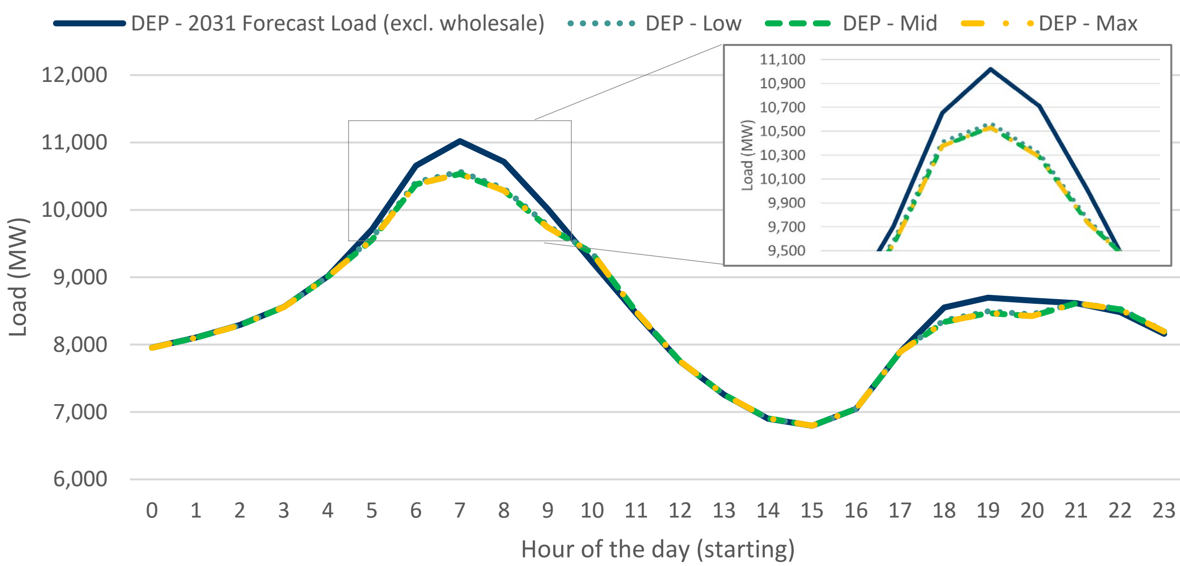


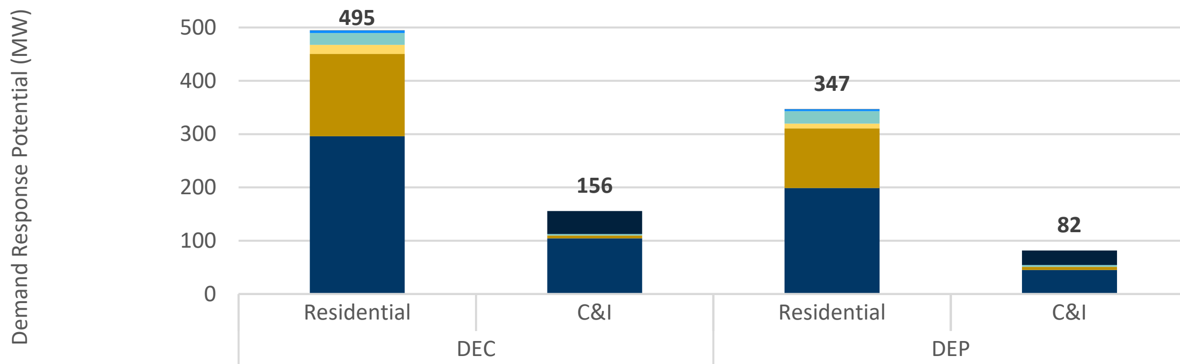
Figure 10 – DEP: Scenario Impact on Peak Day Load Shape (2031)



3.1 LOW SCENARIO

The Low scenario captures the DSM potential from two DSM rates options evaluated under the Flex Savings Options Pilot: TOU and TOU+CPP, in combination with the proposed set of mechanical solutions, thereby assessing rates that can be relatively quickly deployed. Figure 11 shows that DEC and DEP can respectively achieve 651 MW and 428 MW in winter peak reductions by 2041. Overall, the rate solutions and the residential Bring Your Own Thermostat (BYOT) program together account for more than 80% of the DSM potential.

Figure 11 – Low Scenario Achievable DSM Potential (2041) *



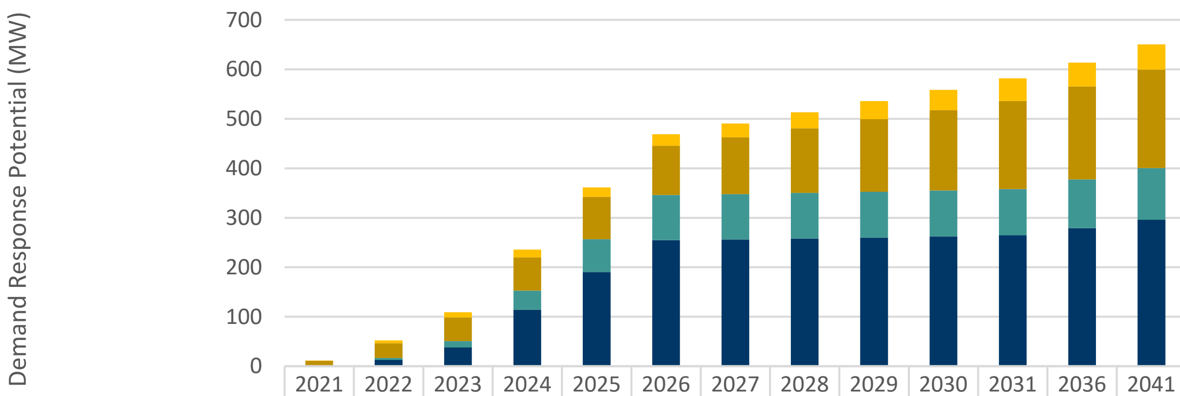
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	495	156	347	82
ADR		43		27
Battery Storage	0.4		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	22	3	23	3
Rate-enabled HWH	17		9	
BYOT	154	5	112	6
Rate Solution	296	105	199	45

* Due to rounding, numbers may not add up

Reviewing of the above chart, along with the detailed results provided in the appendix, a range of observations to focus on become apparent regarding future opportunities for Duke DSM programs. Although the TOU+CPP rate option accounts for 60% of the customer enrollment, it composed about 85% of the residential DSM rate savings, providing significantly more savings per customer than TOU. High savings from TOU+CPP participants are consistent with the preliminary results from the Flex Savings Options Pilot. Rate-enabled solutions, for both thermostats and water heaters account for a further 7% for the savings, reaching 72 MW in 2041. The residential BYOT program is already offered for summer peak reduction purposes and is in-process of being expanded to the winter season, offering an immediate expansion of winter peak reductions until new DSM rates can be successfully deployed.

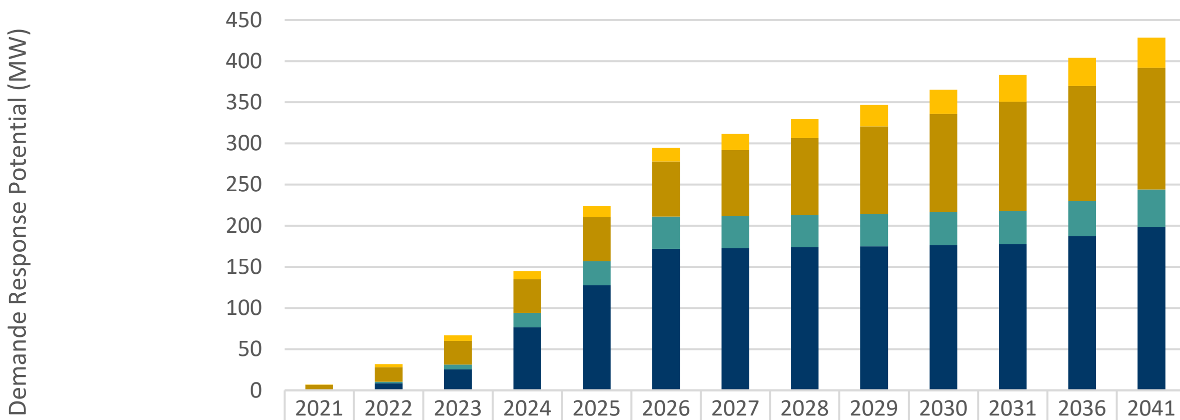
Figure 12 and Figure 13 below present the DSM solution ramp-up from 2021 to 2031, where all programs are at full deployment. The programs then continue to scale with load growth until 2041.

Figure 12 – DEC - Low Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	1	6	11	16	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	29	47	67	85	99	115	131	146	162	178	188	199
C&I - Rates	0.0	4.3	12.9	38.8	66.3	91.3	91.6	92.1	92.7	93.0	93.5	98.6	104.6
Residential - Rates	0	13	38	114	190	255	256	258	260	262	265	279	296

Figure 13 – DEP - Low Scenario Deployment

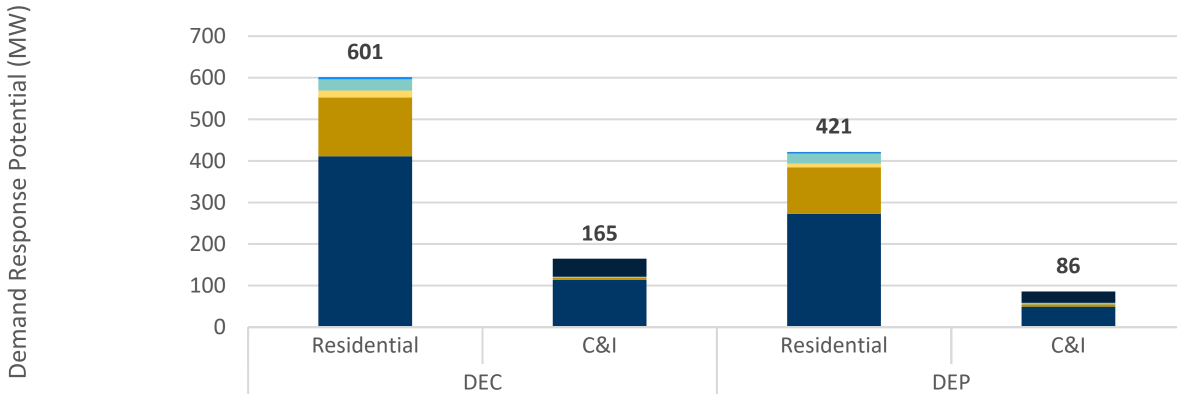


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	80	93	106	119	132	140	148
C&I - Rates	0.0	1.9	5.8	17.5	29.3	39.2	39.3	39.5	39.6	40.3	40.5	42.7	45.2
Residential - Rates	0	8	25	77	128	172	173	174	175	176	178	187	199

3.2 MID SCENARIO

The Mid scenario includes the DSM potential from the Low scenario, while adding a new residential rate option (Bill certainty with PTR) which targets risk averse customers. Adoption from small C&I is also increased, while PTR incentives for medium and large customers are doubled to $60/kW. Figure 14 below shows the breakdown of savings from the Mid scenario, wherein the overall achievable potentials for DEC and DEP in 2041 are 766 MW and 507 MW, respectively. With the addition of a new residential rate, rate solutions (residential and C&I) and BYOT now collectively account for over 85% of the DSM potential.

Figure 14 – Mid Scenario Demand Response Potential (2041) *



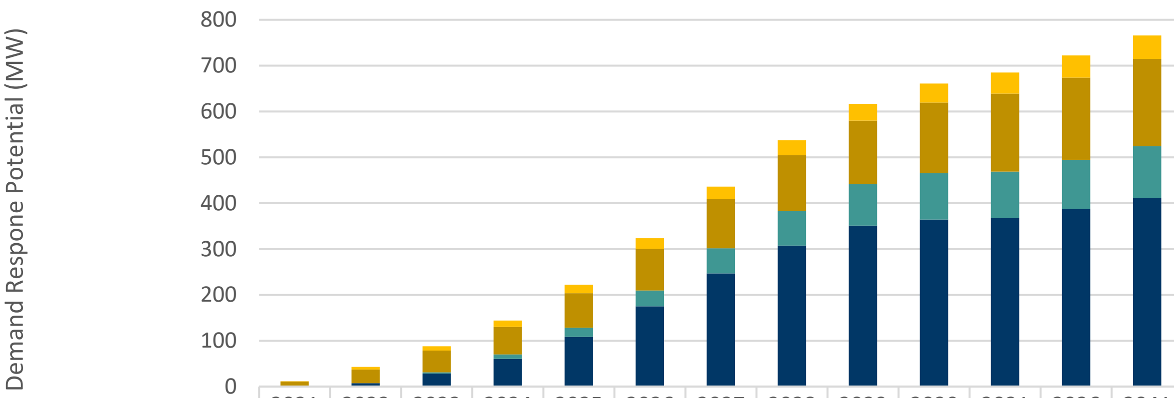
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	601	165	421	86
ADR		43		27
Battery Storage	0.5		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	27	3	24	3
Rate-enabled HWH	17		9	
BYOT	141	5	112	6
Rate Solution	411	113	272	49

* Due to rounding, numbers may not add up

The new Bill certainty with PTR rate option, accounts for a little under 30% of the residential rate savings potential and for most of the additional potential under residential rate solution in the Mid scenario. Despite the increase to the potential for the small C&I segment (i.e., from 9.0 MW in the Low scenario to 13.4 MW in the Mid scenario), overall, it has a limited impact on the total potential, which may not make this market segment a strong candidate for short-term program expansion. Finally, doubling the incentives to $60/kW for the medium and large C&I PTR program has limited impact, increasing the PTR potential by just 10%, while program costs increased by over 80%.

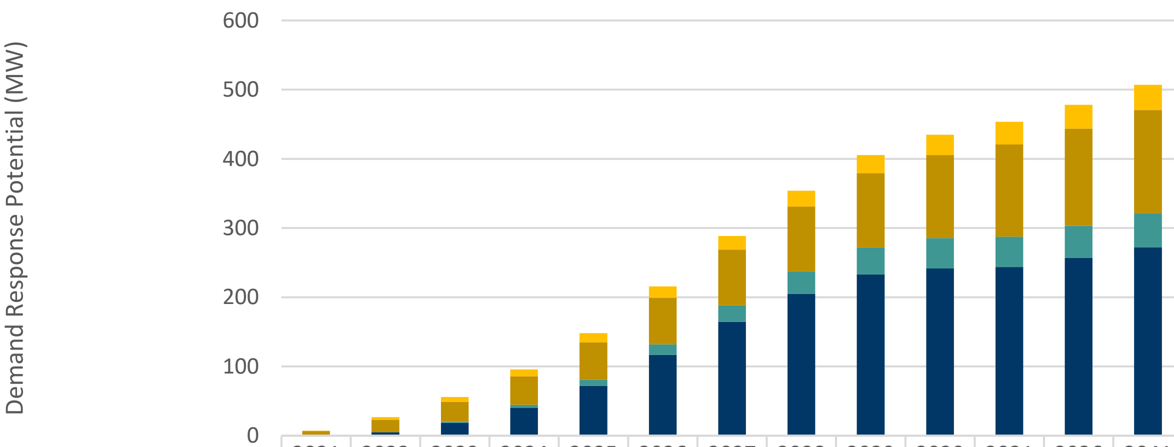
Figure 15 and Figure 16 below present the annual achievable potential, from 2021 to 2041. Program roll-out is extended compared to the Low scenario, to account for the time needed to implement the new rate option.

Figure 15 – DEC - Mid Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	1	6	9	14	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	29	47	60	75	91	107	123	138	154	170	179	190
C&I - Rates	0.0	0.0	2.9	9.8	19.7	34.6	54.7	74.9	90.4	101.0	101.4	106.9	113.4
Residential - Rates	0	8	28	61	109	175	247	308	351	364	368	388	411

Figure 16 – DEP - Mid Scenario Deployment

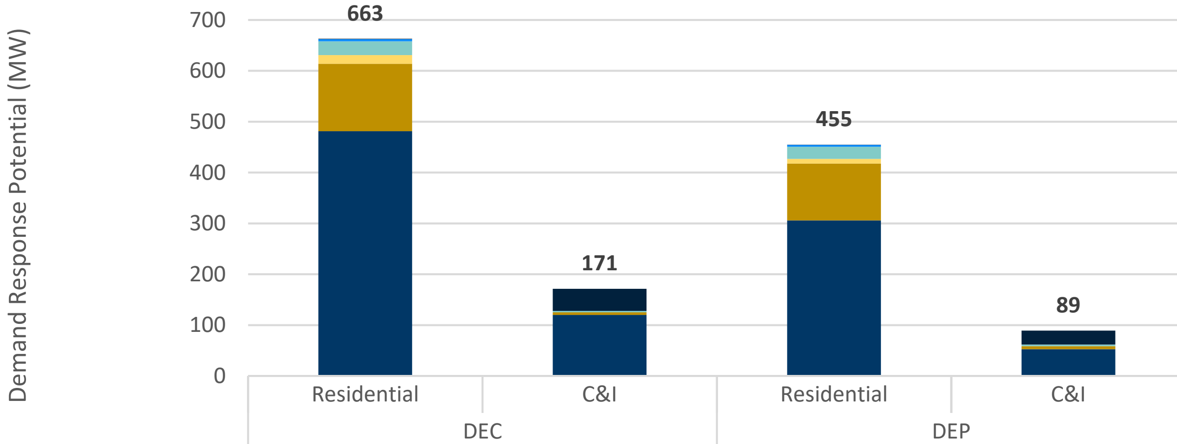


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	81	94	107	120	133	140	149
C&I - Rates	0.0	0.0	1.3	4.3	8.6	15.1	23.8	32.6	39.3	43.9	44.0	46.4	49.2
Residential - Rates	0	5	19	40	72	117	165	205	233	242	244	257	272

3.3 MAX SCENARIO

The Max scenario aims to maximize the DSM rates potentials, and to assess the impact of offering the highest possible PTR incentives. A new CPP with flat volumetric rate is added to complement the residential rates included in the Mid scenario. In the Max scenario a complete set of residential rates options is offered ranging from low risk (Bill certainty with PTR) to high risk (TOU+CPP). In the C&I sector, the small C&I adoption was raised while incentives for medium and large C&I PTR were raised to their maximum level, while maintaining program cost-effectiveness. Figure 17 shows that DEC and DEP can respectively achieve 834 MW and 544 MW by 2041. With the addition of another new residential rate, collectively the rate solutions (residential and C&I) and BYOT now account for over 87% of the DSM potential.

Figure 17 – Max Scenario Demand Response Potential (2041) *



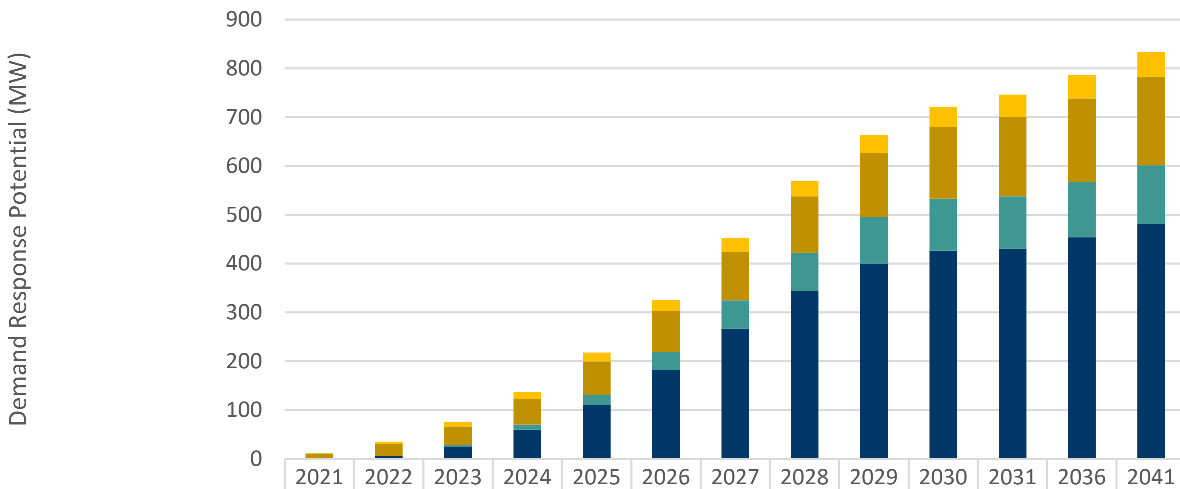
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	663	171	455	89
ADR		43		27
Battery Storage	0.5		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	27	3	24	3
Rate-enabled HWH	17		9	
BYOT	133	5	112	6
Rate Solution	481	120	306	53

* Due to rounding, numbers may not add up

Like the Mid scenario findings, the increase in adoption among small C&I customers and the increase in PTR incentives for the medium and large C&I customers resulted in limited additional uptake. The C&I sector potential reaches just 265 MW under the Max scenario (DEC and DEP combined) compared to the 241 MW in the Low scenario. The Max scenario residential rate potential presents a 39% increase over the Low scenario and a 17% increase compared to the Mid scenario. The breakdown of savings among the DSM rates is similar for both DEC and DE, with the TOU+CPP rate and Bill certainty with PTR each accounting for over 30% of the overall DSM rates savings.

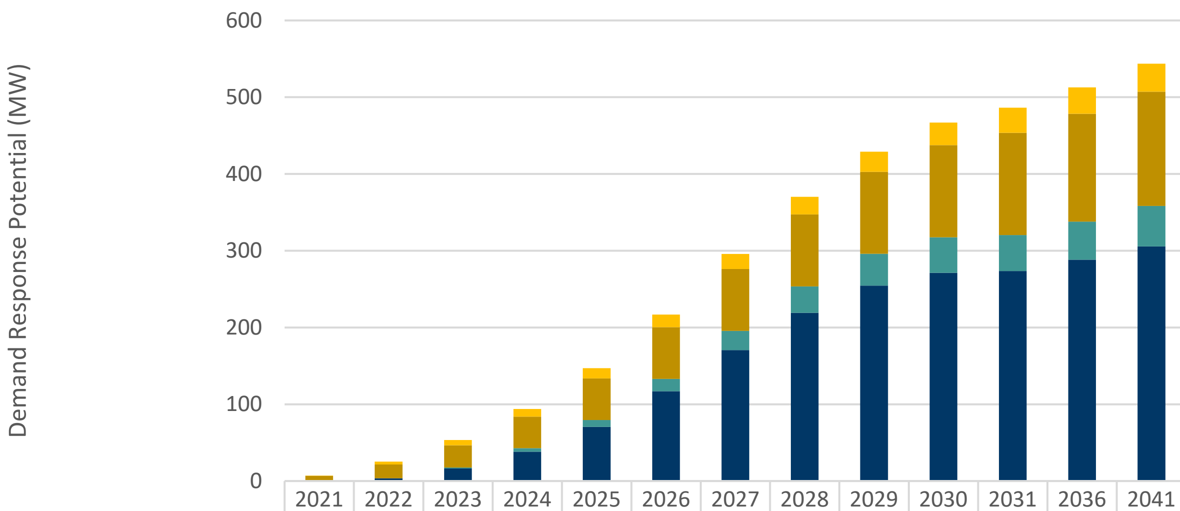
Figure 18 and Figure 19 below present the in each year from 2021 to 2041. As for the Mid scenario, program roll-out is extended to allow for the time needed to deploy additional new rate options.

Figure 18 – DEC - Max Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	5	9	14	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	25	38	52	68	84	100	115	131	147	163	171	182
C&I - Rates	0	0	3	10	21	37	58	79	95	107	107	113	120
Residential - Rates	0	6	25	60	111	183	267	343	400	427	430	454	481

Figure 19 – DEP - Max Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	81	94	107	120	133	140	149
C&I - Rates	0	0	1	5	9	16	25	34	41	46	47	50	53
Residential - Rates	0	4	16	38	70	117	170	219	255	271	273	288	306

3.4 COMPARISON WITH DUKE'S MARKET POTENTIAL STUDY (MPS)

The goal of this study is to assess possible strategies that could allow Duke Energy to expand its winter peak reduction potential. To that end, it focuses on a small set of specific mechanical and rates solutions specifically selected for their ability to address winter peak loads. It is important to note that the study does not include all available mechanical solutions and therefore differs from the MPS conducted by

Nexant. Conversely, the MPS study focused on the achievable potential related to all mechanical solutions and did not assess any rate structure impacts.

Table 10 and Table 11 below show a high-level comparison between the MPS[12],[13] results and the modelled solution set. In both studies, the DSM potentials assessed are incremental to Duke's current winter peak DSM program impacts.

Table 10: Achievable Potential Comparison - Max Scenario and MPS Enhanced scenario (DEC)

	DEC - 2041 Max Scenario	MPS – DEC (Base – 2041)	MPS – DEC (Enhanced – 2041)
Potential Total (MW)	**834**	**403**	**488**
C&I	Rates: 120	38	69
	Mechanical: 51		
Residential	Rates: 481	0	0
	Mechanical: 182	365	419

Table 11: Achievable Potential Comparison - Max Scenario and MPS Enhanced scenario (DEP)

	DEP - 2041 Max Scenario	MPS – DEP (Base – 2041)	MPS – DEP (Enhanced – 2041)
Potential Total (MW)	**544**	**273**	**307**
C&I	Rates: 53	3	5
	Mechanical: 36		
Residential	Rates: 306	0	0
	Mechanical: 149	270	302

For the C&I market, this study estimates rate and mechanical potential separately and shows the impact mechanical solutions and rates not considered in the MPS and are therefore incremental to that study. For the residential sector, the potential in this study is also incremental to the MPS and outlines a plan to operationalize a more specific set of high value technologies and new rates not considered in the MPS. Additionally, the MPS excluded DSM rider opt-out customers while this study considers that a PTR rate structure could potentially attract some of those customers (between 5% and 9% depending on the rate class and scenario).

[12] DEC values are from is Duke Energy North Carolina EE and DSM Market Potential Study, May 2020, Figure 7-21 DEC DSM Winter Peak Capacity Program Potential and Duke Energy South Carolina EE and DSM Market Potential Study, April 2020. Figure 7-20 DEC DSM Summer Peak Capacity Program Potential

[13] DEP values are from is Duke Energy North Carolina EE and DSM Market Potential Study, May 2020, Figure 7-23 DEP DSM Winter Peak Capacity Program Potential and Duke Energy South Carolina EE and DSM Market Potential Study, April 2020. Figure 7-23 DEP DSM Summer Peak Capacity Program Potential

4 KEY TAKE-AWAYS

Based on the results of the winter peak demand reduction potential assessment, there is an apparent 1,378 MW (Max Scenario –DEC and DEP combined) of winter season DSM potential by 2041 representing 4.3% and 4.4% of the DEC and DEP forecasted load, respectively.

As shown in Table 12, most of this potential can be achieved via the residential sector using new rates and expanding mechanical solutions. A smaller portion of the DSM potential can be achieved by increasing incentives to drive program adoption and by diversifying rate structures.

Table 12 – Achievable DSM Potential in 2041, by Scenario (MW)

	Low Scenario	Mid Scenario	Max Scenario
Total Achievable Potential	**1,079 MW**	**1,273 MW**	**1,378 MW**
DEC Achievable Potential	651 MW (495 Res/156 C&I)	766 MW (601 Res/165 C&I)	834 MW (663 Res/171 C&I)
DEP Achievable Potential	428 MW (347 Res/82 C&I)	507 MW (421 Res/86 C&I)	544 MW (455 Res/89 C&I)

Table 13 below benchmarks the achievable DSM potential from the Mid and Max scenarios to DSM potential study findings in other jurisdictions. Overall, these show that the Duke DSM potential is like other winter peaking jurisdictions, where the industrial portion of the utility peak load is moderate and avoided costs are low, as is the case for Duke Energy.

Table 13 – Benchmarking of the Achievable DSM Potential (Mid-Max Scenarios) to Winter Peaking Jurisdictions

	Duke Energy (2020)	Newfoundland and Labrador (2019)	Puget Sound Energy (2017)	Northwest Power & Cons. Council (2014)
Portion of Peak Load	DEC: 4.0% - 4.3% DEP: 4.1% - 4.4% (2041)	10.4%[14] (15-year outlook)	3.7% (20-year outlook)	8.8% (15-year outlook)

Based on the findings in this report three key take-aways emerge:

- **Residential sector programs are key to achieve significant winter demand reduction potentials.** Across all scenarios, the residential sector shows three to four times more potential than the C&I

[14] The share of curtailable industrial load contributing to the utility peak load in Newfoundland and Labrador is high.

sector. This is driven primarily by seasonal variation in the residential sector demand curves, which results from the relatively high penetration of electric heating in the residential sector, while the C&I sector exhibits flatter variations on a daily and inter-seasonal basis.

Duke's current winter residential DSM offering is limited to DEP NC in the Company's Western Region service territory in the area surrounding Asheville[15] and the results of this study indicate that there is potential to expand residential Duke's winter DSM programs. Residential savings are derived from both mechanical and DSM rate solutions, and will likely take time to implement, in some cases requiring regulatory approval for new rates and pilots and programs.

- **Duke should consider pursuing some quick wins in the immediate term, followed by the addition of more complex and varied rate options.**

  On the residential side, a winter BYOT program can likely be implemented as the lowest-hanging fruit option, by adapting the existing summer peak BYOT program to include winter peak events.

  Following that, TOU and TOU+CPP rate designs could be implemented, pending positive results from the Flex Savings Options Pilot conclusions. Bill certainty + PTR and a Flat volumetric + CPP rate option can also be developed as near-term options to capture residential winter peak reduction potential.

  On the C&I side, implementing a PTR rate structure can achieve higher potential reduction than adding other new DSM programs. As a second step, adding Automated Demand Response solutions could enhance current DSM programs.

- **Changes to PTR incentive levels have very little impact on medium and large C&I customer potentials.** Most of the achievable DSM potential (91%) for medium and large customers is achievable with the low scenario incentives ($30 per kW).

Overall, it appears that expanding to new programs and rates could have an important role in increasing Duke winter peak DSM potential in both the DEC and DEP systems.

[15] This program, funded through Rider LC-WIN-2B, installs controls to (1) interrupt service to all resistance heating elements installed in approved central electric heat pump units with strip heat and/or (2) interrupt service to each installed, approved electric water heater. In addition, a winter BYOT filing has been made but has not yet been operationalized as of the time of this study being published

A.1 RESULTS BREAKDOWN BY RATE CLASS

Table A-1 – Scenario 1 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	3	9	15	21	21	21	21	21	21	22	22	22	22	22	23	23	23	24	24
			TOU+CPP - Res	0	7	22	67	112	151	152	153	154	155	156	158	159	161	163	165	167	169	171	173	175
		Businesses	PTR - SGS	0.0	0.1	0.4	1.2	2.0	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.0
			PTR - Medium and Large C&I	0	2	5	16	27	37	37	37	37	38	38	38	38	39	39	40	40	41	41	42	42
	DEC	Residential	TOU - RE	0	2	5	15	25	33	34	34	34	34	35	35	35	36	36	37	37	37	38	38	39
			TOU+CPP - RE	0	7	21	64	106	142	143	144	145	146	148	149	150	152	154	156	157	159	161	163	165
			TOU - RS	0.0	0.3	0.9	2.7	4.5	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.8	6.9	7.0
			TOU+CPP - RS	0	4	11	33	55	73	74	74	75	75	76	77	78	78	79	80	81	82	83	84	85
		Businesses	PTR - SGS	0.0	0.3	0.8	2.3	3.8	5.1	5.1	5.2	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			PTR - Medium and Large C&I	0	4	12	37	62	86	86	87	87	88	88	89	90	91	92	93	94	95	96	98	99
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	12	14	16	19	21	21	21	21	22	22	22	22	23	23	23
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	3	6	9	10	9	12	14	16	18	20	20	20	20	21	21	21	21	22	22	22
			Res. Wi-Fi T-Stat	11	23	37	51	67	80	91	103	115	126	138	139	141	142	144	146	147	149	151	153	154
			Res. HP Tune-up	0	1.6	2.0	2.4	2.7	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.2	2.5	3.8	5.2	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
		Businesses	Comm. Rate-Enabled T-Stat	0	0.7	1.1	1.5	1.8	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.6	1.3	2.0	2.7	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

Table A-2 – Scenario 2 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	2	4	7	11	16	19	21	21	21	22	22	22	22	22	23	23	23	24	24
			TOU+CPP - Res	0	4	15	30	52	83	114	138	154	155	156	158	159	161	163	165	167	169	171	173	175
			Bill Certainty + PTR - Res	0	0	2	6	13	22	35	48	58	65	66	66	67	68	69	69	70	71	72	73	74
		Businesses	Bill Certainty + PTR - SGS	0.0	0.0	0.1	0.4	0.8	1.4	2.2	3.0	3.6	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6
			PTR - Medium and Large C&I	0	0	1	4	8	14	22	30	36	40	40	40	41	41	42	42	43	43	44	44	45
	DEC	Residential	TOU - RE	0	1	3	7	12	18	25	30	34	34	35	35	35	36	36	37	37	37	38	38	39
			TOU+CPP - RE	0	4	14	28	50	78	107	130	145	146	148	149	150	152	154	156	157	159	161	163	165
			Bill Certainty + PTR - RE	0	0	2	8	15	27	43	59	71	80	80	81	82	83	84	85	86	87	88	89	90
			TOU - RS	0.0	0.2	0.6	1.2	2.1	3.3	4.5	5.5	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.8	6.9	7.0
			TOU+CPP - RS	0	2	7	15	26	40	55	67	75	75	76	77	78	78	79	80	81	82	83	84	85
			Bill Certainty + PTR - RS	0	0	1	2	4	8	12	17	20	22	23	23	23	23	24	24	24	24	25	25	25
		Businesses	PTR - SGS	0.0	0.0	0.2	0.8	1.5	2.7	4.2	5.8	7.0	7.9	7.9	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9
			PTR - Medium and Large C&I	0	0	3	9	18	32	51	69	83	93	93	94	95	96	97	99	100	101	102	103	104
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	13	15	17	19	22	22	22	22	22	23	23	23	24	24	24
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	3	6	7	9	11	14	16	19	21	24	24	24	25	25	25	26	26	26	27	27
			Res. Wi-Fi T-Stat	11	23	36	46	58	69	81	92	103	115	126	127	128	130	131	133	135	136	138	140	141
			Res. HP Tune-up	0	1.6	1.6	1.9	2.3	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.2	2.9	4.4	6.0	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
		Businesses	Comm. Rate-Enabled T-Stat	0	0.7	0.6	0.8	1.1	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.6	1.3	1.1	1.5	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

Table A-3 – Scenario 3 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	3	6	10	16	23	27	30	31	31	31	31	32	32	33	33	33	34	34	35
			TOU+CPP - Res	0	3	9	18	32	51	69	84	94	95	95	96	97	98	99	101	102	103	104	106	107
			Bill Certainty + PTR - Res	0	0	2	8	16	27	43	59	72	80	81	82	83	83	84	85	86	87	89	90	91
			Flat Volumetric + CPP - Res	0	0	2	6	13	22	35	48	58	65	66	67	67	68	69	70	70	71	72	73	74
		Businesses	Bill Certainty + PTR - SGS	0.0	0.0	0.2	0.5	1.0	1.8	2.9	4.0	4.8	5.4	5.4	5.5	5.5	5.6	5.7	5.7	5.8	5.9	6.0	6.0	6.1
			PTR - Medium and Large C&I	0	0	1	4	8	14	22	30	37	41	42	42	42	43	43	44	44	45	45	46	46
	DEC	Residential	TOU - RE	0	1	4	9	15	24	33	39	44	44	45	45	46	46	47	47	48	48	49	50	50
			TOU+CPP - RE	0	3	9	18	32	51	70	84	94	95	96	97	98	99	100	101	102	104	105	106	107
			Bill Certainty + PTR - RE	0	0	3	10	19	34	53	73	89	100	100	101	102	103	105	106	107	108	110	111	112
			Flat Volumetric + CPP - RE	0	0	3	8	17	30	47	64	78	87	88	89	90	91	92	93	94	95	96	98	99
			TOU - RS	0.0	0.2	0.6	1.3	2.3	3.6	4.9	5.9	6.6	6.7	6.7	6.8	6.9	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.5
			TOU+CPP - RS	0	1	4	9	16	25	34	41	46	46	46	47	47	48	48	49	50	50	51	51	52
			Bill Certainty + PTR - RS	0	0	1	3	6	10	16	21	26	29	29	30	30	30	31	31	31	32	32	32	33
			Flat Volumetric + CPP - RS	0	0	1	2	4	6	10	14	16	18	19	19	19	19	19	20	20	20	20	21	21
		Businesses	PTR - SGS	0.0	0.0	0.3	1.0	2.0	3.6	5.6	7.7	9.4	10.5	10.6	10.7	10.8	10.9	11.0	11.2	11.3	11.4	11.6	11.7	11.8
			PTR - Medium and Large C&I	0	0	3	9	19	33	52	72	86	96	97	98	98	100	101	102	103	104	106	107	108
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	13	15	17	19	22	22	22	22	22	23	23	23	24	24	24
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	2	4	7	9	11	14	16	19	21	24	24	24	25	25	25	26	26	26	27	27
			Res. Wi-Fi T-Stat	11	19	29	39	51	62	73	85	96	107	119	120	121	122	123	125	126	128	130	131	133
			Res. HP Tune-up	0	1.3	1.6	1.9	2.3	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.4	2.9	4.4	6.0	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.6	0.8	1.1	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.3	0.7	1.1	1.5	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

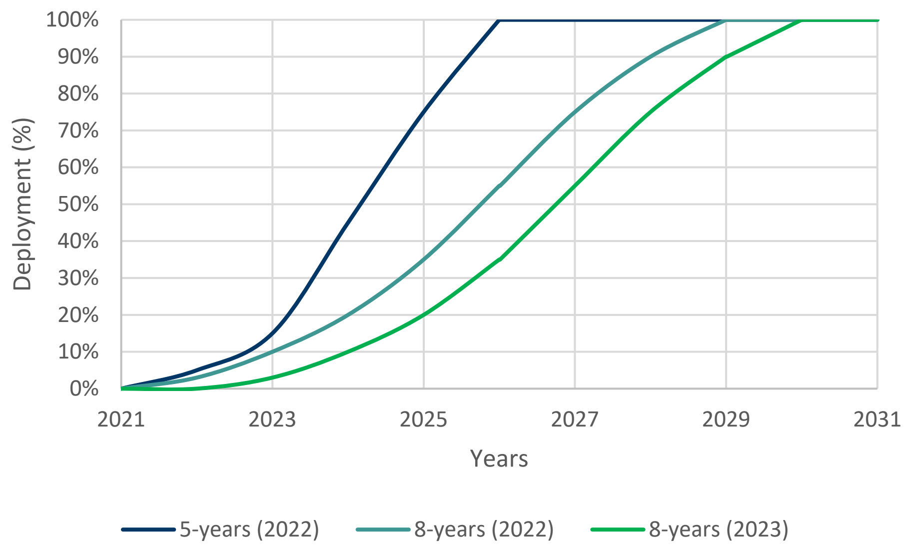
A.2 PROGRAM RAMP-UP AND COSTS

RAMP-UP

Ramp-up rates were created using s-curves over 5 and 8 years.

The low scenario, which is easier to implement, includes a ramp-up over 5 years. Scenarios Mid and Max, which requires more rates designs, assume a ramp-up over 8 years before full deployment of the rate solutions. Furthermore, rates that where included in the pilot (TOU and TOU+CPP) are estimated to launch in 2022, while bill certainty + PTR and flat volumetric + CPP are starting in 2023. The figure below summarized the ramp-up.

Figure A-1 – Enrollment Ramp-up: Rates



PROGRAM COSTS

Estimated program costs for the mechanical solution set are presented in the table below.

Table A-4: Program Costs

Program Name	Development Costs	Program Fixed Annual Costs	Other Costs ($/customers) for marketing, IT, admin
Residential Rate-Enabled T-Stat	$200,000	$100,000	$40
Residential BYOT	$100,000	$100,000	$40
Residential Rate-Enabled HWH	$175,000	$75,000	$35
WP/HP Tune-up	$175,000	$100,000	$0
Commercial Rate-Enabled T-Stat	$150,000	$75,000	$40
Commercial BYOT	$75,000	$75,000	$40
Residential BYOB	$100,000	$100,000	$30
ADR	$250,000	$150,000	$20

A.3 KEY ASSUMPTIONS

ECONOMIC ASSUMPTIONS

The avoided costs provided by Dukes for South and North Carolina were blended between South and North Carolinas to obtain an average avoided cost for each system. These avoided costs are presented in the table below, in 2021 dollars. This study uses also uses blended discount rates of 6.9% (DEC) and 6.8% (DEP).

Table A-5 – Avoided Costs

Year	DEC - Avoided cost ($/kW)	DEP - Avoided cost ($/kW)
2021	129.5	100.6
2022	131.6	102.1
2023	133.9	103.8
2024	136.3	105.5
2025	138.8	107.2
2026	141.3	108.9
2027	144.0	110.8
2028	146.7	112.6
2029	149.5	114.5
2030	152.3	116.5
2031	155.1	118.4
2032	157.9	120.3
2033	160.7	122.3
2034	163.6	124.3
2035	166.5	126.3
2036	169.5	128.3
2037	172.5	130.4
2038	175.6	132.5
2039	178.8	134.7
2040	182.0	136.9
2041	185.3	139.1
2042	188.6	141.4
2043	192.1	143.8
2044	195.5	146.1
2045	199.1	148.5

SEGMENTATION AND END USE

The follow ratios where used to breakdown the potential by State.

Table A-6 – Segmentation by State

State	DEC	DEP
North Carolina	73.50%	85%
South Carolina	26.50%	15%

To obtain a breakdown per rate and per end use, the latest EIA's CBECS (2012) and RECS (2015) data was used. This data was combined with Duke's 2017 and 2018 annual consumption and average consumption per customer for each rate class to obtain the following tables.

Table A-7 – DEC segmentation assumptions

Segment	Share of Primary Space Heating Electric (%)	Share of Primary Hot Water Electric (%)	Average Annual Consumption (kWh)	Population
SGS	64%	78%	18,049	324,972
LGS	64%	78%	536,989	11,431
OPTC	64%	78%	745,677	21,133
OPTI	64%	78%	11,394,026	1,642
Other	64%	78%	412,306	7005
RS	24%	52%	12,866	1,295,393
RE	100%	100%	13,485	946,860

Table A-8 – DEP segmentation assumptions

Segment	Share of Primary Space Heating Electric (%)	Share of Primary Hot Water Electric (%)	Average Annual Consumption (kWh)	Population
SGS	64%	78%	14,379	201,554
MGS	64%	78%	372,588	33,267
LGS	64%	78%	17,371,855	255
RTP	64%	78%	68,103,493	90
Other	64%	78%	62,518	1159.44
Res	63%	72%	13,951	1,322,187

The EIA's building archetypes where used to generate 8760h annual load curve to model consumption for each rate class.

Table A-9 – DEC building archetypes included per rates

EIA's Archetypes	Segment						
	RS	RE	SGS	LGS	OPTC	OPTI	Other
Hospital	-	-	-	Yes	Yes	Yes	Yes
Hotel Small	-	-	Yes	-	-	-	-
Industrial	-	-	-	Yes	Yes	Yes	Yes
MF_Elec. Resistance	Yes	Yes	-	-	-	-	-
MF_HP	Yes	Yes	-	-	-	-	-
Office Large	-	-	-	Yes	Yes	Yes	Yes
Office Medium	-	-	Yes	Yes	Yes	Yes	Yes
Office Small	-	-	Yes	-	-	-	-
Outpatient Healthcare	-	-	Yes	-	-	-	-
Restaurant Fast Food	-	-	Yes	-	-	-	-
Restaurant Sit Down	-	-	Yes	-	-	-	-
Retail Standalone	-	-	Yes	-	-	-	-
Retail Strip Mall	-	-	Yes	-	-	-	-
School Primary		-	-	Yes	Yes	Yes	Yes
School Secondary	-	-	-	Yes	Yes	Yes	Yes
SF_Elec. Resistance	Yes	Yes	-	-	-	-	-
SF_HP	Yes	Yes	-	-	-	-	-
Supermarket	-	-	-	Yes	Yes	Yes	Yes
Warehouse	-	-	Yes	Yes	Yes	Yes	Yes

Table A-10 – DEP building archetypes included per rates

EIA's Archetypes	Segment					
	Res	SGS	MGS	LGS	RTP	Other
Hospital	-	-	Yes	Yes	Yes	Yes
Hotel Small	-	Yes	Yes	-	-	-
Industrial	-	-	-	Yes	Yes	Yes
MF_Elec. Resistance	Yes	-	-	-	-	-
MF_HP	Yes	-	-	-	-	-
Office Large	-	-	-	Yes	Yes	Yes
Office Medium	-	Yes	Yes	Yes	Yes	Yes
Office Small	-	Yes	-	-	-	-
Outpatient Healthcare	-	Yes	Yes	-	-	-
Restaurant Fast Food	-	Yes	Yes	-	-	-
Restaurant Sit Down	-	Yes	Yes	-	-	-
Retail Standalone	-	Yes	-	-	-	-
Retail Strip Mall	-	Yes	-	-	-	-
School Primary		-	Yes	Yes	-	Yes
School Secondary	-	-	Yes	Yes	-	Yes
SF_Elec. Resistance	Yes	-	-	-	-	-
SF_HP	Yes	-	-	-	-	-
Supermarket	-	-	Yes	Yes	Yes	Yes
Warehouse	-	Yes	Yes	Yes	Yes	Yes

RESIDENTIAL RATE DETAILS

TOU RATES

This rate targets consumers able to vary their daily usage to reduce energy costs. This new TOU structure is based on the Flex Savings Options pilot conducted by Nexant for Duke Energy Carolinas (NC). The pilot went into effect on October 1, 2019 and preliminary results were provided by Duke to inform our analysis. The pilot tested three different rates structures (TOU, CPP, TOUD) across three customer classes including all-electric residential (RE) and standard residential (RS).

- **Peak to off-peak ratio:** 1.7
- **Peak load impact**
  - Based on preliminary Flex Savings Options Pilot findings
  - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

TOU WITH CPP

This rate targets consumers who are highly attentive to their energy demand and can change their load in a significant manner. The modelled TOU with CPP rate structure is also based on the Flex Savings Options Pilot. Customers are on the previous TOU rate but with higher hourly prices during specific peak hours on about 20 days per year.

- **CPP Peak to off-peak ratios:** 3.2
- **Peak load impact**
  - Based on the preliminary Flex Savings Options Pilot findings
  - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

BILL CERTAINTY WITH PTR

This rate targets consumers who want to mitigate their billing risk. It offers a fixed bill per month, with a PTR on peak days.

- **Peak to off-peak ratios**
  - 3:1 savings ratio for all rates[16]
  - Bill certainty is not expected to increase the winter peak demand compared to a flat volumetric rate
- **Peak load impact**
  - Peak impact reduction was derived from the Arcturus[17] analysis on dynamic rates. This analysis evaluates the customer peak reduction to dynamic rates, covering more than 300 pricing treatments from over 60 pilots.

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

[17] Peak reduction from "Arcturus 2.0: A meta-analysis of time-varying rates for electricity", A. Faruqui, S. Sergici and C. Warner, 2017.

- Bounce back effects are derived from the Flex Savings Options Pilot findings (CPP), adjusted for savings.
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

FLAT VOLUMETRIC WITH CPP

This rate targets consumers who can change their load in a significant manner but are not willing to modify their everyday usage. It offers a fixed price per unit of energy consumed, with a CPP on peak days.

- **CPP peak to off-peak ratios:** 5.5
- **Peak load impact**
  - Based on the Flex Savings Options Pilot findings
  - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

It is important to note that all customers who are enrolled in one of the residential rates above and a rate-enabled mechanical solution (rate-enabled thermostats or hot water heater) have a reduced peak load impact, based on the peak load end use share of heating and hot water usage, to account for the fact that the load impact is considered in mechanical solutions, preventing any double counting.

NON-RESIDENTIAL RATES DETAILS

SMALL C&I CUSTOMERS – BILL CERTAINTY WITH PTR

Being a segment with historically low elasticity to electric demand, this rate was implemented as being the most consumer friendly, hoping to spur demand response. The rate offers a fixed bill per month, with a PTR on peak days.

- **Peak to off-peak ratios**
  - 3:1 saving ratio[18]
  - Peak impact reduction was also derived from the Arcturus[19] analysis on dynamic rates. This analysis evaluates the customer peak reduction to dynamic rates, covering more than 300 pricing treatments from over 60 pilots.
  - Bounce back effects apply the residential PTR shape, adjusted to savings levels derived for C&I customers.
- **Eligible Market**
  - Customers in either DEC – SGS or DEP – SGS

Although the Flex Savings Options Pilot also included customers from the SGS rate class, results were not yet available to integrate into our analysis. Instead, the Arcturus report was used, but savings were

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

[19] Peak reduction from "Arcturus 2.0: A meta-analysis of time-varying rates for electricity", A. Faruqui, S. Sergici and C. Warner, 2017.

reduced by 50% compared to residential customer response to account for the historically low elasticity of the small C&I sector.

MEDIUM AND LARGE C&I RATES – PTR

By using a carrot-only rebate approach, PTR rates is particularly attractive to large customers who see in it as a win-win situation. Considering the variety of C&I rates as well as the option for large customers to opt-out from DSM programs, this rate is potentially an opportunity to attract more customers than current DSM programs. The rate consists of offering a rebate for reducing their load below a customer-specific baseline during peak times.

- **Peak load impact**
  - Peak impact reduction was assessed based on an end-use approach where the percentage of achievable load curtailable by customer was evaluated for each major end-use. Baseline load curves are based on hourly average demand per customer class provided by Duke Energy.
- **Eligible Market**
  - All C&I customers can choose to enroll (DEC – LGS, DEC – OPTC, DEC-OPTI, DEC – Other, DEP MGS, DEP – LGS). It is assumed that a small portion of opt-out customers would choose to enroll in the rates (more details in the results section)
  - For modelling assumptions, to avoid any double-counting, participants already enrolled under current DSM programs (DRA or PowerShare) are excluded from the customers count.

This report was prepared by Dunsky Energy Consulting. It represents our professional judgment based on data and information available at the time the work was conducted. Dunsky makes no warranties or representations, expressed or implied, in relation to the data, information, findings and recommendations from this report or related work products.

Attachment 4
E-100, Sub 165

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DUKE ENERGY

Winter Peak Targeted DSM Plan

December 2020

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)

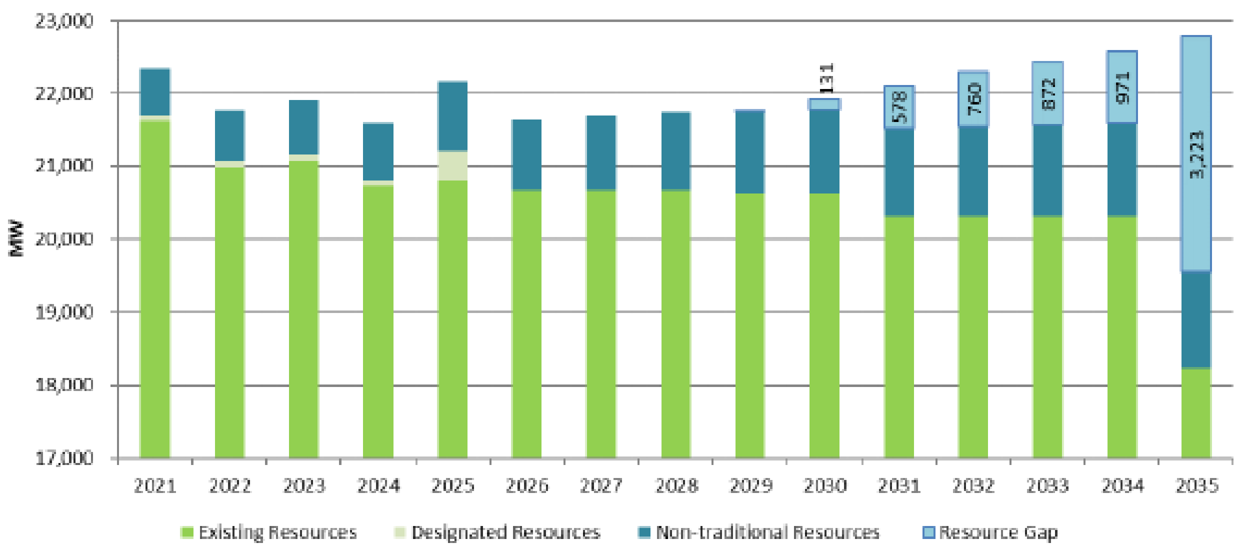
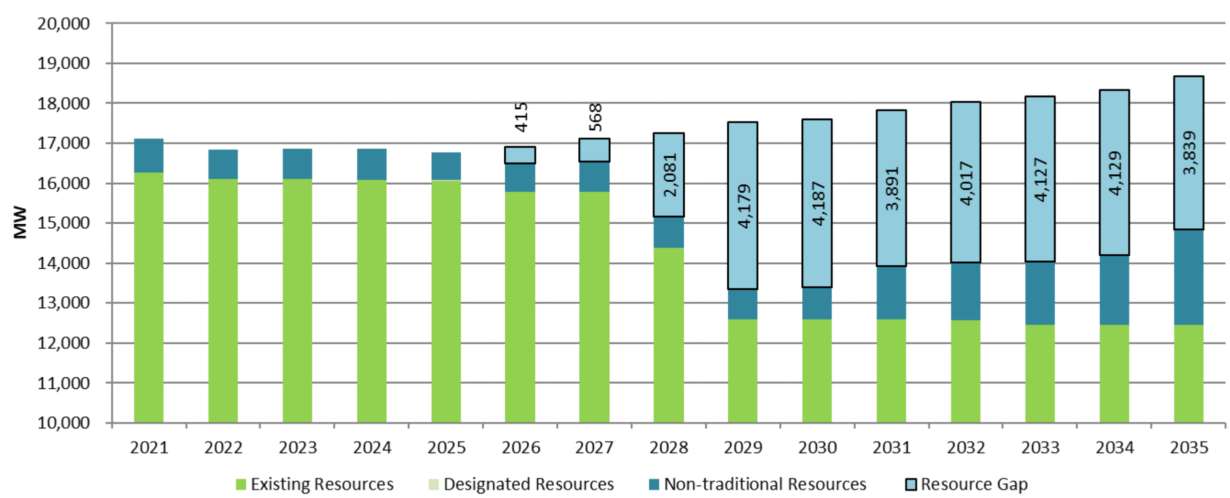


Figure 2. DEP Base Case with Carbon Policy Load Resource Balance (Winter)



- 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

[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: o Diversifying and expanding Duke's DSM resource mix o Expanding the DSM market and value proposition o Leveraging Duke's emerging data and rate infrastructure o Expanding both winter and summer demand response (DR) capacity o Reducing the need to purchase expensive wholesale power during peak o Avoiding or deferring capacity investments o 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: o Currently served on a flat volumetric rate who may be interested in the cost benefits that can be delivered by a TOU rate. o 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. o Who choose to participate in a technology-based load-shifting program and wish to increase their associated cost savings. o 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: o Have a standard AMI meter in place. (Duke may install and certify an eligible meter upon customer request to participate.) o Are currently enrolled for service under a flat volumetric or existing TOU rate. o 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: 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.
Energy Impacts and Winter Peak Demand Savings	– The total impact modeled by the Tierra Team under three scenarios indicated the following MW reduction impacts during winter peak. The estimated impact rises from a range of 2.2 to 3.3 MW in 2022 to a range of 61.2 to 81.7 MW by 2030.

2.1.1 Description

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

2.1.2 Objectives

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

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

2.1.3 Program Intersection with Winter Peak Needs and IRP Filings

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

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

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

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

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

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

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

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

2.1.4 Customer Eligibility / Targets

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

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

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

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

2.1.5 Rate Design

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

TOU Rate Considerations

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

2.1.6 Required Changes to Tariffs or Rates

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

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

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

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

2.1.7 Implementation and Operation

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

2.1.8 Market Potential and Participation Goals

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

Table 2.TOU Adoption Rates by Modeling Scenario

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

2.1.9 Marketing Plan

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

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

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

2.1.10 Measurement & Verification Plan

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

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

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

2.1.11 Energy Impacts and Winter Peak Demand Savings

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

2.2 Critical Peak Pricing ('CPP')

Table 3. CPP Program At-a-Glance

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

2.2.1 Description

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

2.2.2 Objectives

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

The objectives for implementing this program include:

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

2.2.3 Program Intersection with Winter Peak Needs and IRP Filings

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

[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.

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[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.

[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

[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: ○ 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. ○ 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: ○ A three-year commitment to share battery data and dispatch on-peak only ○ Continuous connection to Duke's DER aggregation platform and commitment to share operational data ○ Requirement to enroll in a qualifying time differentiated rate plan ○ 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: ○ A one-year commitment to participate in the DR program ○ Continuous connection to Duke's DER aggregation platform ○ 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

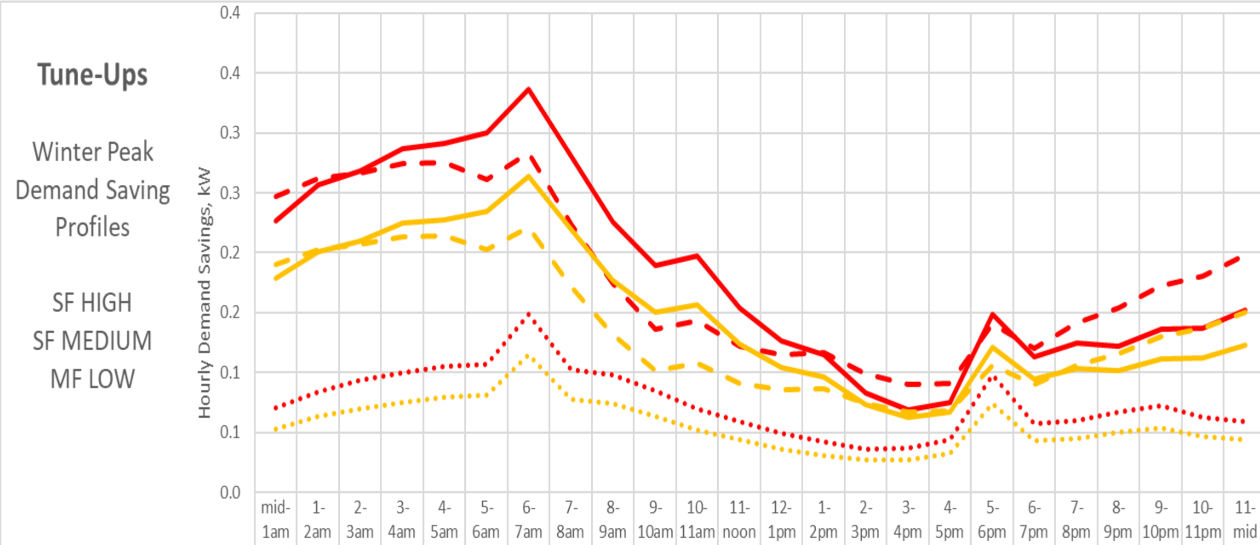
3.4.12 Energy Impacts and Winter Peak Demand Savings

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]

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

Figure 4. Modelled Electric Water Heater Load Profiles

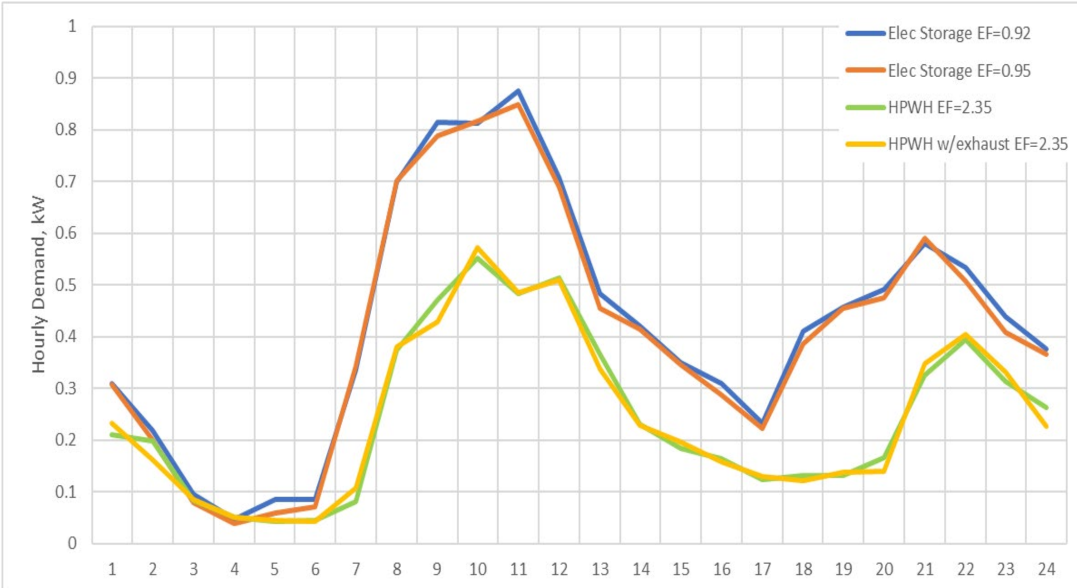


Figure 5 and Figure 6 illustrate the average daily hot water use for a 3-bedroom, 2 bath single family residence, including effects on space heating, during a 3-hour water heating control load shifting event. These figures show that water heaters typically operate in maintenance heat mode (i.e., prior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

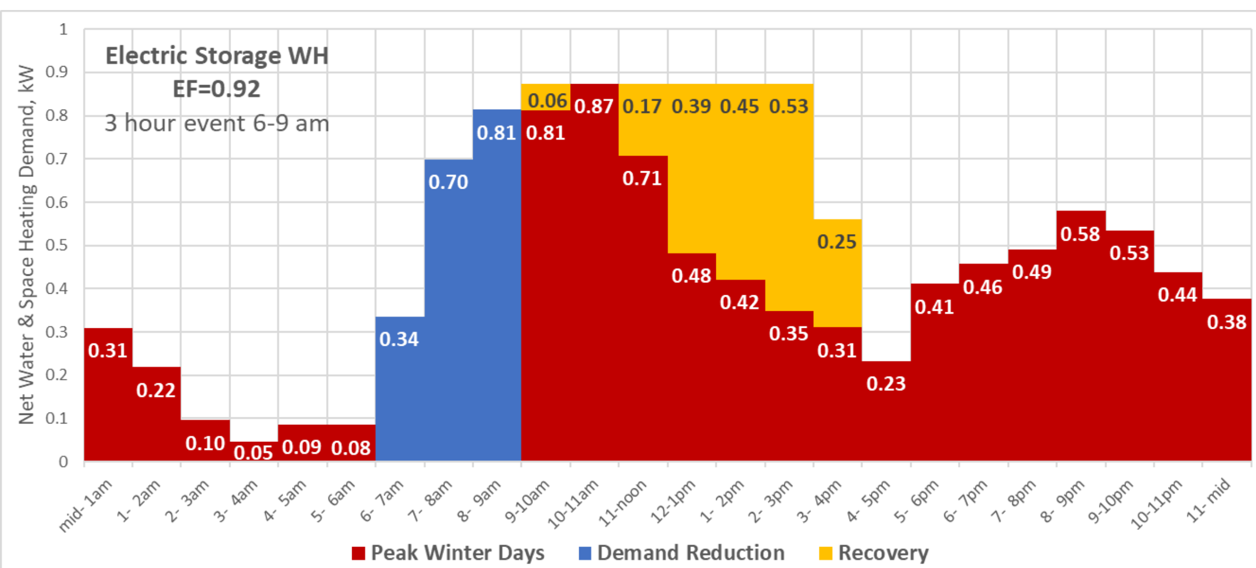
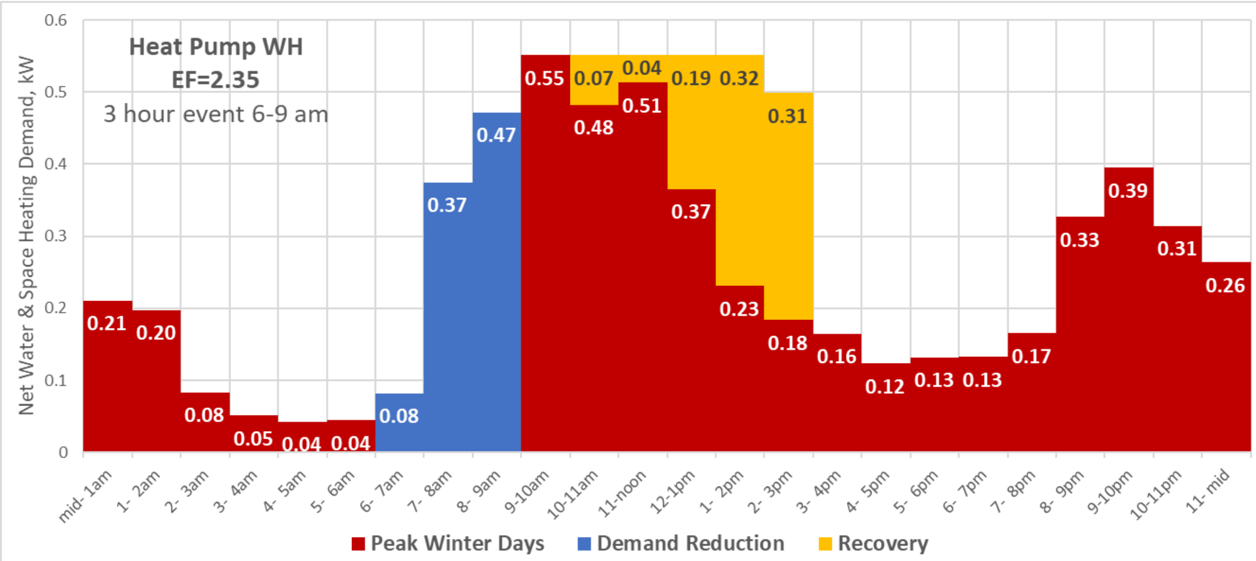


Figure 6. Modelled Heat Pump Water Heater Peak Load Shed Profile



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: o **Fleet Charging.** Duke commercial and industrial customers with vehicle fleets that have a duty-cycle which permits Duke managed off-peak charging. o **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. o 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: o Profile the market to help refine estimates of system interaction. This would include tracking development of load impacts from medium and large commercial trucks. o Identify third-party service providers for which pilot projects can be developed. o Define economic benefits that help drive commercial adoption. o 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.

[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

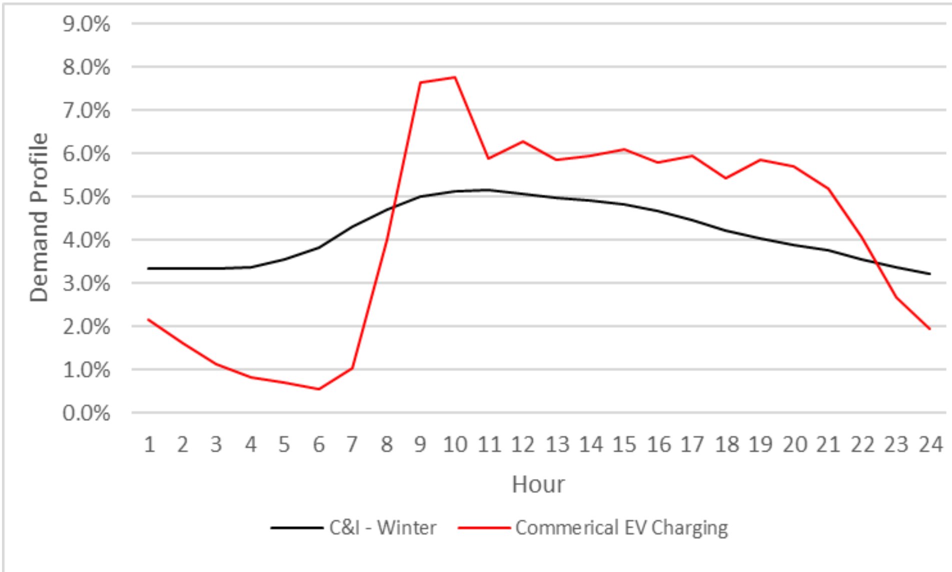
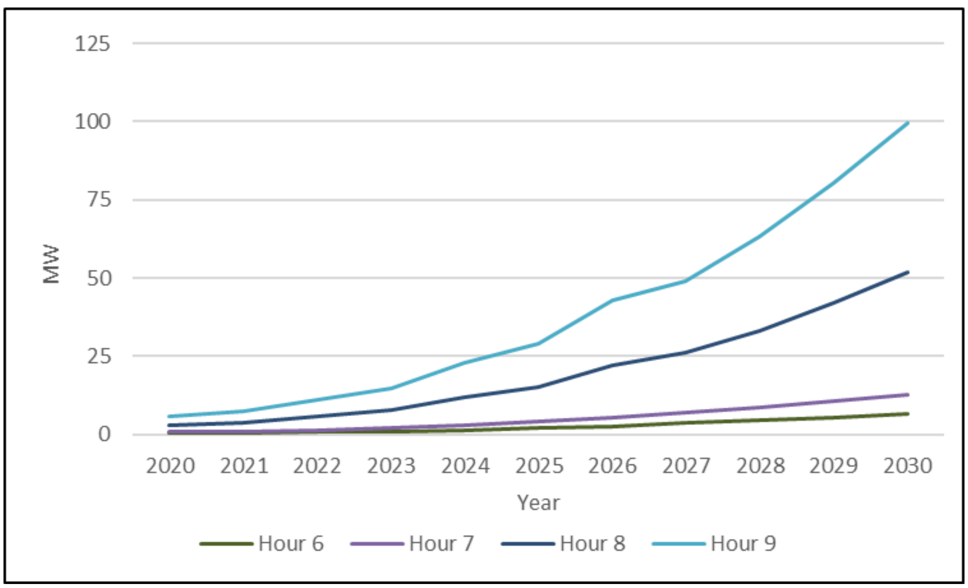


Figure 8. EV Charging Load Forecast by Morning Hour



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.

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

Review and Evaluation of the 2020 Resource Adequacy Studies Relied Upon for the Duke Energy Carolinas and Duke Energy Progress 2020 Integrated Resource Plans

James F. Wilson, Wilson Energy Economics

Prepared on behalf of Natural Resources Defense Council, Southern Alliance for Clean Energy, Sierra Club, South Carolina Coastal Conservation League, and Upstate Forever

February 5, 2021

Contents

I. INTRODUCTION AND SCOPE OF THIS REPORT

1. Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Companies" or "Duke") filed their 2020 Integrated Resource Plans ("2020 IRPs," "2020 Plans") on September 1, 2020 in North Carolina Utilities Commission Docket No. E-100, Sub 165 and Public Service Commission of South Carolina Docket Nos. 2019-224-E and 2019-225-E. The 2020 IRPs present load forecasts (Chapter 3 and Appendix C) and resource adequacy analysis and recommended reserve margins (Chapter 9 and Attachment III) that serve as the basis for each utility's determination of the total generating capacity required over the IRP planning horizon.

2. The resource adequacy analysis and reserve margins for the 2020 Plans were based upon resource adequacy studies ("DEC RA Study," "DEP RA Study"; collectively "RA Studies") prepared for DEC and DEP by Astrapé Consulting.[1] The analysis included in such RA Studies typically also serves as the basis for calculations of the capacity values of solar and other resources; however, a new solar capacity value study was not performed for the 2020 Plans (the Companies relied on their 2018 Solar Capacity Value Study).[2] The 2020 Plans attach a study of the capacity value of storage resources[3] that utilized the same model and the same load and resource assumptions as the 2020 RA Studies.[4]

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[1] Astrapé Consulting, *Duke Energy Carolinas 2020 Resource Adequacy Study*, Prepared for Duke Energy, September 1, 2020, DEC 2020 Plan Attachment III, and Astrapé Consulting, *Duke Energy Progress 2020 Resource Adequacy Study,* Prepared for Duke Energy, September 1, 2020, DEP 2020 Plan Attachment III.

[2] Duke Energy Response to Data Request NCSEA 3-8.

[3] Astrapé Consulting, *Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study,* Attachment III to the 2020 Plans, September 1, 2020 ("Storage ELCC Study").

[4] Storage ELCC Study p. 19.

3. In December 2020, the Companies released a Winter Peak Study[5] that identifies the customers and end uses contributing to winter peak loads and evaluates demand-side management programs to mitigate winter peak loads.

4. I reviewed and evaluated the previous (2016) DEC and DEP RA Studies in reports filed in 2019 and 2017,[6] raising a number of issues with the studies' assumptions and methodologies. I also reviewed the Companies' load forecasts, and discussed extreme winter peak load issues, in reports filed in the same dockets.[7]

5. This report reviews and evaluates the 2020 RA Studies relied upon for the 2020 Plans. I also reviewed and evaluated the Companies' peak load forecasts, however, I comment only briefly on those forecasts. My critique of the assumptions used in the RA Studies is equally applicable to the Storage ELCC Study which relies upon the same assumptions; however, an evaluation of the Storage ELCC Study is beyond the scope of this report. This report notes some aspects of

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[5] Tierra Resource Consultants, Dunsky Energy Consulting, and Proctor Engineering Group, *Duke Energy Winter Peak Analysis and Solution Set, Duke Energy Winter Peak Demand Reduction Potential Assessment,* and *Duke Energy Winter Peak Targeted DSM Plan*, December 2020 (Winter Peak Study Task 1, Task 2 and Task 3 Report, respectively, and collectively "Winter Peak Study").

[6] Wilson, James F., *Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing*, filed February 12, 2019 as Attachment 4 to Initial Comments of the Southern Alliance for Clean Energy in North Carolina Utilities Commission Docket No. E-100, Sub 157, also filed September 11, 2019 as Exhibit B to Direct Testimony on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy in South Carolina Public Service Commission Docket Nos. 2019-185-E and 2019-186-E ("Wilson 2019 RA Report"); Wilson, James F., *Review and Evaluation of the Reserve Margin Determinations for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans*, Attachment B to the Comments of Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club, filed February 7, 2017 in North Carolina Utilities Commission Docket No. E-100, Sub 147 ("Wilson 2017 RA Report").

[7] Wilson, James F., *Review and Evaluation of the Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans*, filed February 12, 2019 as Attachment 3 to Initial Comments of the Southern Alliance for Clean Energy in North Carolina Utilities Commission Docket No. E-100 Sub 157 ("Wilson 2019 Load Forecast Report"); Wilson, James F., *Review and Evaluation of the Peak Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans*, filed February 7, 2017 as Attachment A to the Comments of Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club, in North Carolina Utilities Commission Docket No. E-100 Sub 147 ("Wilson 2017 Load Forecast Report").

the scope and content of the Winter Peak Study as they pertain to the topic of resource adequacy, but an evaluation of that work is also beyond the scope of this report.

II. SUMMARY AND RECOMMENDATIONS

6. The RA Studies document probabilistic simulations of load and resources to find the planning reserve margin required to satisfy a "one day in ten years" ("1-in-10") resource adequacy criterion, equivalent to an annual Loss of Load Expectation ("LOLE") of 0.1 events per year.[8] The RA Studies identify a 16% winter planning reserve margin for DEC and 19.25% for DEP, based on separate analysis, and 16.75% for a "combined" case, ultimately recommending 17% for each utility (DEC RA Study pp. 17-18, DEP RA Study pp. 17-18). Both 2020 Plans adopt the recommended 17% planning reserve margin (DEC 2020 Plan pp. 66-67, DEP 2020 Plan pp. 68-69) driven by winter capacity needs, based on the recommendations of the 2020 RA Studies. The 17% winter planning reserve margin ensures at least a 15% summer planning reserve margin for both DEC and DEP.[9]

7. The Winter Peak Study adopted January 5, 2018, the recent day with the Companies' highest winter peak, as the "Study Peak Day,"[10] and the three-volume, 240-page study appears to be detailed and thorough with regard to demand response programs to address the loads that are expected to occur on the Study Peak Day. However, the RA Studies model winter peak loads over 13%, and over 4,400 MW, in excess of the highest load on the Study Peak Day,[11] and these extreme loads drive the RA Study results. The extreme loads represented

[8] For the purposes of the RA Studies, "The one day in 10-year standard (LOLE of 0.1) is interpreted as one day with one or more hours of firm load shed every 10 years due to a shortage of generating capacity." DEC RA Study p. 3.

[9] DEC RA Study p. 18, DEP RA Study p. 18.

[10] Winter Peak Study Task 1 Report p. 9.

[11] Duke Energy Response to Data Request SELC 5-1.

in the RA Studies are based on a simple arithmetic extrapolation, as this report will discuss; they not based on any analysis or theory of how loads greater than the Study Peak Day could occur (what customers or end uses). Nor did the Winter Peak Study discuss the possibility of winter peak loads higher than the Study Peak Day, evaluate what customers and end uses could contribute to loads higher than the Study Peak Day, or identify or evaluate programs tailored to mitigating loads greater than the Study Peak Day.

8. Based on the Winter Peak Study's scope (focusing on the customers and end uses that make up the Study Peak Day, and programs to reduce these loads) it appears that, contrary to the RA Studies, the Companies assign low likelihood to, and are not particularly concerned about, the possibility of winter peak loads substantially in excess of the Study Peak Day. If instead the Companies believe such extreme loads beyond the Study Peak Day are reasonably likely to occur (as assumed in the RA Studies), *how* such loads can occur (what customers and end uses cause them), and approaches to mitigating them, should have been major topics of the Winter Peak Study.

9. In addition, the RA Studies assigns relatively high likelihood to very extreme temperatures that have not been seen in the Carolinas, or only rarely, in past decades, and these very extreme conditions drive the RA Studies' results. The Winter Peak Study does not explicitly consider such extreme conditions or evaluate programs specifically designed to reduce loads under such conditions (such as inducements for facilities to open late or remain closed).

10. Accordingly, the Winter Peak Study and the RA Studies are highly inconsistent and contradictory – the RA Studies recommend a reserve margin driven by extreme conditions and extreme winter loads well in excess of the Study Peak Day, while the Winter Peak Study does not even acknowledge such conditions and loads are possible.

11. As I will explain in detail in this report, the extreme winter loads in the RA Studies result from a flawed extrapolation approach for associating loads

to extremely low temperatures that have not been seen for decades. In my 2019 Load Forecast Report, I recommended that the Companies develop a more sophisticated model of how extreme winter weather affects their loads.[12] This important work was not pursued.

12. The main conclusion of this report is that the RA Studies have substantially overstated winter resource adequacy risk. The winter resource adequacy risk was overstated largely due to the following flaws in the RA Studies' analyses:

a. The primary flaw is the inaccurate approach to estimating the impact of extreme cold on loads, extrapolating based on observations at milder temperatures.

b. In addition, the RA Studies used 39 years of temperature data (1980-2018), weighted equally, which includes many instances of very extreme cold that have not been seen in these areas, or only rarely, for decades. This overstates the likely frequency of such extreme cold going forward, therefore amplifying the effect of overstating the impact of extreme cold on winter peak loads.

c. Power plant forced outage rates under extreme cold have also been overstated.

13. While a number of other assumptions adopted in the RA Studies that impact the physical reliability results appear very conservative and could be questioned (such as, external region and market diversity and potential assistance, and demand response operational limits), this report focuses on the issues identified in the previous paragraph.

14. Overstating loads under extreme cold conditions had a substantial impact on the RA Studies' results and recommendations. Through discovery, the Companies provided data showing the specific scenarios within the RA Studies'

[12] Wilson 2019 Load Forecast Report p. 21.

simulations that led to lost load.[13] The majority of the winter hours with loss of load are from scenarios under which the DEC load was 106% of the value on the Winter Peak Study's Study Peak Day or higher. Fully 94% of the loss of load in the DEC RA Study occurs on days with loads in excess of the Study Peak Day value. In the DEP RA Study, the majority of the load loss is in hours with load 114% of the Study Peak Day peak load or higher. 99% of the loss of load in the DEP RA Study occurs under loads in excess of the Study Peak Day value.

15. In my 2019 RA Report I recommended that the Companies "research the drivers of sharp winter load spikes under extreme cold conditions" and "study the relationship between extreme cold conditions and load, taking into account other relevant factors such as likely facility closures and the impact of wind speeds, to inform future resource adequacy studies."[14] While the Winter Peak Study states that it was "initially pursued because of input from stakeholders . . ."[15] there is no evidence such research took place, or that the Companies have gained a better understanding of the relationship between extreme cold conditions and load. As I will explain in this report, the Companies and Astrapé use different and highly simplified approaches to this key question. To the extent the Winter Peak Study reflects such research, apparently the authors felt that under the most extreme conditions loads would not increase very much beyond the Study Peak Day level, due to factors such as the full deployment of space heating equipment and facility closures.

16. In my 2019 RA Report I had also recommended that the Companies "develop programs for shaving these rare and brief spikes" that occur under the most extreme cold. In my 2019 Load Forecast Report I recommended that the

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[13] Duke Energy Response to Data Request ORS AIR 2-35(k), which identifies the particular scenarios that lead to load loss. Note that this data was provided for reserve margins near, but not equal to the recommended reserve margins. See Duke Energy Response to Data Request SELC 6-2.

[14] Wilson 2019 RA Report p. 24.

[15] Winter Peak Study Task 3 Report p. 15.

Companies prepare a tailored plan to engage customers in mitigating extreme peak loads, to be activated if needed when extreme winter weather approaches.[16] Again, apparently the Companies, and the authors of the Winter Peak Study, do not actually anticipate loads much beyond the Study Peak Day with any frequency, for there is no evidence of plans to mitigate such loads.

17. Due to the overstatement of winter resource adequacy risk, I again conclude that the recommended DEC and DEP planning reserve margins are unsupported and higher than necessary. If the flaws I have identified were even partially corrected, the 14.5% summer planning reserve margin that was in place until the 2016 IRP, which would provide a 16.5% winter reserve margin, would be more than adequate.

18. Due to the identified flaws in the RA Studies' assumptions, I also recommend that the analysis and assumptions reflected in the 2020 RA Studies be rejected as the basis of the Storage ELCC Study, or of any future studies of the capacity value of solar or other resource types.

19. This report also comments on two other aspects of the RA Studies:

a. While the RA Studies' recommendations are based on physical reliability results, the reports also present economic reliability calculations. These calculations rest upon numerous highly questionable assumptions, and no weight should be assigned to them. To the extent any attention is given to these calculations, the focus should be on "risk neutral" values, rather than values that assume customers should pay more on average over the long run for additional capacity in order to potentially reduce infrequent high-cost outcomes.

b. The RA Studies also included assumptions about multi-year load forecasting errors ("economic load forecast error"). As in my

[16] Wilson 2019 Load Forecast Report p. 22.

previous reports, I again conclude that it is inappropriate to use multi-year load forecast uncertainty in a model that cannot represent short lead-time adjustments to unexpected load growth, and I again question whether historical Congressional Budget Office Gross Domestic Product forecasting errors are a reasonable basis for estimating the Companies' peak electric load forecasting errors.

20. I also reviewed the Companies' peak load forecasts and the underlying data and assumptions. Based on the information available at the time they were prepared, the load forecasts appear to fall within a reasonable range. However, these forecasts were prepared based on pre-pandemic economic projections (from January 2020), so "the potential impacts of COVID-19 are not incorporated in this forecast."[17] Economic forecasts have generally been lowered since January 2020, so peak loads in the coming years are likely to be somewhat lower than reflected in the Companies' forecasts.

21. The remainder of this report is organized as follows. Section III discusses the issues with the 2020 RA Studies that lead to overstating winter resource adequacy risk. Section IV discusses other concerns about the RA Studies. Section V provides a summary and recommendations for future IRPs. Appendix A summarizes the author's qualifications.

[17] DEC 2020 Plan p. 8.

III. THE RA STUDIES OVERSTATE WINTER RESOURCE ADEQUACY RISK

22. This section first explains that the RA Studies substantially overstate winter extreme peak loads due to a flawed extrapolation approach for estimating how loads would increase due to extreme temperatures. The second subsection reviews the temperature data, concluding that the impact of the flawed extrapolation was amplified by a data set that includes many instances of temperatures that have not been seen in decades and whose likely future frequency of occurring is therefore overstated. The third subsection explains that the frequency of cold-related forced outages was also overstated. These flaws drove the winter resource adequacy risk and reserve margins higher than they would otherwise be.

23. Nearly all of the resource adequacy risk in the 2020 RA Studies is in winter, and nearly all of the risk is in winter mornings, not evenings.[18] Because winter mornings drive the results, this report generally focuses on winter mornings.

A. THE IMPACT OF EXTREME COLD ON WINTER PEAK LOADS IS OVERSTATED

24. In the winters of 2014, 2015, and 2018 there were instances of very low winter temperatures in the DEC and DEP-East[19] service territories. Based on the temperature data used for the DEC RA Study,[20] 2014 and 2015 each had two days in which temperatures dropped below 10 degrees Fahrenheit. However, the 2020 RA Studies used 39 years of historical weather data, back to 1980, and far

[18] Duke Energy Response to Data Request ORS AIR 2-35(k). In DEC, 96% of the LOLE is winter mornings, and the remainder is in summer. In DEP, 99% of the LOLE is winter mornings, the remainder is winter evenings.

[19] Some of the data in the RA Study workpapers distinguishes the eastern and (much smaller) western portions of the DEP service territory separately. As appropriate, this report will refer to DEP-East and DEP-West for the two portions. See DEC 2020 Plan p. 30 for a map of the service territories.

[20] RA Study support file "All Region Temps 1980-2018." The temperatures associated with each service territory are weighted averages of temperatures at multiple weather stations. See Duke Energy Response to Data Request NC Public Staff data request 1-1(g), attachment "PS DR 1 - Load Forecast - Part G.docx."

lower temperatures were seen in some years in the 1980s (in the DEC service territory, minus 5 degrees in 1985, and 3, 4, and 5 degrees in 1982, 1983, and 1986, respectively). The DEC 39-year data set includes 109 hours with temperatures below 9 degrees, but only 8 of these hours occurred since 1996; the DEP-East 39-year data set includes 67 hours with temperatures below 10 degrees, but this has only occurred once since 1996. Therefore, to use the 39 years of weather data to develop the synthetic load shapes for the RA Study simulations, Astrapé had to model loads under temperatures that have not occurred, or only rarely, in recent decades.

25. The RA Studies generally associated loads with temperatures using a neural network approach.[21] However, for the most extreme temperatures (high or low) for which there are fewer observations, the neural network approach was considered inaccurate, so an additional step, based on regressions, was used to "extrapolate the peaks."[22] The approach entailed estimating the amount by which incremental cold apparently increased load in the 10 to 21 degree range through regression.[23] The results of the regressions, expressed in MW/degree, were then used to extrapolate load levels to the very low temperatures found in the 39-year history. As discussed further below, the extreme loads resulting from these regressions account for nearly all of the load loss in the simulations, and drove the reserve margins higher than they would otherwise be.

26. There are three problems with this extrapolation approach that result in substantially overstating loads under extreme cold. These three flaws are discussed in the following subsections.

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[21] DEC RA Study p. 23. Under the neural network approach, algorithms are employed that endeavor to recognize the underlying relationships in a set of data (in this instance, the relationship of load to temperature) through a process that mimics the way the human brain operates.

[22] Duke Energy Response to Data Request NCSEA 3-3.

[23] Duke Energy Response to Data Request SELC 3-9.

i. THE EXTRAPOLATION APPROACH IS CONCEPTUALLY FLAWED: THE INCREMENTAL IMPACT OF EXTREME COLD DECLINES AT THE LOWEST TEMPERATURES.

27. First, this extrapolation approach assumes that when temperatures drop to extremely low temperatures (15, 10, 5 degrees and even lower), each additional degree will increase loads by the same amount as occurs at around 20 degrees. But for the lowest temperatures, the relationship between temperature and load is much weaker. This is logical -- once temperatures drop to the teens, customers are likely already operating space heating equipment at maximum levels; if temperatures fall even lower, few customers have additional equipment they can turn on. In addition, the winter peak loads under extreme temperatures typically occur in the 7 to 9 AM time frame;[24] under the very rare extreme cold conditions, some schools, offices, and other commercial, government and industrial facilities may open late, remain closed, or operate at reduced levels, reducing loads during the early morning peak on such days. Thus, extrapolating based on temperature-load relationships in the 10 to 20 degree range is conceptually flawed, and not a sound way to estimate what loads would be under the most extreme temperatures for which there is little or no recent data.

ii. THE REGRESSIONS, BASED ON OBSERVATIONS UP TO 21 DEGREES, OVERSTATE THE IMPACT OF INCREMENTAL COLD ON LOAD AT THE LOWEST TEMPERATURES.

28. The second flaw is in the regression approach itself, which led to overstated estimates of the impact of incremental cold even for the 10 to 15 degree range. The regressions estimate how much load increases for each degree the temperature falls, based on the chosen set of historical observations. The RA Studies used daily minimum temperatures for the regressions, and included observations up to 21 degrees from recent years.[25] Most of the observations

[24] Winter Peak Study Task 1 Report p. 9.

[25] Duke Energy Response to Data Request SELC 3-9 attachment.

reflected in the regressions were in the 18 to 21 degree range for DEC, and in the 16 to 21 degree range for DEP-East. Based on these regressions, the RA Studies estimated the impacts of extreme cold on loads as shown in Table 1.

Table 1: RA Study Assumed Impact of Extreme Cold on Load[1]

	Winter Mornings		Winter Evenings	
	MW/degree	Percent/degree	MW/degree	Percent/degree
DEC	216.6	1.2%	120.3	0.7%
DEP-E	263.2	1.9%	243.8	2.0%
DEP-W	13.2	1.1%	14.3	1.3%
Total	493.0		278.3	

[1] Duke Energy Response to Data Request SELC 3-9 attachment. Estimates based on regression of daily peak loads to daily morning/evening minimum temperatures, for temperatures 21 degrees and below, first averaging loads in one-degree increments.

29. The value for winter mornings in the DEC service territory, 216.6 MW/degree, implies that for each additional degree the temperature falls, DEC's load is assumed to increase by 216.6 MW (roughly 1.2%). Ten additional degrees would increase loads by 2,166 MW, well over 10% of the peak load. Similarly, the extrapolation approach suggests that the DEP-East loads would increase 263.2 MW for each additional degree the temperature drops.

30. As noted earlier, in prior IRP dockets I have recommended research to develop a more sophisticated approach to estimating the impact of extreme weather on loads,[26] and this research has not occurred. Instead, the Companies and Astrapé continue to use various simple approaches for this very important relationship that drives RA Study results. For the 2016 RA Studies, Astrapé used the actual temperature in the hour of the peak load for such regressions, not morning minimums, and did not perform the averaging in one-degree

[26] Wilson 2019 Load Forecast Report p. 21.

increments.[27] Yet another very flawed approach to estimating the impact of extreme cold on loads, using "Peak Load Adjustment Factors,"[28] was recently applied in a resource adequacy study for Southern Company, on which Astrapé's role was to provide technical modeling guidance and confirm the technical accuracy of the inputs and methods.[29] The Companies use still another approach to estimating the impact of extreme weather on peak loads, based on very different regressions, to estimate historical weather-normal peaks.[30]

31. The 2020 RA Studies employed a simplistic and flawed way to estimate the impact of incremental cold on loads. First, daily minimum temperatures during morning hours were used to represent winter morning cold conditions. While this may be a reasonable measure for some days, it is a poor measure for other days, for instance on days when the minimum occurs several hours before or after the peak load.

32. However, the more important flaw in the regression approach was to include observations for temperatures up to 21 degrees. The same regression analysis, but excluding the higher temperatures, provides a more reasonable estimate of the impact of incremental cold on load at lower temperatures (although, again, using this estimate to extrapolate to very low temperatures is conceptually flawed and invalid). As I will show next, and also showed in my 2019 and 2017 RA reports, the impact is far lower when the analysis properly focuses on lower temperatures.[31]

33. I performed the same regressions, but excluded the observations at higher temperatures. The results are shown in Figures JFW-1 and JFW-2.

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[27] Duke Energy Response to Data Request SACE/NRDC/Sierra Club 3-1 attachment in Docket E-100, Sub 157.

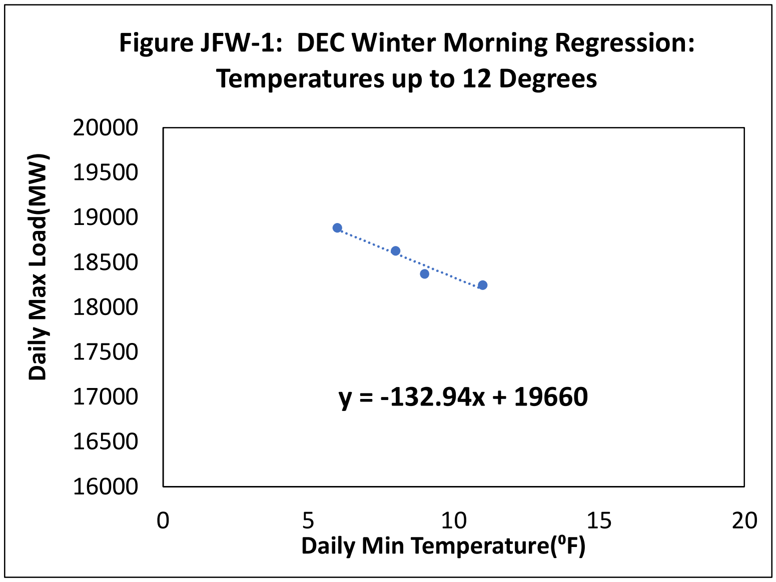
[28] See *Direct Testimony of James F. Wilson on Behalf of Energy Alabama and GASP*, pp. 48-55, filed December 4, 2019 in Alabama Public Service Commission Docket No. 32953.

[29] See *Rebuttal Testimony of Kevin D. Carden on Behalf of Alabama Power Company*, p. 3, filed January 27, 2020 in Alabama Public Service Commission Docket No. 32953.

[30] Duke Energy Response to Data Request SELC 2-18.

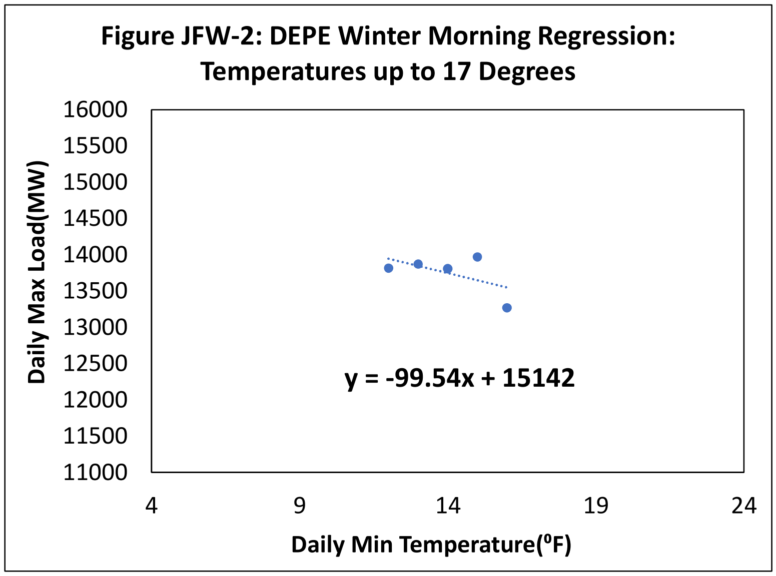
[31] Wilson 2019 RA Report pp. 8-10, Wilson 2017 RA Report pp. 6-8.

34. For DEC, across the entire temperature range up to 21 degrees, the relationship was 216.6 MW per degree, as shown in Table 1, above. When the regression is focused on temperatures 12 degrees and lower, the impact of cold is just 133 MW/degree. While the observations are few, they do fall in line quite well, as shown in Figure JFW-1.



35. For DEP-East, the observations used for the regression have less cluster, with outliers at the coldest and also at more moderate temperatures. Just dropping the single observation in the 10-11 degree range changes the estimate from 263.2 MW/degree to 220.2 MW/degree; and additionally focusing the analysis on temperatures below 17 degrees further lowers the estimate to 99.5 MW/degree, as shown in Figure JFW-2. If the most moderate observation, at 16 degrees, is also dropped, the regression suggests further cold does not increase load at all.

36. While dropping the outlier in the 10-11 degree range, or the more moderate observation at 16 degrees, may or may not be justified based on the particulars of these events, the high sensitivity of the regression results to these choices demonstrates the arbitrary nature of the regression approach.



37. Again, it is likely that even the lower MW/degree values from the calculations shown in Figures JFW-1 and JFW-2 overstate the additional impact of the most extreme temperatures on loads, because, as suggested above, at the lowest temperatures, space heating appliances are already in full use and some facilities will open late or remain closed.

iii. THE REGRESSION VALUES WERE APPLIED IN A MANNER THAT LEADS TO SOME EXTREME AND NONSENSICAL RESULTS.

38. The third flaw in the extrapolation approach was in the details of how the MW/degree results of the regressions were combined with the neural network results to determine the final loads used in the RA Studies. While the exact approach is not documented and rather opaque, the values in Table 1 were

generally applied for temperatures below 20 degrees.[32] Apparently the MW/degree values shown in Table 1 were applied to the number of degrees below 20, with the resulting MW value added to the neural network results.

39. The 39-year data set used in the DEC RA Study includes temperatures as low as minus 5 degrees for DEC (on January 25, 1985).[33] Estimating loads at minus 5 degrees based on the 216.6 MW/degree value shown in Table 1 resulted in loads as high as 21,993 MW. Using instead the 132.9 MW/degree estimate shown in Figure JFW-1, this load would drop by over 2,000 MW ((216.6 – 132.9) x (- 5 – 20)), to under 20,000 MW. All other assumed loads under the most extreme temperatures would also be much lower, using a more moderate estimate of the impact of temperature on load. Again, even if a reasonable estimate of the MW/degree value were prepared, it would very likely overstate loads for the lowest temperatures, because the extrapolation approach is conceptually flawed.

40. Temperatures down to minus 2 degrees are modeled for DEP-East, however, the DEP RA Study states that for this particular, most extreme temperature, the regression result was not fully applied.[34] For plus five degrees, the 263.2 MW/degree value would result in adding almost 4,000 MW (263.2 x (5 - 20)) to the load estimate based on the neural network approach. If instead the 99.5 MW/ degree value from Figure JFW-2, the adder is 2,500 MW lower. The choice to use temperatures as high as 21 degrees in the regressions led to the high MW/degree values shown in Table 1, and greatly increased the most extreme loads used in the DEP RA Study.

41. The application of the regressions can also lead to some nonsensical load values. I note two examples.[35]

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[32] Duke Energy Response to Data Request SELC 7-2.

[33] RA Study support file "All Region Temps 1980-2018."

[34] DEP RA Study p. 25 (stating that the load for the negative temperature value was capped).

[35] Duke Energy Response to Data Request SELC 5-1.

42. In the early morning of March 3, 1980 in DEP-East temperatures fell to the high teens. The RA Studies' synthetic load shapes have a peak load for March 3, 1980 at 3 AM, 14,597 MW, with a temperature of 18.9 degrees. This is a very high load; it is the twelfth largest daily peak load in the entire 39-year database for DEP-East, and loss of load occurs in this hour under some of the DEP RA Study scenarios.[36] Why would such a high load occur at 3 AM, and under a relatively mild temperature? The neural network approach suggested a load of only 10,526 MW, but the regression result was applied to override this value, adding over 4,000 MW based on the regression to get the 14,597 MW value. As the morning of March 3, 1980 continued, temperatures continued to fall to a minimum of 13.8 degrees at 8 AM, the hour when winter loads typically reach their peak. But the RA Study shows a much lower load, 12,256 MW, at 8 AM. A huge load peak at 3 AM with mild temperatures, and much lower loads at 8 AM under colder temperatures, makes no sense.

43. As another example, in the DEC service territory, on January 20, 1985 temperatures were falling through the day, and the RA Studies show the peak load at 5 PM, 18,046 MW, with a temperature of 14.7 degrees. This is the highest winter evening load in the database; in fact, the next highest is over 1,600 MW lower. This again reflects a large override of the neural network result; over 2,200 MW was added to this hour based on the regression, and as much as 3,100 MW was added to other hours of this day. These huge adjustments based on the regression apparently result from the fact that temperatures continued to fall to very low levels by midnight. This reflects the flawed approach of using morning and evening peak loads and *minimum* temperatures in the regressions; in those instances where the minimum temperature occurred hours after the peak, the minimum clearly did not drive the peak.

[36] Duke Energy Response to Data Request ORS AIR 2-35(k).

44. Figure JFW-3 and JFW-4 show figures from the 2020 RA Studies illustrating how high winter peaks are assumed to go, relative to the winter peak loads in a "normal" year, based on the most extreme weather in each of the 39 years for which weather data was used. These figures also show the corresponding figures from the 2016 RA Studies. I offer the following observations based on these two figures.

a. First, note that the values for 2018 (the year of the Winter Peak Study's Study Peak Day) are well above (about 5% above) the normal winter peak for both DEC and DEP. The Study Peak Day is indeed an unusually high winter peak load.
b. Second, note some substantial differences in these values between the 2020 and 2016 RA Studies, despite the fact that the common historical data has not changed. For DEC, 2014 and 2015 were 6% to 8% above normal in the 2016 RA Study, but in the 2020 RA Study these years are now considered over 10% above normal. In the 2016 RA Study 1982 was 18% above normal; in the 2020 RA Study it is now 11%. In the 2016 RA Study 1985 was 13% above normal; in the 2020 RA Study it is now 18%. These substantial changes in both directions again reflect the rather arbitrary nature of the extrapolation approach used to assign extreme loads to extreme temperatures. The DEP figures also reflect substantial changes, though not as extreme as for DEC.

Figure JFW-3: Figure 3 from 2020 and 2016 DEC RA Studies

Figure 3. DEC Winter Peak Weather Variability (2020)

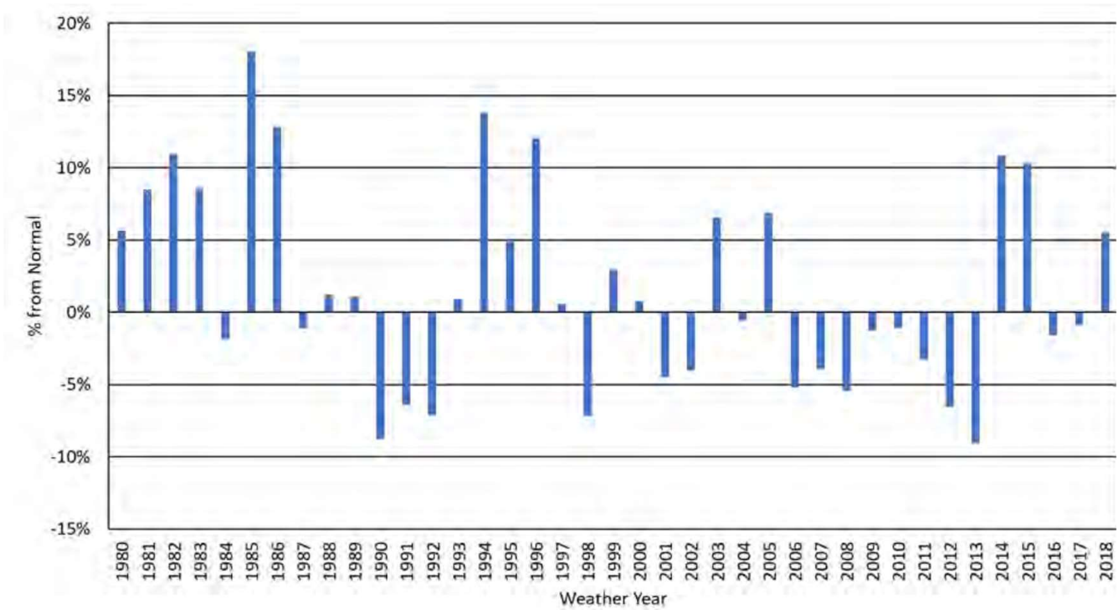

Figure 3. DEC Winter Peak Weather Variability (2016)

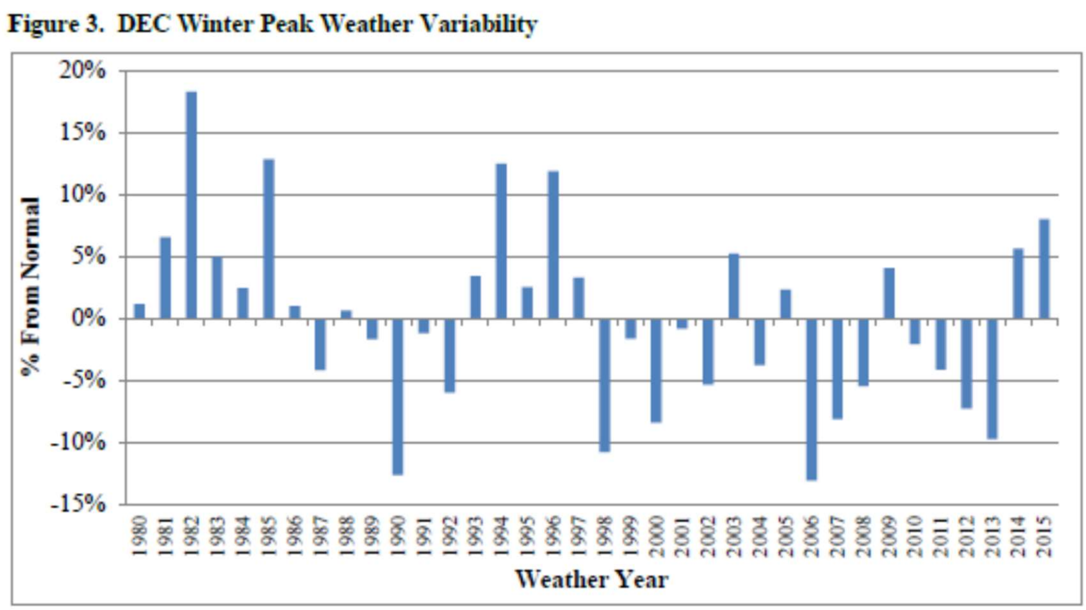

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Figure JFW-4: Figure 3 from 2020 and 2016 DEP RA Studies

Figure 3. DEP Winter Peak Weather Variability (2020)

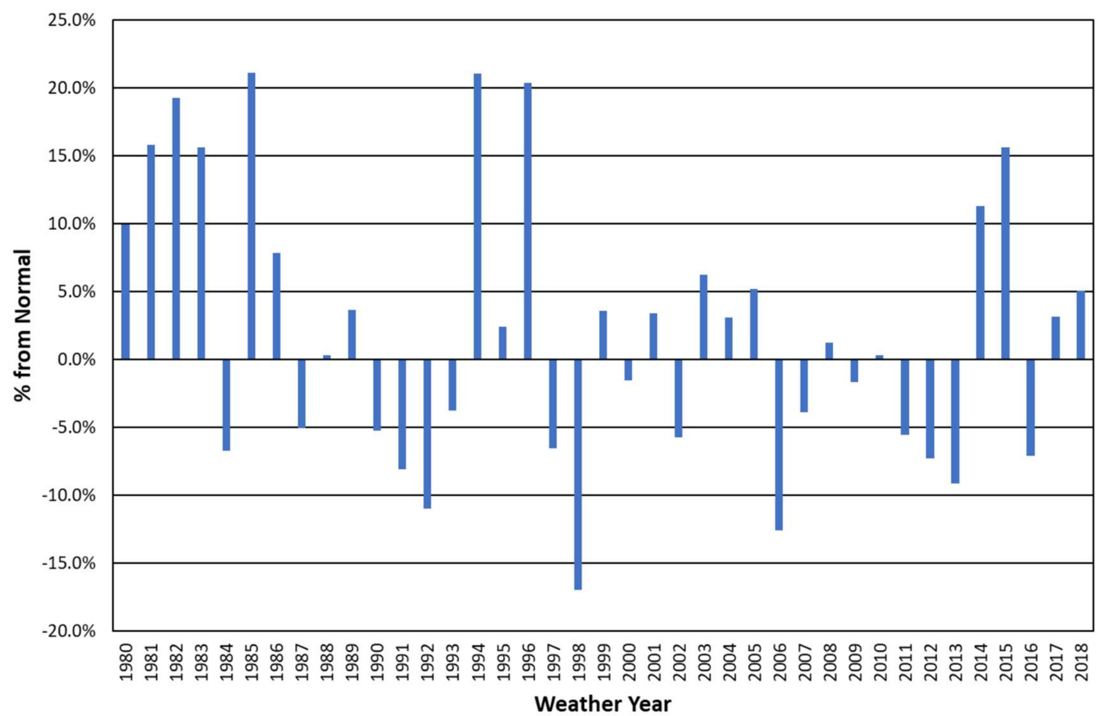
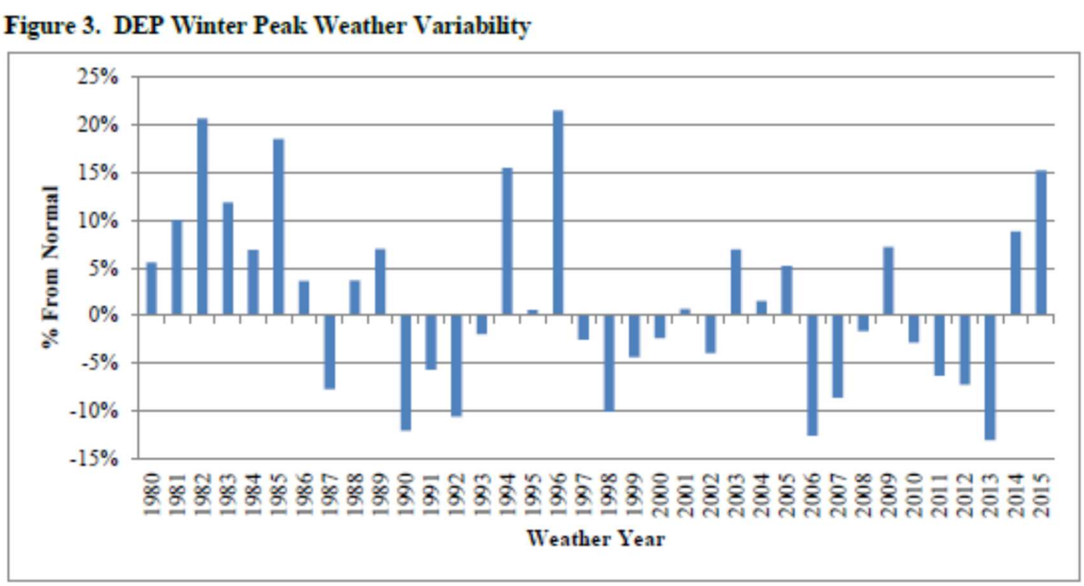


Figure 3. DEP Winter Peak Weather Variability (2016)



45. I conclude that the RA Studies greatly overstated loads under extreme cold conditions, due to the flawed extrapolation approach, as discussed

above.

46. Unfortunately, unlike in prior IRPs,[37] the RA Studies include no sensitivity analysis to the high winter load assumptions. However, these overstated loads had a substantial impact on RA Study results, as will be shown below.

B. THE LIKELY FREQUENCY OF THE MOST EXTREME COLD IS OVERSTATED

47. The 39 years of temperature data (1980-2018) used in the RA Studies included many instances of extreme cold that have not been seen, or only rarely, for decades. This calls into question how likely we should expect such extreme cold to be going forward, and whether the RA Studies have overstated the frequency of such extreme cold (all years are equally weighted) and resulting high loads. Overstating the likely future frequency of extreme cold amplifies the effect of overstating the impact of extreme cold on winter peak loads discussed in the prior section.

48. In particular, for the DEC region:[38]

a. The 39-year data set includes 109 hours with temperatures below 9 degrees. But 101 of these instances were in the first 17 years of the period (1980 to 1996), and temperatures below 9 degrees have occurred only 8 times since 1996 (the last 22 years of the data). Two-thirds of these hours occurred in the 1980s.

b. The full data set includes 63 hours with temperatures below 7 degrees. But this has only occurred once since 1996 and only 16 times since 1989.

[37] See, for instance, Wilson 2019 RA Report p. 13.

[38] Duke Energy Response to Data Request SELC 5-1.

c. The full data set includes 44 hours with temperatures under 6 degrees, down to -4.7 degrees. But temperatures below 6 degrees have not occurred since 1996 and only 7 times since 1989.

d. There are 15 hours below 3 degrees, all of which occurred in 1982 and 1985.

49. Similarly, for the DEP-East region:

a. The 39-year data set includes 105 hours with temperatures below 12 degrees. But 97 of these occurred in only the first 17 years of the period (1980 to 1996), and this has occurred only 8 times since 1996 (the last 22 years of the data). Over 70 percent of these hours occurred in the 1980s.

b. The full data set includes 67 hours with temperatures below 10 degrees. But this has only occurred once since 1996 and only 16 times since 1989.

c. The full data set includes 33 hours with temperatures under 8 degrees, down to -1.9 degrees. But temperatures below 8 degrees have not occurred since 1996 and only 6 times since 1989.

d. There are 11 hours below 5 degrees, all of which occurred in 1982 and 1985.

50. The most extreme temperatures, and the extreme loads assigned to them based on extrapolation, drive the results of the RA Studies. In the DEC RA Study simulation, 97% of the loss of load events in winter occur under scenarios with temperatures under 9 degrees. 76% of the winter loss of load occurs under scenarios with temperatures of 6.4 degrees or less, which has only occurred once since 1996. 69% of the loss of load is on scenarios with temperatures below 6 degrees, which has not occurred since 1996. Of the over 14,200 weather days represented in the RA Studies (based on 39 years), two – January 11, 1982 and January 21, 1985 – account for 43% of the LOLE in the DEC RA Study.

51. In the DEC RA Study, the majority of the winter hours with loss of load are from scenarios under which the winter extrapolated DEC load exceeded 20,000 MW, even before load forecast uncertainty was applied (which leads to even more extreme loads).[39] This is 106% of the DEC RA Study's value for the Winter Peak Study's Study Peak Day, January 5, 2018, which is 18,820.4 MW. Fully 94% of the loss of load in the DEC RA Study occurs on days with loads in excess of the Study Peak Day value.

52. In the DEP simulation, 97% of the winter loss of load is under scenarios with 11 degree or lower temperatures. 96% of the winter loss of load is under 10.1 degrees, which has only occurred once since 1996. 79% of the winter loss of load is at 8 degrees or less, which has not occurred since 1996.

53. On the DEP system, the majority of the load loss is on hours with load in excess of 17,480 MW before application of load forecast uncertainty. This is 114% of the value associated with the Study Peak Day. 99% of the loss of load in the DEP RA Study occurs under loads in excess of the Study Peak Day value.

54. Some of these observations are summarized in Table 2.

Table 2: Frequency and Impact of Extreme Temperatures in RA Studies[1]

	Temperature threshold	# days with such temperatures		% of RA Study LOLE under such temperatures
		RA Studies (1980-2018)	Since 1996	
DEC	< 9 degrees	109	8	97%
DEP-E	< 12 degrees	105	8	97%

[1] Duke Energy Responses to Data Requests SELC 5-1 and ORS AIR 2-35(k).

55. As noted above, the RA Studies provided no sensitivity analysis that shows the impact of the assumed extremely high loads assigned to extremely low temperatures on RA Study results. However, Astrapé did perform a sensitivity

[39] Duke Energy Response to Data Request ORS AIR 2-35(k).

analysis under which the 29 years of temperature data from 1990 to 2018 was used (the data from the 1980s was dropped), while no other changes were made. Using data from 1990 to 2018 rather than 1980 to 2018 had a huge impact on the reserve margins to meet the 1-in-10 standard: 13.25% for DEC and 14.75% for DEP, compared to 16% and 19.25%, respectively, from the RA Studies.[40] Note that this is only due to dropping the 1980s temperature data; these reserve margins still reflect application of the flawed extrapolations that overstate the impact of extreme cold on load.

56. To summarize, the vast majority of the winter load loss in the 2020 RA Studies is based on a highly simplified and inaccurate assumption about how loads would increase under the most extreme temperatures, applied to temperatures that have not been seen, or only very rarely, in decades, and whose frequency of occurring is overstated. These assumptions drove the winter risk and reserve margins higher.

C. Winter Forced Outage Rates Under Extreme Cold Are Overstated

57. The RA Studies also exaggerated winter resource adequacy risk by including 400 MW of additional forced outages under all scenarios under 10 degrees:[41]

> "The 2014-2019 period showed more events than the 2016-2019 period which is logical because Duke Energy has put practices in place to enhance reliability during these periods, however the 2016 – 2019 data shows some events still occur. The average capacity offline below 10 degrees for DEC and DEP combined was 400 MW. Astrapé split this value by peak load ratio and included 260 MW in the DEC Study and 140 MW in the DEP Study at temperatures below 10 degrees."

[40] Duke Energy Response to Data Request SELC 3-4 (referring to the file "AG Office Follow-up Items_062520_Final.docx," which is one of the 2020 RA Study support documents).

[41] DEC RA Study p. 32.

58. It was correct to focus on 2016 to 2019, and to not use the data from 2014-2015, because the Companies have taken actions since the 2014 polar vortex event to prevent the high level of outages that occurred at that time. However, the description of this 400 MW for the 2016-2019 period is not correct and the 400 MW value is not supported.[42]

a. First, contrary to the quote above, there were no instances of temperatures below 10 degrees over 2016-2019. There was a single instance of 10.28 degrees.
b. Second, the 400 MW is not an "average"; it is based on the estimated cold-related forced outage on the single instance of 10.28 degrees, which occurred on the morning of January 2, 2018.
c. Third, note that this was a quite unusual date – the outage was very early Tuesday morning following a three-day New Year's weekend. Perhaps if this extreme cold had occurred under more regular circumstances the plant staff could have addressed the cold-related problems that arose without having to take a forced outage during the morning peak period of a day when extremely high loads were expected due to the extreme cold.

59. As DEC RA Study confidential appendix Figure CA3 clearly shows, cold weather outages during 2016-2019 were typically well below the 400 MW value across a broad range of low temperatures, with a few instances higher and other instances lower. If a larger set of instances of cold-related outages is considered, the average is considerably lower than 400 MW.

60. The cold weather outages assumption has a substantial impact on the RA Study results. According to the RA Studies' sensitivity analyses, removing

[42] 2020 RA Study support file "Feb 21 Follow-up Responses_032720_Confidential_Final cold weather outages."

the 400 MW of cold weather outages lowers the DEC and DEP reserve margins by 1.25% and 0.75%, respectively.[43]

61. While, as the RA Study recognizes, cold weather outages can be substantially higher or lower than 400 MW, it is important to keep in mind that the RA Studies perform probabilistic simulations, intended to estimate the likelihood of loss of load. Thus, all assumptions should either be probabilistic, or set at likely values rather than extreme values. Conservatism in planning is appropriate, but it should be transparent and based on unbiased analysis rather than baked into the underlying analysis through various conservative assumptions. I conclude that a value closer to 200 MW would be a better estimate of cold weather outages in future years for the purposes of the resource adequacy analyses.

62. The Companies should of course continue to strive to minimize the risk of outages under extreme cold when the capacity is needed the most. I also note that if the Companies were part of an RTO such as PJM or ISO New England, such outages would be subject to severe penalties, resulting in strong incentives to further improve power plant performance when it matters most.[44]

IV. OTHER CONCERNS ABOUT THE RA STUDIES

63. This section comments on a few other aspects of the RA Studies.

A. ECONOMIC RELIABILITY CALCULATIONS

64. While the focus of the RA Studies is on physical reliability calculations (to find the reserve margin that keeps LOLE below 0.1), and Astrapé recommends that the physical reliability metrics be used for determining planning

[43] DEC RA Study p. 54, DEP RA Study p. 54.

[44] See, for instance, PJM Interconnection, *Strengthening Reliability: An Analysis of Capacity Performance,* June 20, 2018, available at https://www.pjm.com/markets-and-operations/rpm.aspx.

reserve margins,[45] the RA Studies also present "economic reliability" calculations and results. The economic reliability calculations purport to reflect how expected customer cost varies based on planning reserve margins, and they result in the U-shaped curves shown in RA Study Figures ES1 and ES3.

65. This section explains why the economic reliability calculations are unreliable and no weight should be assigned to them. It further explains why, to the extent any attention is given to these calculations, the focus should be on "risk neutral" values, rather than values that assume customers should pay more over the long run to reduce potential high-cost outcomes.

i. UNLIKE PHYSICAL RELIABILITY CALCULATIONS, ECONOMIC RELIABILITY CALCULATIONS REQUIRE NUMEROUS QUESTIONABLE PRICE AND COST ASSUMPTIONS.

66. The physical reliability calculations, focusing on loss of load, are typically driven by assumptions based on historical data (load shapes, power plant outage rates). The economic reliability calculations require numerous additional price and cost assumptions that are not needed and not used for physical reliability calculations:

a. Cost of unserved energy (aka Value of Lost Load, or "VOLL"): a price assigned to the MWh of unserved energy due to inadequate resources.
b. External assistance: the prices at which such assistance may be available.
c. Scarcity pricing: how high scarcity prices rise as operating reserves fall to low levels.
d. Demand response strike prices: at what prices demand response is invoked.

[45] DEC RA Study p. 11.

67. The RA Studies set quite high values for these prices, and this drives customer costs very high under low reserve scenarios. But there is no clear and sound basis for setting the values for these parameters, and cases can be made for values across wide ranges. Unfortunately, very little sensitivity analysis was provided for these assumptions (and of the sensitivity analysis that was provided, some show results highly sensitive to these assumptions.[46])

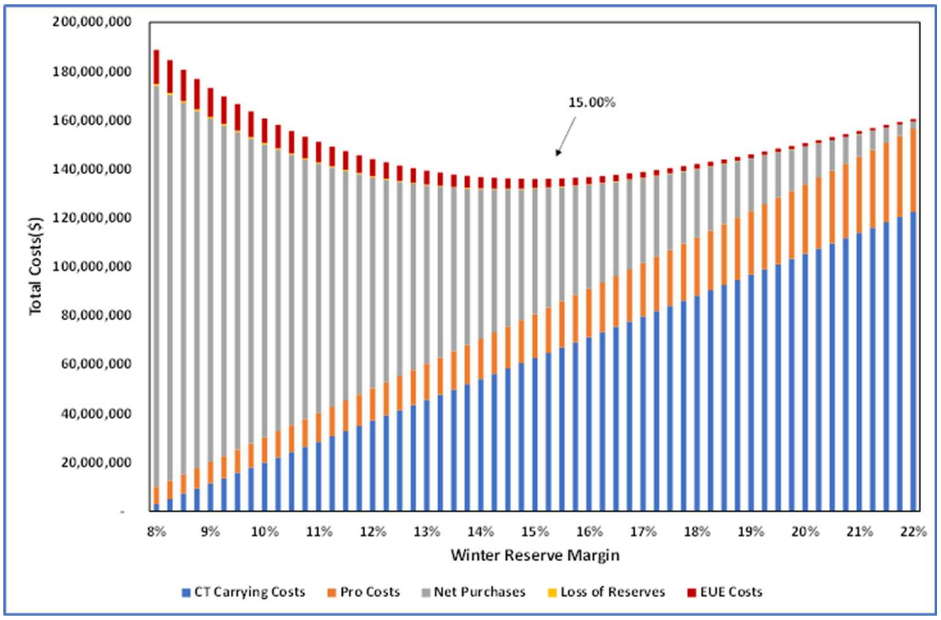
ii. HIGHER RESERVE MARGINS BASED ON PURPORTED CUSTOMER RISK AVERSION ARE NOT WARRANTED.

68. The lowest point on the U-shaped cost curves shown in the RA Studies' Figures ES1 (shown below, for DEC) and ES3, where customer cost is minimized, Astrapé usually calls the Economically Optimal Reserve Margin ("EORM").[47] However, as noted above, these cost curves are based on many rather arbitrary assumptions to which the results are sensitive. In addition, these curves are extremely flat; out of a total annual cost on the DEC system of approximately $1.5 *billion*, total cost only increases by about $3.5 *million* as planning reserves are reduced from 15% to 13%, or increased to 17%, according to the DEC RA Study's calculations.[48] Accordingly, the economic reliability analysis, whose results are summarized in these curves, provide only a weak basis for recommending the EORM, or any other specific reserve margin.

[46] See, for instance, DEP RA Study p. 60 Table 25 (showing a 4.75 % reserve margin difference depending upon whether VOLL $5,000/MWh or $25,000/MWh is used).

[47] See, for instance, The Brattle Group and Astrapé Consulting, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region*, prepared for ERCOT, October 12, 2018, p. 9.

[48] DEC RA Study p. 12 Figure ES1 and footnote 13, and workpapers to this figure.



69. Astrapé proposes focusing on reserve margins greater than the EORM, based on the 85th, 90th or 95th percentile of the calculated total system cost. The RA Studies suggest that this will "shield customers from extreme scenarios for relatively small increases in annual expected costs."[49] However, the higher reserves do not prevent or eliminate the extreme scenarios in the simulation; in fact, they have very little impact on those scenarios, according to the workpapers.

70. It is sometimes suggested that carrying additional reserve margin is analogous to paying for insurance. But this analogy also does not work. People pay for, say, home or auto insurance, because a car crash or home fire can have an extremely harmful impact on family finances. The insurance effectively removes the extreme impact, with the insured generally only paying a deductible, in addition to the insurance premiums. People are willing to pay for insurance, knowing they are likely to end up paying more on an expected value basis over the long term, because the potential impact of a crash or house fire can be so financially harmful.

[49] DEC RA Study p. 13.

71. Carrying a higher reserve margin is not at all like insurance. First, the extreme outcome due to a lower reserve margin would be a relatively high electric bill in a month when reserves fell to low levels. While such a bill might be high, it would not resemble the impact of losing a car or house. More important, carrying a bit more reserve margin, unlike insurance, would not eliminate the high bill, it would only reduce it somewhat. This is not at all similar to what insurance does.

72. The DEC RA Study also asserts (p. 15) that "Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEC is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1)." This is not correct. As the quote suggests, PJM incorporates its capacity market in order to achieve the one day in 10-year standard; but there is no assumption of risk aversion involved. And PJM would argue that its capacity market creates forward price signals that result in efficient capacity entry and exit decisions, and lead to its energy, ancillary services, and capacity markets together meeting customer needs efficiently.

73. The use of a higher percentile of cost rather than risk-neutral is based on the concept that customers should be willing to incur higher costs over the long term on average, in order to slightly reduce the magnitude of the very highest costs under the most unfortunate scenarios, should they ever occur. However, the RA Studies, in addition to exaggerating costs under the highest cost scenarios due to many questionable assumptions (as discussed above), also fail to account fully for the positive, indirect impacts of the high costs that occur under somewhat lower reserve margins.

74. Under the highest-cost scenarios, the very high costs are primarily a result of high unserved energy costs and high costs for purchases. The cost of purchases is dollars paid to purchase power from resources off the Companies' systems when loads exceed production. But the dollars paid for such purchases

go to utilities, public power entities, merchant power plant owners, or other entities in neighboring regions. If the dollars flow to a utility or public power entity, it is likely that the amounts in excess of production cost reduce the utility's customers' bills, which would benefit those customers. If the Companies' customers and the neighboring utility's customers were to sit down and discuss such bilateral assistance, recognizing the benefits that flow to customers when there are such high-cost purchases, they would recognize that their costs are jointly minimized at somewhat lower reserve margins than if such benefits are ignored.

75. The purchased power dollars might also go to merchant generators. In this case, the dollars will also encourage merchant power plant owners to maintain resources, and to develop additional resources, at their own expense, in order to be able to take advantage of such sales opportunities in the future. This additional merchant capacity will benefit the Companies' customers by creating additional reserves at no cost to them.

76. In addition, the high costs will provide incentives for other types of resources and demand response capability, including price-responsive demand, that may not be sufficiently encouraged or deployed if such episodes of high prices occur less often. This will further draw forth resources and resource flexibility, increasing efficiency and providing indirect benefits to customers.

77. In light of these benefits from episodes of high prices that are ignored in the RA Studies' economic reliability calculations, if any attention is given to these results, the focus should be on the risk-neutral EORM values.

B. Representing Economic Load Forecast Error

78. If peaks loads grow faster than forecasted (for example, due to stronger than expected economic growth), and resource quantities are not increased, it would result in actual reserve margins lower than were anticipated in resource plans published years in advance. The 2020 RA Studies include

probabilistic "economic load forecast error," intended to represent the possible error in four-year-ahead load forecasts (DEC RA Study, p. 27, DEP RA Study p. 28).

79. In the prior (2016) DEC and DEP RA studies this assumption had a substantial impact on the reserve margins: using instead a lower estimated forecast error based on one-year ahead load forecasts, the reserve margin declined by about 1%.[50] For the 2020 RA Studies the representation of load forecast uncertainty was modified, and this assumption now has only a very small impact on the reserve margins.[51]

80. My 2019 and 2017 reports criticized the representation of economic load forecast uncertainty on two grounds.[52] First, I explained why it is not appropriate to include *multi-year* economic load forecast uncertainty in the RA Studies, because the model used (SERVM) is unable to represent the short-lead-time actions that the Companies and market participants would take if stronger-than-expected load growth were to materialize and continue year after year. Second, I explained that the probability distribution of economic load forecast error used in the 2016 RA Studies was not supported by the underlying data it was based upon, and greatly overstated the risk of large and unexpected peak load under-forecast errors.

81. The 2020 RA Studies again attempt to rationalize using multi-year economic load forecast uncertainty, stating as follows: "Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans."[53] In support of this claim, the Companies refer only to the full process of developing a new power plant, from

[50] Duke Energy, *2016 Resource Adequacy Study – Outstanding Issues*, presentation in Docket E-100, Sub 157 December 12, 2017, slide 27.

[51] DEC RA Study p. 56, DEP RA Study p. 56.

[52] Wilson 2019 RA Report pp. 14-19, Wilson 2017 RA Report pp. 12-16.

[53] DEC RA Study p. 27.

"Develop an RFP for new capacity" through "startup and commissioning."[54] However, as explained in my 2019 and 2017 reports, this ignores the fact that there are many short lead time actions that can and very likely would be taken to expand resources or reduce peak load. If load grows faster than expected and raises concern about resource adequacy, the utilities (and customers and other market participants too) would have time to adjust their plans. To name a few potential actions, the development of some new resources might be accelerated; demand response or energy efficiency programs could be increased; a planned retirement could be delayed; firm purchases from adjacent regions could be increased; or wholesale sales contracts could be allowed to expire.

82. Using an estimate of four-year load forecast uncertainty in the RA Studies essentially assumes the reserve margin and resource plan must be chosen over three years in advance, and then the resource plan must remain frozen for three or four years, even if load growth is much stronger than expected year after year. This is not realistic, and is at odds with the Companies' business practices, including the biannual IRP planning cycle. The assumption that load can rise sharply and unexpectedly, but no adjustments to the resource mix can or would be made over three years, biases the planning reserve margins upward.

83. It is notable that PJM, in its resource adequacy analyses, acknowledges that resource plans can and would be adjusted as needed if load grows faster than expected. Accordingly, while PJM's resource adequacy analysis focuses on determining planning reserve margins for peaks over three years into the future, PJM represents only one year of economic load forecast error in its analyses.[55]

84. My 2019 and 2017 reports noted that it could be appropriate to represent multiple years of forecast uncertainty in a more sophisticated model

[54] Duke Energy Response to Data Request SELC 3-11.

[55] See, for instance, PJM, *2012 PJM Reserve Requirements Study,* p. 20 (explaining the rationale for using a forecast error factor representing one year of forecast error).

that is able to internally determine supply-side or demand-side adjustments over time as the load forecast and other resources change over time in the simulations. For instance, the Electric Power Research Institute's Over/Under capacity planning model, developed in the 1970s, had this capability.[56] Planning reserve margins for future years are somewhat smaller if it is recognized that supply plans can be adjusted over time if needed. However, the SERVM model that was used in the 2020 and 2016 RA Studies does not have the capability to represent any such contingent resource decisions. To represent multi-year load forecast uncertainty, but not the actions that would be taken to adapt resource planning over time as such uncertainty resolves, is a flawed methodology that can bias the result toward higher planning reserve margins. I again conclude that it was inappropriate to use multi-year load forecast uncertainty; it would be more appropriate to use one year of load forecast error.

85. Turning now to the load forecast error probability distribution, the 2020 RA Studies and 2016 RA Studies all used probability distributions for load forecast errors based on the historical forecasting errors reflected in the U.S. Congressional Budget Office ("CBO") U.S. Gross Domestic Product ("GDP") forecasts and applying a 0.4 elasticity of peak demand to economic changes.[57] My 2019 and 2017 reports questioned whether CBO GDP forecasting errors are a reasonable proxy for the applicable economic forecasting errors for the Companies' service territories, and also criticized the representation of economic load forecast error using a symmetric probability distribution.[58] The 2020 RA Studies now use a distribution that is a better fit to the underlying data, and this has reduced the impact of the load forecast uncertainty on the RA Studies' results.

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[56] Decision Focus Incorporated, *Costs and Benefits of Over/Under Capacity in Electric Power System Planning*, EPRI EA-927, Project 1107, October 1978.

[57] DEC RA Study p. 28, DEP RA Study p. 28.

[58] Wilson 2019 RA Report pp. 17-18, Wilson 2017 RA Report pp. 14-16.

86. It is also notable that economic forecasters now expect lower U.S. GDP growth than occurred over the past thirty years, which further shrinks the likelihood of large under-forecasting errors compared to the CBO history. According to the Federal Reserve Bank of Philadelphia's biannual Livingston Survey of approximately 25 economic forecasters, up until 2006, forecasters expected 3.2 percent per year GDP growth, but more recently the median expectation has been only 2.2 percent per year.[59]

87. While the economic load forecasting error assumption apparently had an insignificant impact in the 2020 RA Studies, I again conclude that it is inappropriate to use multi-year load forecast uncertainty in a model that cannot represent short lead-time adjustments, and I again question whether historical CBO GDP forecasting errors are a reasonable basis for estimating the Companies' potential load forecasting errors.

C. DEMAND RESPONSE ASSUMPTIONS

88. Historically, the Companies were summer-peaking, with loss of load risk, and capacity value, concentrated in the summer period.[60] The Companies therefore have historically designed their demand response programs to reduce demand on the hottest summer days of the year, and, as a result, have substantially more demand response available in summer than in winter.

89. The DEC RA Study assumed 1,122 MW of summer demand response and 461 MW of winter demand response (p. 37). An additional 500 MW of winter demand response would eliminate 60% of the winter load loss events in the simulations; 1,000 MW would eliminate 85%, allowing a considerably lower

[59] Federal Reserve Bank of Philadelphia, *Livingston Survey*, December 2020; releases from 1991 to present are available at https://www.philadelphiafed.org/research-and-data/real-time-center/livingston-survey.

[60] See, for instance, *Duke Energy Carolinas 2012 Generation Reserve Margin Study*, p. 14; Duke Energy Response to Data Request SACE/NRDC/Sierra Club 4-1c in Docket E-100, Sub 157.

winter reserve margin and shifting resource adequacy risk toward summer.[61] The DEP RA Study assumed 1,001 MW of summer demand response and 442 MW of winter demand response (p. 37). An additional 500 MW of winter demand response on the DEP system would eliminate almost 70% of the winter load loss events in the simulations; 1,000 MW would eliminate over 90%.

90. On hot summer days, loads can remain at high levels for several hours. The Winter Peak Study observes that, compared to summer peak days, winter peak loads are typically "steep" (of brief duration), and suggests that peak shifting is not likely to pose a real problem.[62] This suggests that, other things equal, winter demand response should be relatively effective in reducing winter peak loads.

91. This shows that the conclusion that resource adequacy risk is concentrated in the winter is not only greatly exaggerated due to the flaws discussed earlier in this report, it is also highly sensitive to particular resource mix assumptions, such as demand response, that can and should be adjusted for the future. Furthermore, as noted in the summary section of this report, the Winter Peak Study did not discuss the possibility of winter peak loads higher than the Study Peak Day, and did not identify or evaluate demand response programs tailored to mitigating loads greater than the Study Peak Day.

D. Model Estimates of Seasonal and Hourly Capacity Value Are Highly Sensitive to Assumptions That May Change

92. The estimates of the particular seasons, months, and hours where the risk of load loss is highest, based on the modeling approach documented in the 2020 RA Studies and 2018 Capacity Value Study, will be highly sensitive to various model assumptions that can change over time. Assumptions about the

[61] Duke Energy Response to Data Request ORS AIR 2-35(k).

[62] Winter Peak Study Task 2 Report p. 5.

penetration of seasonal resources such as wind, solar and demand response can shift the seasonal balance, and also shift the particular hours in which capacity is likely to be scarce. Tailored demand response programs, or energy storage capacity (such as storage associated with solar resources) can shave peaks or shift them to adjacent hours. Load shapes may also change, due to the penetration of new end-use technologies, or changes in customers' habits, such as usage of programmable thermostats. Various scenarios of these assumptions might suggest very different seasonal and hourly patterns for the modeled load loss.

93. Correcting the flaws in the 2020 RA Studies that overstate winter resource adequacy risk would shift risk back toward summer, as would higher penetration of winter demand response or wind resources, which tend to have higher output during winter peaks than summer peaks.

94. A more balanced seasonal weighting of resource adequacy risk is also suggested by the simple fact that the majority of high load hours are in summer on both systems. According to DEC's load forecast, 92% of the highest load hours (top 1%) are in summer; for DEP's load forecast, 60% of the top 1% load hours are in summer. [63]

V. SUMMARY AND RECOMMENDATIONS FOR FUTURE PLANS

95. The evaluation in this report leads to the conclusion that the 2020 RA Studies have substantially overstated winter resource adequacy risk. I again conclude that the recommended DEC and DEP planning reserve margins are unsupported and higher than necessary. If the flaws I have identified were even partially corrected, the 14.5% summer planning reserve margin that was in place until the 2016 IRP, which would provide a 16.5% winter reserve margin, would be more than adequate.

[63] Duke Energy Responses to Data Request Public Staff 1-2. These values are based on the forecasts for 2025 with EE.

96. The following flaws in the 2020 RA Studies inflate the winter resource adequacy risk and planning reserve margins:

a. The extrapolation approach to associating loads to extreme cold conditions leads to substantially overstating the highest winter loads; more accurate regressions more focused on colder temperatures suggest a much more moderate impact of extreme cold on load.

b. The questionable use of 39 years of weather data, equally weighted, that over-represents extreme cold that has not been seen, or only rarely, for decades.

c. The additional power plant outages under extreme cold are also overstated.

97. The RA Studies also include economic reliability calculations that are unreliable, and no weight should be assigned to them. To the extent any attention is given to these calculations, the focus should be on "risk neutral" values, rather than values that assume customers should pay more on average over the long run for additional capacity in order to potentially reduce infrequent high cost outcomes.

98. The economic load forecast uncertainty assumption has little impact on the RA Study results this time around, but the approach remains flawed. The application of multiple years of economic load forecast uncertainty is inappropriate in a model that does not represent the contingent actions that could be taken if load grows more rapidly than expected. Even accepting the application of multiple years of economic load forecast uncertainty, the use of CBO GDP forecast error data, as a proxy for Duke load forecast error, is highly questionable.

99. The Companies' approach to estimating seasonal, monthly, and hourly resource adequacy risk, seasonal capacity values of solar resources, and recommended reserve margins, reflected in the 2020 RA Studies, will be highly sensitive to various assumptions that can change dramatically in just a few years'

time, such as load shapes during summer and winter peak periods, demand response, and penetration of seasonal resources such as wind and solar.

100. Finally, this evaluation leads to the following recommendations for future IRPs and supporting resource adequacy studies:

a. If the Companies believe winter peak load spikes well beyond the Winter Peak Study's Study Peak Day may be reasonably likely, the Companies should extend the Winter Peak Study work to understand the customers and end uses that could potentially contribute to such extreme loads. If such research suggests that peaks may far exceed what was evaluated in the Winter Peak Study, the Companies should engage with customers and develop tailored programs for shaving these rare and brief spikes.

b. The Companies should study the relationship between extreme winter weather and load, and develop more sophisticated methods for estimating the potential impact of future extreme winter weather on load. The methods should take into account relevant factors, such as wind speeds, and will likely entail multi-hour temperature measures rather than simply daily minimums. The methods should also take into account that the most extreme temperatures will likely result in maximum use of space heating equipment at many homes and businesses, and closure or delayed opening of some facilities. An enhanced method for estimating how extreme cold weather impacts loads would be useful in multiple ways:

    i. A model of how extreme weather affects loads would be useful for anticipating and preparing for the types of high-load events that have occurred in recent winters. Extreme cold weather does not arrive by surprise - it is generally predicted days in advance. An accurate model of how an anticipated weather event will impact loads would assist the Companies in planning for such events days and hours in advance, and determining which actions to mitigate the peak are warranted.

ii. An improved understanding of how extreme weather affects loads would also assist in developing a more effective method for estimating historical weather-normalized peak loads, and for improving the forecasting of future peak loads.

iii. This research would inform the assumptions for future resource adequacy studies, and ensure consistency between load forecasting, resource adequacy modeling, and plans for managing winter peak loads.

c. The Companies should research the potential for load forecast errors due to economic forecast errors or other causes, and the realistic extent to which this could ultimately lead to less capacity than planned in a delivery year, also to inform future resource adequacy studies. Resource adequacy studies must be internally consistent in their assumptions in this regard – if the potential for adjustments to the resource mix in a one- or two-year ahead time frame are not modeled, only one year of economic load forecast uncertainty should be modeled.

d. The Companies should prepare additional load forecast scenarios (such as high and low scenarios), as required by South Carolina regulations.[64] The Companies should also prepare forecasts of extreme or "90-10" summer and winter peak loads, that is, the peaks that are expected to occur only once in ten years.

[64] SC Code § 58-37-40 (2019) (B)(1) "An integrated resource plan shall include all of the following: (a) a long-term forecast of the utility's sales and peak demand under various reasonable scenarios…".

e. The Companies should provide additional scenario analysis and sensitivity analysis of its RA studies, and allow stakeholders to request additional sensitivity analysis through discovery.

f. The Companies should consider defining an alternative metric for expressing and communicating target reserve margins, which might use, in the numerator, an aggregate capacity value measure (reflecting load carrying capacity rather than installed capacity). An alternative metric might also use, in the denominator, a 90-10 extreme (rather than weather normal) forecast peak load value. Reserve margin targets defined in such terms, which could be presented together with traditional installed reserve margin measures, would be more robust and stable over time as load patterns and the capacity mix change.

APPENDIX: QUALIFICATIONS OF JAMES F. WILSON

James F. Wilson is an economist and independent consultant doing business as Wilson Energy Economics, with a business address of 4800 Hampden Lane Suite 200, Bethesda, Maryland 20814. Mr. Wilson has 35 years of consulting experience, primarily in the electric power and natural gas industries. Many of his consulting assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. His experience and qualifications are further detailed in his CV, available at www.wilsonenec.com.

Resource Insight, Inc.

Implementing All-Source Procurement in the Carolinas

Duke Energy Carolinas & Duke Energy Progress

John D. Wilson, MPP
Research Director, Resource Insight, Inc.

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Natural Resources Defense Council, Sierra Club,
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Background and Purpose

All-source procurement is an approach in which a utility issues a Request for Proposals (RFP) in which all types of generation resources are allowed to compete, instead of issuing a RFP for a narrowly defined power plant to fill a specified capacity need. In *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement* (ASP Report), my co-authors and I suggested that, "All-source procurement means that whenever a utility (and its regulators) believe it is time to acquire new generation resources, it conducts a unified resource acquisition process. In that process, the requirements for capacity or generation resources are neutral with respect to the full range of potential resources or combinations of resources available in the market."[1]

Among the reasons that the Commissions should require Duke Energy to implement all-source procurement are to develop state electric plans that:

Provide an economic basis for scheduling the retirement of power plants, rather than waiting to act only when plants are already uneconomic;

Resolve technical and policy questions that affect bid evaluation in advance, rather than during regulatory approvals;

Obtain price and performance information about generation alternatives directly from the marketplace, rather than from Duke Energy's staff research;

Create opportunities to meet electricity supply challenges more efficiently with a blend of technologies, rather than considering one solution at a time;

Update methods for coordinating of generation investment decisions with development of other resources such as energy efficiency and transmission, rather than making investment decisions in silos;

Regulate the administration of the RFP process to ensure fair, efficient and competitive bidding with robust bid evaluation, rather than allowing for potential bias; and

[1] John D. Wilson, Mike O'Boyle, Ron Lehr, and Mark Detsky, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement*, Energy Innovation and Southern Alliance for Clean Energy (April 2020) , p. 6. (Hereafter, "ASP Report")

Expedite Commission certification of winning bids with a narrowed scope of review, reducing the risk of delay in heavily contested proceedings.

All-source procurement helps ensure that a utility arrives at the optimal resource mix, reducing costs and risks to customers. The approach I recommend will enable Duke Energy to:

- Obtain price and performance information about generation alternatives directly from the marketplace, and
- Identify unanticipated opportunities to meet electricity supply challenges more efficiently with a blend of technologies.

The use of market pricing to drive the model-based blending of technologies into a portfolio lifts the constraints of the utility's own cost assumptions and the capacity requirements that are required in conventional single-source RFPs. The additional opportunities made possible in an all-source procurement makes the outcome more robust and benefits customers by driving costs down and reducing the risks of stranded investments.

Experience in other states shows that all-source procurement is a proven approach that delivers clean, low-cost portfolios. The ASP Report reviewed four case studies of recent all-source procurements by vertically integrated utilities, and commented briefly on six other cases (including North Carolina). The ASP Report recommends best practices drawn from each of the case studies, but emphasizes the model used by the Colorado Public Service Commission.

The Colorado model is also recommended by the North Carolina Energy Regulatory Process' ("NERP") Competitive Procurement study group. The study group—co-chaired by representatives from Duke Energy and the solar industry—determined that the Colorado model "offered a good example of a successful generation procurement framework."[2]

Implementing All-Source Procurement in the Carolinas builds on the recommendations from the ASP Report and the NERP process, applying them to the integrated resource plans of Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP).

[2] North Carolina Energy Regulatory Process, *Competitive Procurement Guidance Document* (December 2020). (Hereafter, "NERP")

Duke Energy's IRPs include both a short-term action plan and a longer term forecast of potential new generation plants and other resource plans.[3] Generation plants identified in the short-term action plan are, for the most part, already approved or otherwise committed for construction or procurement. Thus, this report focuses on the process by which Duke Energy will procure generation resources in the years immediately following the short-term action plan.

The ASP Report shows how regulators have used the integrated resource planning proceedings to make an explicit determination of need in terms of the load forecast that needs to be met, evolving system operating requirements, and existing plants that may need to be retired. Regulators should use this ***total system need*** approach as the starting point for approving an all-source procurement.

Today, vertically-integrated utilities may procure resources through either all-source, comprehensive single-source, and restricted single-source RFPs. As explained in the ASP Report, "In contrast to an all-source procurement, in comprehensive and restricted single-source procurements, the resource mix is determined in a prior phase and the utility conducts resource-specific procurements for each resource to meet the identified need or needs."[4]

Although not discussed explicitly in the IRPs, Duke Energy intends to procure generation resources beyond the short-term action plan using a comprehensive single-source RFP process.[5] In addition to its statutorily mandated competitive renewable energy procurements, Duke Energy "considers the IRPs as the primary vehicle to determine and guide the procurement of generation resources to meet future customer energy needs with RFP solicitations. Competitive solicitations are used to identify the most cost effective and reliable resources available in the marketplace consistent with the IRPs."[6]

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[3] DEC and DEP file separate IRPs using a consistent methodology, publication format, and underlying assumptions. Both IRPs were submitted in identical form to the North Carolina Utilities Commission and Public Service Commission of South Carolina, along with supplementary materials reflecting each state's unique filing requirements. References citing "DEC and DEP" throughout this report are to their respective 2020 IRPs. Where a single page number is cited, the reference is to the DEC report pagination. References to Duke Energy's responses to any "DR" are responses to data requests filed in NCUC Docket E-100, Sub 165 and SCPSC Dockets 2019-224-E and 2019-225-E by the identified party. No confidential information is included in this report.

[4] ASP Report, pp. 2-3.

[5] Duke Energy's description of its RFP process is provided in the ASP Report, Appendix D.

[6] Duke Energy, response to SELC DR-8-5.

Duke Energy's IRP lays the foundation for issuing an RFP in late 2021 to obtain about 900 MW of peaking resource capacity for delivery in 2026, likely including performance specifications that will result in restricting the procurement to gas combustion turbine (CT) units. In addition, Duke Energy will continue and potentially expand the competitive procurement of renewable energy mandated under North Carolina law and permitted under South Carolina law over the next several years. Other generation resource needs would be subject to further procurements, potentially after future IRPs update Duke Energy's plans.

Relying on single-source RFPs for resources delivered in 2026 and beyond will not lead to the least-cost solution because the resulting portfolio is created by Duke Energy's assumptions about price, performance, and availability of generation alternatives. Even if each individual RFP results in competitive outcomes, the overall process will not take advantage of competition among technologies, and potential synergies across technologies.

Using an all-source procurement approach would involve considering bids to meet the ***total system*** need, including the 6,000-9,300 MW of winter rated capacity identified from the IRPs over the 2026-2031 timeframe in a single, coordinated process.

Unless the Commissions direct Duke Energy to adopt an all-source procurement process, Duke Energy will continue to utilize a suboptimal process. This report examines Duke Energy's need for an all-source procurement, the ways in which an all-source procurement would benefit customers, and the steps that the Commissions should take to implement an all-source procurement.

Determining the Need for an All-Source Procurement

How should the Commissions define the procurement need?

In conventional procurements, such as Duke Energy's prior RFPs, utilities specify a numeric capacity need (or goal) and technology eligibility, either by name or by restrictive performance standards. A well-designed all-source procurement takes a very different approach: the advance determination of need does not establish the specific capacity or technology to be procured.

The ASP Report recommends that regulators use resource planning proceedings to make an explicit determination of need – but ***define total system need in terms of the load forecast that needs to be met, and existing***

plants that may need to be retired.[7] Thus, system need should not be defined simply in terms of a specific energy or capacity target, but rather in terms of all system needs—and that should encompass many aspects of what can be called system operating requirements,[8] such as needs for flexible capacity, system inertia, and, simply, lower operating costs. The Commissions should approve the load forecast, including all related methods and assumptions, and the method for evaluating retirements of existing plants. Ideally, the determination of need would ensure that the procurement is open to any technology, and any siting location.

The resulting portfolio should satisfy the need created by the forecast, evolving system operating requirements and retirement options, with the utility procuring any amount of nameplate capacity of a mix of technologies based on cost-effectively meeting the need. The ***total system need*** can give a more optimal result because it is more expansive and less restrictive than a specific, numeric capacity target and technology specification.

When does Duke Energy's IRP anticipate procurements?

Using a conventional definition of need, DEC identifies its first year of need as 2026 and DEP as 2024.[9] Duke Energy's anticipated procurements are defined in various ways in the IRP.

DEP lays the foundation for issuing an RFP in late 2021 to obtain about 900 MW of peaking resource capacity for delivery in 2026, likely including performance specifications that will result in restricting the procurement to gas combustion turbine (CT) units. In addition, both DEC and DEP will continue the competitive procurement of renewable energy mandated under North Carolina law over the next several years.

Thus, even though DEP identifies its "first year of need" as 2024, Table 1 shows that DEP does not forecast resource additions until 2026 in its base case. DEC identifies its first year of need as 2026, but does not forecast substantial resource additions until 2030.

For purposes of this report, I am identifying 6,000 MW as the conventional definition of need that Duke Energy anticipates procuring, and I am assuming

[7] ASP Report, p. 20.

[8] Examples of relevant system operating requirements are discussed in Appendix B, such as renewable interconnection limit, rooftop solar forecast, DSM programs, joint planning/balancing, availability of pipeline capacity, and reserve requirements.

[9] DEC and DEP, Ch. 13, p. 113.

that any procurements would begin delivering resources in 2026. The capacity figures in Table 1 reflect Duke Energy's assessment of resource contribution to winter peak. Duke Energy recognizes solar systems as providing winter peak capacity of 1% of nameplate capacity. For example, in 2025 the 0.75 MW of solar represents 75 MW of nameplate solar capacity.

Table 1: Winter Capacity Resource Additions, 2024-2031 (winter-rated MW)

	2024	2025	2026	2027	2028	2029	2030	2031
Duke Energy Carolinas								
Combined Cycle								
Combustion Turbine							457	457
Solar		1	1	1	1	20	20	20
Battery								
Compliance Renewables	9	(14)	2	30	24	29	14	9
Duke Energy Progress								
Combined Cycle					1,224	1,224		
Combustion Turbine			457	457		913		
Solar							38	38
Battery								457
Compliance Renewables			(9)	19	18	14	(4)	11
Total Resource Additions	**9**	**(13)**	**451**	**507**	**1,267**	**2,200**	**525**	**992**

DEC and DEC Tables 12-E. "Compliance Renewables" calculated as the net change in cumulative renewables capacity (removing undesignated solar and battery).

How soon does Duke Energy believe plant retirements could be advanced?

While it is reasonable to assume that Duke Energy's nuclear, gas and hydroelectric resources will continue to operate for their expected license terms or until fully depreciated, the high fixed costs associated with maintaining coal plants can result in accelerated retirement dates. The potential to cost-effectively replace coal plants is an additional source of resource need in addition to power contract expirations and load growth.

In this IRP, Duke Energy conducted a coal plant retirement analysis to determine the most economic retirement dates.[10] Although these retirement dates are used in Duke Energy's base cases, Duke Energy states that these dates are not a commitment to retire in those exact years. Duke Energy also considered how early retirement could be advanced based on the timeline to bring replacement natural gas generation into service at the same location.[11]

If Duke Energy advanced coal unit retirements to those "earliest practicable retirement dates," then the net increase in conventionally defined capacity need would be about 3,300 MW, as summarized in Table 2. Any procurements to advance these retirements would begin delivering generation in 2026.

Table 2: Advancement from Economic to Earliest Practicable Retirement, 2024-2031 (winter-rated MW)

	2024	2025	2026	2027	2028	2029	2030	2031
Duke Energy Carolinas								
Marshall 1 – 4					2,078			
Belews Creek 1 & 2						1,220		
Duke Energy Progress								
Mayo 1			746			(746)		
Roxboro 1 & 2					1,053	(1,053)		
Total Retirement Advancement			**746**		**3,131**	**(579)**		

DEC and DEC Tables 11-A and.A-11.

Considering both Duke Energy's evaluation of anticipated procurements and the earliest practicable retirement dates, Duke Energy's total procurements could be as large as about 9,300 MW (winter-rated capacity) between 2026-3031.

[10] DEC and DEP, Ch. 11.

[11] DEC and DEP, Appendix A, pp. 173-176.

How does resource cost uncertainty affect the need determination?

Duke Energy's evaluation of the anticipated procurements and the economic retirement dates are outputs of its IRP modeling, which depends on its forecasted cost of new generation. If the forecasted cost of new generation declines, then the economic retirement dates for some plants should advance to an earlier date. Similarly, if new generation costs decline, then it will be cost-effective to advance or increase procurements and reduce the dispatch of existing generation resources. Thus, cost forecasts for new generation resources are a critical input into the need determination.

Relying on Duke Energy's IRP cost forecasts is likely to lead to the "wrong" procurement, potentially resulting in stranded costs that could have been avoided with a better cost forecast, or s a more competitive procurement process.

As discussed in Appendix C, forecasts of clean energy technologies have often wildly overestimated costs – and even though Duke Energy is forecasting substantially lower clean energy costs in the future, it may still be far too gradual.

Duke Energy even acknowledges that market pricing can differ so much from IRP cost forecasts that a comparison "yields little value in planning space."[12] Whether due to an erroneous forecast of market prices or to the cumulative effect of advantageous pricing due to "unique circumstances," when Duke Energy's "planning space" fails to represent the marketplace, its IRP forecast of capacity needs will inefficiently blend technologies.

The solution is demonstrated in all-source procurement case studies, which show the benefits to a utility that:

- Obtains price and performance information about generation alternatives directly from the marketplace. The PNM all-source procurement received 735 bids – developers are clearly willing to participate in highly competitive procurement.
- Identifies unanticipated opportunities to meet electricity supply challenges more efficiently with a blend of technologies. Xcel Colorado needed to replace 660 MW of coal plants, but was offered over 58,000 MW (nameplate) of generation resources and procured 2,458 MW, representing 1,100 MW of firm capacity.[13]

[12] Duke Energy, response to SELC DR-8-1(d).

[13] ASP Report, p. 33.

In a single-source procurement, generation cost forecasts are key assumptions in the model used to determine the capacity objective, or "need," of the RFP. If battery prices decline by 80%, rather than 50%, Duke Energy's plans for resource procurement will be outdated and misaligned in terms of cost, schedule and price – likely resulting in procuring the "wrong" resources. These problems can be mitigated by obtaining market-based pricing at the exact time that it is needed for evaluation and contract negotiation by Duke Energy, or any other vertically integrated utility. To minimize the impact of generation cost forecasts on the RFP, the ASP Report recommends what this report is referring to as a ***total system need*** approach to need determination.

What is the total system need approach to need determination?

The ***total system need*** approach to need determination will require the Commissions to oversee a process that ensures close scrutiny of the utility's assumptions about future electric load (including energy efficiency programs); operation of the existing generation fleet and transmission system; and relevant government policies. These activities are already part of the IRP process, but in addition to applying closer scrutiny, it is likely that regulators will need to require the utilities to make some adjustments.

Future electric load

Future electric load in the context of designing a procurement process is probably best considered as net load: customer electric usage (reflecting the reductions from energy efficiency programs and regulations) minus the power supplied by customer-funded distributed energy resources (DERs).

The ASP Report did not identify cases in which utility-funded energy efficiency programs or customer-sited DERs were procured through an all-source RFP.[14] Those customer-side resources require different evaluation approaches than utility-side resources and are thus not well suited for procurement in the same RFP. Estimating the scale of the customer-side resources requires in-depth scrutiny of program marketing and delivery plans, as well as market potential. A wide range of participant costs and benefits should also be taken into account in estimating program uptake and in evaluating the economics of the measures. In comparison, an all-source procurement for generation resources can expect a number of similarly-

[14] Demand response programs are an exception as discussed below.

qualified developers to offer competitive pricing, enabling the final evaluation to rely on quantifiable differences.

Even though the challenges to including most energy efficiency and DERs in an all-source procurement may not be easily overcome, the Commissions should enhance the connection between Duke Energy's generation procurement process and customer-based resources. An essential connection is ensuring that up-to-date procurement pricing information informs relevant policies and program management decisions.

Among those decisions are Commission reviews of energy efficiency programs, which should be authorized *at least* to the level indicated by the cost of generation resources. Energy efficiency programs can be modeled in system planning models with load shapes and cost information in comparison to generation bids to determine whether certain energy efficiency programs affect the optimal selection of bids. Such an integrated evaluation can then inform the Commission's review of utility-funded energy efficiency programs.

The Commissions should also require similar comparisons for tariffs and policies affecting customer-funded distributed energy resources.

Operation of existing generation fleet and transmission system

Duke Energy's approach to estimating the earliest practicable retirement date improves on its historical methods, and illustrates how changing economics can redefine the existing generation fleet and transmission system. Below, I will show how this approach can be leveraged to determine the retirement portion of the ***total system need*** approach to need determination. The Commissions should not neglect review of the "remaining" generation fleet and transmission system.

On one hand, the IRP models may need to be enhanced to better characterize evolving system operating requirements. For example, relatively crude assumptions regarding system inertia requirements, but greater reliance on resources that utilize "synthetic" inertia may require different modeling techniques. Other areas for enhanced modeling might include flexible capacity requirements, characterization of extreme weather events, and locational benefits of generation.

On the other hand, existing IRP models may contain unreasonable assumptions about the existing system in the form of operating constraints.

For example, the PNM case study in the ASP Report discusses an all-source procurement involving replacement resources for a retiring coal plant. PNM's proposed portfolio was challenged, in part, based on how PNM constrained the model's consideration of imported power. The import limit is one of several model constraints that effectively favored the selection of gas resources over solar resources.[15] New Mexico regulators accepted the critique of intervenors, and approved an alternative portfolio with more solar power than PNM had recommended.[16] Similar model constraints are included in Duke Energy's IRP model and should be reviewed for reasonableness, such as its 500 MW/year solar interconnection limit.[17] The ASP Report recommends that the IRP proceeding be used to affirmatively resolve disputes over model constraints in order to expedite the evaluation of bids and approval of portfolios during the procurement process.[18]

Relevant government policies

Duke Energy's IRP includes two base cases, one with and one without a carbon policy. Although the two base cases differ, it is arguable that the carbon policies examined in the two base cases are not different enough, with the carbon policy case only reducing emissions by 10% more than the without carbon policy case by 2035.[19] For example, Nova Scotia Power's 2020 IRP considered a "comparator" case (based on existing policy), a net-zero 2050 case, and an accelerated net-zero 2045 case.[20] The three cases show similar greenhouse gas emissions reductions in 2030, but diverge sharply beginning in the early 2030s.

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[15] ASP Report, p. 26; New Mexico Public Regulation Commission, *Recommended Decision on Replacement Resources – Part II*, Case No. 19-00195-UT, June 24, 2020, p. 122.

[16] New Mexico Public Regulation Commission, *Order on Recommended Decision on Replacement Resources – Part II*, Case No. 19-00195-UT, July 29, 2020.

[17] Duke Energy, response to ORS DR-2-26(a).

[18] ASP Report, p. 24.

[19] DEC and DEP, p. 8.

[20] Nova Scotia Power, *2020 Integrated Resource Plan*, NSUARB Matter No. M08929 (November 27, 2020), p. 50.

To its credit, Duke Energy evaluated several alternative resource portfolios, including earliest practicable coal retirements, high wind, high SMR, and no new gas generation, as well as several sensitivity analyses.[21]

Just as fuel cost forecasts presume that market prices will evolve based on known resource or technology characteristics, the government policy forecast used to inform the ***total system need*** determination should not presume the status quo. Locking in today's conditions for the future electric grid is a recipe for the creation of stranded costs.

Instead, the forecast should anticipate how government policy and other external requirements will shape the electric system.[22] Arguably, it is an extreme assumption to assume that the regulatory landscape will remain unchanged for the next decade or two. During the IRP process, the Commissions should give Duke Energy clear direction as to what government policies and related model assumptions be used in the IRP model for both planning and bid evaluation purposes.

Conducting an All-Source Procurement

What is an all-source procurement, and how is it authorized?

"All-source procurement means that whenever a utility (and its regulators) believe it is time to acquire new generation resources, it conducts a unified resource acquisition process. In that process, the requirements for capacity or generation resources are neutral with respect to the full range of potential resources or combinations of resources available in the market."[23]

The previous section discusses how the Commissions should implement the ASP Report recommendation that regulators use resource planning proceedings to make an explicit determination of need in terms of the load forecast that needs to be met, and existing plants that may need to be retired. Once the ***total system need*** is approved by the Commissions, Duke Energy would use that need determination as the starting point for approving an all-source procurement.

[21] DEC and DEP, Ch. 12, p. 89.

[22] Carbon policy is not the only relevant consideration. The Commissions' view on state policies, such as North Carolina's "Ridge Law," will have a significant impact on eligibility and bid evaluation.

[23] ASP Report, p. 6.

The ***total system need*** determination is one of several characteristics that differentiate all-source procurements from other procurement practices. Other important characteristics are a procurement that:

- Provides an economic basis for scheduling the retirement of power plants, rather than waiting to act only when plants are already uneconomic;
- Resolves technical and policy questions that affect bid evaluation in advance, rather than during approval hearings;
- Obtains price and performance information about generation alternatives directly from the marketplace, rather than from utility staff research;
- Creates opportunities to meet electricity supply challenges more efficiently with a blend of technologies, rather than considering one solution at a time;
- Updates methods for coordinating of generation investment decisions with development of other resources such as energy efficiency and transmission, rather than making investment decisions in silos;
- Regulates the administration of the RFP process to ensure fair, efficient and competitive bidding with robust bid evaluation, rather than allowing for potential bias; and
- Expedites Commission certification of winning bids with a narrowed scope of review, reducing the risk of delay in heavily contested proceedings.

The resulting procurement should differ from a conventional single-source procurement—the amount of resources procured may differ in both the mix and the capacities of each technology required from what was projected in the initial modeling.

North Carolina laws and regulations

North Carolina has three requirements related to procurement. First, NCUC Rule R8-60 requires investor-owned utilities to discuss the results of RFPs in their IRPs, but without any specific performance requirements.

Second, NC GS 62-110.1 requires the utility to obtain a certificate that demonstrates that power plant construction is consistent with the NCUC's plan for generation capacity. Although the NCUC could adopt a process to guide utility RFPs as its plan for capacity expansion, its current plan is a compilation of orders and information from relevant proceedings.[24]

Third, and most significant, is the Competitive Procurement of Renewable Energy (CPRE) program, authorized by North Carolina HB 589 in 2017 (NC GS 62-110.8). Two solicitations have been completed for DEC and DEP.[25] The CPRE legislation is extensive, and resulted in detailed rules (NCUC Rule R8-71) governing the RFP process and bid evaluation.

All-source procurement could proceed under an expanded scope of the NCUC's annual plan for capacity expansion, relying significantly on the CPRE process for model rules.

South Carolina laws and regulations

South Carolina's laws and regulations governing competitive procurement are in transition due to the South Carolina Energy Freedom Act (Act 62, May 2019). In 2019, the SCPSC initiated a proceeding to explore rules for a competitive renewable energy procurement process under the authority of SCC 58-41-20(E)(2). Although the proceeding has been underway for over a year, it has been delayed over the question of whether establishing such a competitive procurement program is in the public interest.[26]

Act 62 also amended South Carolina law to permit the SCPSC to establish rules for conducting an RFP and evaluating the bids prior to applying for the certificate required to construct a power plant (SCC 58-33-10). However, the existing SCPSC Rule 103-304 has not been updated and provides little additional guidance beyond reference to the statute.

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[24] The NCUC files an "Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina," pursuant to NC GS 62-110.1(c). The report summarizes information from utility IRPs and information from other Commission records and files. This report may also be considered the Commission's "plan," and NC GS 62-110.1(e) conditions a certificate for constructing a generation facility on "a finding that construction will be consistent with the Commission's plan for expansion of electric generating capacity."

[25] DEC and DEP, Ch. 14, pp. 117, 123; Appendix E, and Attachments I and II. DEC's "First Year of Need" is stated as 2026. See discussion on page 3.

[26] SCPSC, Commission Directive, Order No. 2020-779 (November 18, 2020), SCPSC Docket No. 2019-365-E.

Duke Energy also identified a SCPSC order related to the Distributed Energy Resource Program as providing guidance for a 40 MW RFP.[27]

All-source procurement could proceed in South Carolina in a process that combines both Act 62 procurement processes into a single process.

Duke Energy's recent procurements

Duke Energy has conducted 13 RFPs since 2012, as summarized in Appendix A. Most of these have focused on renewable energy, particularly solar power. Two were focused on gas generation. None could be considered all-source procurements.

Some of the key features of the procurements include:

- Most were combined DEC/DEP procurements, with different goals for each utility.
- Most allowed for either power purchase agreements (PPAs) or turnkey ownership, but specific terms and preferences varied among the RFPs.
- Legislative requirements constrained the location and other qualifications.

Duke Energy's current RFP process is documented in Appendix D. Overall, the Competitive Procurement of Renewable Energy (CPRE) procurements demonstrate the most proactive review and oversight practices. In contrast, the other procurements were initiated by Duke Energy without obtaining pre-approval of the process, bid evaluation methods, or other essential terms.

Duke Energy's history of procurements demonstrates a preference for using comprehensive single-source RFPs to procure generation resources, a practice it intends to continue (see page 5). Duke Energy does not obtain pre-approval by either Commission for issuance of an RFP, "Unless required by statute or the respective Commission."[28]

Nonetheless, both Commissions appear to have authority to establish all-source procurement rules. North Carolina's CPRE procurement rules provide an excellent starting point that both Commissions could use to develop all-

[27] SCPSC, *Order Addressing Distributed Energy Resource Program and Approving Settlement Agreement*, Order No.2015-514, SCPSC Docket No. 2015-53-E, p. 14; and Order No.2015-515, SCPSC Docket No. 2015-55-E, p. 14. See, Duke Energy, response to SELC DR-8-2(a).

[28] Duke Energy, response to SELC DR-8-2(c).

source procurement rules. The Commissions could begin by ordering a pilot procurement process in the current IRP proceedings under statutory authority, following up with a rulemaking that incorporates any lessons learned from the pilot.

How should near-term procurements be conducted?

Prior to 2026, Duke Energy's short-term action plan envisions further renewable energy procurements. State policy driving these procurements includes the North Carolina Competitive Procurement of Renewable Energy (CPRE) program and South Carolina Act 62. These state policies will accelerate the pace of adopting renewable energy resources, which help lower fuel costs in the near term.

The CPRE program has procured two tranches, all solar (some projects including storage). A third tranche is envisioned, but its minimum size will depend on how much "transition" renewable capacity (projects with legally enforceable obligations to deliver power to Duke Energy prior to enactment of the CPRE program).[29]

The NCUC may expand the size and number of CPRE procurements, as HB 589 provided for:

> … the offering of a new renewable energy resources competitive procurement in an amount to be procured as determined by the Commission, based on a showing of need evidenced by the utility's most recent IRP approved by the Commission … N.C. Gen. Stat. § 62-110.8

South Carolina Act 236 also provides a vehicle for near-term expansion of renewable energy procurements. The SCPSC is authorized to"

> … open a generic docket for the purposes of creating programs for the competitive procurement of energy and capacity from renewable energy facilities by an electrical utility within the utility's balancing authority area if the commission determines such action to be in the public interest. SCC 58-41-20(E)(2)

The SCPSC has opened such a generic docket (Docket No. 2019-365-E).

Thus, both the CPRE and SC Act 62 provide a strong basis for further renewable energy procurements to provide fuel-free, zero-carbon resources that provide near-term ratepayer savings. Duke Energy has the capability and legal authority to conduct such procurements for resource delivery prior to

[29] DEC and DEP, Attachment II, p. 8.

2026—as 2026 is the first practicable year for resource delivery under an all-source procurement.

Even in the absence of a specific statutory mandate or other policy directive, there may be reasons to proceed with a renewable resource procurement. A competitive solicitation for renewable energy resources could result in procurement of fuel-free, zero-carbon resources, reducing fuel costs and displacing fossil generation for the benefit of ratepayers. The SC PSC recognized this in its recent order on the Dominion South Carolina IRP, finding that:

> Even in the absence of a need for additional capacity, procurement of energy from solar and/or storage resources in the near term may result in savings for ratepayers, if those resources can provide energy to the system more economically than existing generation resources or alternatives contemplated in the IRP. Competitive procurement of such generation resources creates an opportunity for ratepayer savings.[30]

Further, consideration should be given to whether earlier procurement of resources not immediately needed for capacity or energy is economically beneficial (e.g., to take advantage of an expiring tax credit).

Under the circumstances discussed above, either commission may find cause to authorize Duke Energy to issue a renewable RFP, subject to parameters established by the commission. It would be impractical to include deliveries earlier than 2026 in an all-source procurement pilot due to the timeline for delivering many resources. A solar procurement for delivery in the 2022-2025 timeframe could proceed in parallel with the more complex all-source procurement envisioned in this report, which is intended to result in procurement in the 2026-2031 period.

How should all-source RFPs be scheduled?

Even though DEP's "First Year of Need" is stated as 2024 in the IRP,[31] my review of Duke Energy's base case indicates that about 6,000 MW of procurements, plus the potential for an additional 3,300 MW of procurements

[30] Public Service Commission of South Carolina Order No. 2020-832 at 21, Docket No. 2019-226-E (Dec. 23, 2020), https://dms.psc.sc.gov/Attachments/Order/a4b59f43-e545-43bd-9f35-a846b7602c39.

[31] DEP, Ch. 13, p. 114.

to advance the retirement of coal units, are anticipated in the 2026-2031 timeframe.[32] (See pages 5-8)

As discussed above, Duke Energy currently has a clear preference for the comprehensive single-source RFP process (see page 5). For a new construction CT project to fill a winter 2026 need, Duke Energy states that the RFP should be conducted in winter 2021.[33] Without direction from the Commissions, it is likely that DEP will rely on its IRP submission as the basis to initiate a gas-only procurement—likely missing out on cleaner, cheaper resources that could meet system needs.

Because of DEP's imminent procurement plans, the Commissions should take immediate action to schedule an all-source procurement process. Taking a holistic, all-source procurement viewpoint will require the Commissions to consider the varying development schedules for potential resources. Some existing, uncontracted resources may be available nearly immediately. Solar or storage projects that are in varying stages of permitting and interconnection may also take a bit longer. And still further out, the development schedule for otherwise proven technologies, such as offshore wind, may lack a proven track record.

These scheduling considerations mean that the Commissions would need to resolve whether the all-source procurement should be conducted as a single RFP covering the entire ***total system need*** for generation resources in the 2026-2031 timeframe, or as multiple RFPs. The single RFP approach is described in the ASP Report's Model Process for Bid Evaluation.[34] However, since Duke Energy's procurement needs are so substantial, it could be impracticable to evaluate such a large RFP in a single pass through its IRP model.

On the other hand, breaking the procurement up into multiple rounds could compromise the goal of optimizing the entire resource procurement. Since the bids would only provide pricing for the immediate resource needs of each

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[32] It may be advisable to allow for delivery of a restricted class of technologies in advance of 2026. According to Duke Energy, "The portfolios in DEP utilizing the earliest practicable coal retirement schedule vary from those that use the most economic retirement schedule, having a significant buildout of batteries from 2022 through 2025 to facilitate the earliest practicable retirement of Mayo station." Duke Energy, response to NC Public Staff DR-7-4.

[33] Duke Energy, response to NC Public Staff DR-3-27.

[34] ASP Report, p. 31.

round, those resource choices would be optimized against Duke Energy's existing generic resource cost forecasts. As discussed above, I recommend giving generic resource cost forecasts as little consideration as possible.

In evaluating these two alternatives, the Commissions should consider recognition of technologies that require a longer lead time. Duke Energy's IRPs discuss offshore wind and zero emissions load following resources (ZELFRs) such as green hydrogen.[35] An approach that gives long lead time resources a market opportunity, with sufficient lead time, would be preferable to one that only permits projects that can be developed on the timescale of a gas-fueled power plant.

A staged process for bid evaluation

Taking the best of both options, I recommend that the Commissions direct Duke Energy to design and propose an approach that solicits bids to meet the ***total system need*** for the entire 2026-2031 time period, but evaluates, models and contracts in stages. The process could follow this approach:

- Open an RFP soliciting bids for delivery of generation resources in the 2026-2031 time period.
- After conducting an initial screening analysis, update the IRP model's generic resources to representing typical cost and performance data of the most competitive bids. Subdivision of technology categories may be appropriate to ensure consideration of varying performance opportunities.
- Model bids on a year-by-year basis, competing against generic resources in future years. For the 2026 bid year, the actual bids would compete against generic resources for 2027+.
- After evaluating all bids through 2031, construct portfolios for more advanced evaluation, as suggested in the ASP Report and discussed in more detail below (see page 31).[36]

The Commissions may need to allow Duke Energy to fine-tune the bid vs generic resource evaluation method during the bid evaluation process. If so, the fine-tuning should follow guidelines that prescribe a balance between:

- Optimizing among technologies;
- Optimizing across time;

[35] DEC and DEP, Ch. 16.

[36] See discussion of Colorado and New Mexico case studies. ASP Report, pp. 20, 26, 31.

- Committing to sufficient contracts for deliveries later in the period to attract bids for those years; and
- Maintaining future opportunity by reserving a portion of the economic portfolio to future generic resources, with re-solicitation in future RFPs.

Any fine-tuning should be reviewed by the independent evaluator and fully explained in the bid evaluation report (both topics are explored below, beginning at page 31).

To implement this staged approach, the Commissions should direct Duke Energy to propose a more detailed process and, after its approval, proceed to swiftly issue an all-source RFP for the delivery of generation resources in the 2026-2031 time frame. The alternative approach would be to focus on a more limited delivery period (e.g., 2026-2027) and rely on resource cost forecasts for longer-term procurements. As discussed above, relying on cost forecasts will compromise the goal of optimizing the entire resource procurement on market data.

In either case, Duke should anticipate following up with additional RFPs after each IRP.

What resources should be eligible to participate?

Although resource eligibility for an all-source procurement is simple in concept, there are several complications that require advance resolution. As discussed in the ASP Report, "the requirements for capacity or generation resources are neutral with respect to the full range of potential resources or combinations of resources available in the market."[37] On its face, this definition of eligibility encompasses considering solar (including dispatchable and hybrid configurations), wind (including offshore sites), biomass, combined heat and power, battery storage, imported power, natural gas, and any other market-ready technology that can be financed, developed and delivered on a reliable schedule.

Ensuring the neutrality of the requirements for proposed generation plants is essential because rules or practices adapted from single-source RFPs can disadvantage or exclude cost-effective bids. The ASP Report discusses the dominance of natural gas and sources of bias in utility resource

[37] ASP Report, p. 6.

procurement.[38] Generally speaking, vertically integrated utilities have a financial bias towards over-procurement of capacity, a financial bias towards self-built generation, and an organizational culture that currently favors gas-fueled generation. The best practice to remove bias and ensure a neutral RFP process is for Commissions to conduct advance review of procurement assumptions and terms, as discussed below (page 29).

Another practice the Commissions should consider is to proactively support the development of data and analytic methods necessary to support evaluations of near-term emerging technologies. For example, Duke Energy could begin commissioning meteorological towers to independently verify wind speed history in order to evaluate wind projects.[39]

In defining resource eligibility, the Commissions should also determine how to incorporate demand-side management resources and emerging generation resource technologies. These resource options can play a role in an all-source procurement, but with some limitations.

Demand-side management resources

Utilities are also gaining experience with considering third-party demand-side management (DSM) resources in comparison to generation resources. As discussed elsewhere in this report, there are practical reasons to procure utility-funded energy efficiency programs in a separate, but coordinated process. Third-party DSM developers can aggregate the actions of many customers into a virtual power plant, and some third-party programs can meet bid qualification standards on much the same basis as generation resources.

Third-party DSM programs are recommended in Duke Energy's studies of winter peak reduction programs. The studies place the greatest emphasis on dynamic rates, such as time-of-use (TOU) and peak time rebate (PTR), which must be implemented by the utility through tariffs and are therefore unsuitable for an all-source procurement.[40] The studies also give a positive recommendation to a residential and small business bring-you-own-

[38] ASP Report, pp. 13-18. These topics are further explored in John D. Wilson, Mike O'Boyle and Ron Lehr, "Monopsony Behavior in the Power Generation Market," *The Electricity Journal* 33 (2020).

[39] Duke Energy, response to Vote Solar DR-2-17.

[40] Dunsky Energy Consulting, *Duke Energy Winter Peak Demand Reduction Potential Assessment* (December 2020), p. 23.

thermostat (BYOT) program and a non-residential automated demand response (ADR) program.

A BYOT program pays customers an annual incentive to "allow direct response signals to adjust their smart thermostat temperature settings…"[41] Although BYOT programs are often offered through third-party DSM aggregators,[42] Duke Energy intends to implement its BYOT program using its own EnergyHub aggregation platform that is already being deployed for summer peak demand response.[43]

Even if Duke Energy was open to a third-party DSM aggregator, BYOT programs may be more suitable for a single-resource procurement process. Like some other types of third-party DSM programs, a BYOT program's operational characteristics may evolve as development occurs between the contract award and the delivery date. Also like some other third-party DSM programs, BYOT programs are also likely to require negotiation of proposal-specific measurement and verification methods. Programs with these characteristics are difficult to directly compare with generation resources during bid evaluation.

Non-residential ADR programs offer more potential for participation in all-source procurement. As explained in one of Duke Energy's studies,

> ADR programs involve a combination of innovative rates, programs and technology solutions where customers may choose from among different options designed to fit their needs. This solution may also apply to medium sized customers. ADR technology solutions typically require that participants have, or install, equipment that can be controlled remotely, such as a building energy management system that automatically adjust equipment operating parameters in response to pricing signals from advanced rates, such as critical peak pricing or peak time rebate offers.[44]

Presuming that Duke Energy offers effective dynamic rate designs, third-party DSM developers could offer bids to all-source procurement RFPs related to

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41 Tierra Resource Consultants, *Duke Energy Winter Peak Targeted DSM Plan* (December 2020), p. 41. (Hereafter, "Winter Plan") Provided by Duke Energy in response to Public Staff DR-5-6.

42 Tierra Resource Consultants, *Duke Energy Winter Peak Analysis and Solution Set* (December 2020), p. 57. (Hereafter, "Winter Solution Set") Provided by Duke Energy in response to Public Staff DR-5-6.

43 Winter Plan, p. 39.

44 Winter Solution Set, p. 24.

the installation and control of ADR equipment.[45] One advantage of using third-party DSM developers is that they can specialize in particular market segments (e.g., refrigerated warehouses). Third-party DSM developers can also offer customized combinations of incentives and participation requirements, in comparison to the utility's obligation to make the same offer to each customer.[46] This customized approach may yield different results on a per customer basis, but attract more widespread participation.

As with some other DSM programs, ADR programs may be sufficiently well-understood to be evaluated in comparison with generation resources. Where this report refers to "generation resources," that term is also intended to encompass easily-qualified DSM programs.

Nearer-term emerging technologies

Emerging technologies also require special consideration, when the finance, development, or delivery schedule cannot be reliably guaranteed in the response to the RFP. Offshore wind and SMRs are examples of emerging technology that Duke Energy evaluates in alternative portfolios. While offshore wind is a proven technology, the lack of development experience in North America means that the delivery schedule cannot yet be reliably guaranteed.[47] The development of SMR nuclear plants has not been demonstrated, and cannot be reliably guaranteed at any date.[48] In this IRP, Duke Energy added "SMRs, offshore wind, and pump storage … [to its alternative portfolios] manually after optimization of other resources such as solar, onshore wind, and CCs and CTs."[49]

As Duke Energy develops the capability to evaluate emerging technologies in its planning models, one approach it could take would be to maintain their consideration as generic resources until a developer is able to make a fully qualified RFP response. Even if a technology is not considered for deployment until several years after the all-source procurement period (e.g., 2026-2031), retaining such resources in the model influences the timing and

[45] A complication is existing policies that allow large commercial and industrial customers to opt-out of Duke Energy's DSM programs, which would complicate third-party enrollment of opt-out customers.

[46] Winter Plan, pp. 90-91.

[47] DEC and DEP, Appendix A, p. 178.

[48] DEC and DEP, Appendix A, p. 180.

[49] Duke Energy, response to NCSEA DR-7-3.

selection of other bids. For example, the model may favor offshore wind delivery in 2035 over potential delivery of wind from the Great Plains in 2031, exhibiting a need for the Commission to endorse supportive policies if it wishes Duke Energy to pursue offshore wind resources.

This suggests that when evaluating emerging technologies as generic resources, it may make sense to limit them to alternative portfolios. When submitting candidate portfolios to the Commissions for review, Duke Energy can include one or more portfolios that include generic emerging technologies. If the Commissions are sufficiently convinced of the value and viability of an emerging technology, they may approve bids included in that portfolio. A decision to approve an alternative portfolio would not make a commitment to develop any specific project, but it would place Duke Energy on a procurement path that is optimized around the emerging technology.

How should procurement with other resource development activities be coordinated?

Even though it is termed "all-source procurement," Duke Energy will continue to rely on other resource development activities. Among these activities are evaluation of longer-term emerging technologies, grid investments, and energy efficiency (and related) programs, as well as consideration of existing zero-carbon facilities. In adopting all-source procurement, the Commissions should renew existing coordination mechanisms and may need to develop new practices.

Longer-term emerging technologies

Although nearer-term emerging technologies can be incorporated into an all-source procurement process, longer-term emerging technologies require even greater speculation on performance and cost. Relying on such assumptions in a procurement process can significantly affect near-term procurement decisions, and thus represents a major policy decision.

Duke Energy's discussion of ZELFR and other investments "needed to accelerate CO_2 reductions and sustain a trajectory to the Company's net-zero carbon goal" emphasizes that action is required now in order to complete such a dramatic and essential transformation.[50] The IRP process is an appropriate

[50] DEC and DEP, Ch. 16, p. 131. Duke Energy further states, "achieving an aggressive 70% reduction from the 2005 baseline requires emerging technologies such as battery storage, offshore wind, and SMRs. Other ZELFR technologies such as hydrogen turbines or advanced CCS were not considered in this IRP, but may emerge in the future and, as such, could be considered in future resource plans." Duke Energy, response to NCSEA DR-2-11.

venue for considering actions to reduce uncertainties around these technologies.

Duke Energy identifies uncertainties related to ZELFRs (and related storage technologies), that can be considered in three categories:

- Nearer-term generation resources, whose reliability is likely to be demonstrated in the market within the next decade, as discussed in the previous subsection;
- Grid investment technologies, discussed below; and
- Longer-term generation resources, whose availability depends on innovation.

Where the viability of an emerging technology depends on innovation, that innovation may be driven by production experience. As discussed above, learning rates relate declining costs to production experience. Technologies with high learning rates, such as battery storage, are likely to be nearer-term generation resources if there is already high interest and significant production.

The viability of longer-term emerging technologies with lower learning rates,[51] such as SMRs or hydrogen electrolysers, can be accelerated in several ways. The best understood acceleration method is to drive fundamental changes in key input prices.

For example, a substantial "green hydrogen" fuel supply could meet a number of needs, such as decarbonizing heavy industry and meeting long-term storage needs in a zero-carbon grid.[52] Electrolysers would become more competitive if electricity costs drop significantly,[53] and tax incentives can have much the same effect.[54] As discussed in Appendix C, RethinkX's future scenarios suggest this is a possibility. However, producing just today's hydrogen supply from electricity and water would require "more than the total annual electricity generation of the European Union."[55]

Basic science can also transform fundamental technology, repositioning it as a high learning rate technology. Supportive policy, such as government

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[51] Hydrogen Council, *Path to Hydrogen Competitiveness* (January 2020), p. 13.

[52] Hydrogen Council, p. 9.

[53] Hydrogen Council, p. 23.

[54] Duke Energy, response to NCSEA DR-2-7.

[55] International Energy Agency, *The Future of Hydrogen* (June 2019), p. 43.

research and development programs, can increase the prospects for breakthroughs.[56] Nevertheless, such transformations cannot be expected on any timetable, as demonstrated by the decades of research into fusion power.

Because of these substantial obstacles, emerging technologies without demonstrated high learning rates or other fundamental challenges should not be considered in IRP models except as alternative, speculative scenarios. In particular, they should not be included in Duke Energy's bid evaluation modeling as potential resources.

Grid investments

Duke Energy's Integrated System & Operations Planning (ISOP) is intended to optimize investments in resources such as transmission, distribution, and voltage optimization programs. The capability to expand renewable resources, energy storage, and imported power is closely linked to investment decisions resulting from the ISOP process.[57] Duke Energy's ISOP is still developing enhanced modeling capabilities that may enable more direct coordination in the evaluation of tradeoffs and synergies between grid, generation, and other resource investments.

Investments in some resources, such as energy storage and DSM programs, can help avoid the need for grid investments. Conversely, grid investments can open up grid access to cost-effective generation resources. This is particularly true for transmission-constrained resources such as imported power and offshore wind. One method for reducing Duke Energy's cost risk associated with transmission-constrained resources could be joining a regional organized power market.[58]

Duke Energy currently plans to integrate transmission and pipeline capacity analysis into its review for replacement of coal units.[59] The analysis Duke Energy describes appears to assume that gas plants will be required for replacement, as there is no discussion of how alternative technologies would be assessed.

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[56] Duke Energy, response to NCSEA DR-2-7.

[57] DEC and DEP, Ch. 15.

[58] Duke Energy, response to Vote Solar DR-2-24(c).

[59] Duke Energy, response to Public Staff DR-3-34.

Cost forecasts for the necessary grid investments are thus a necessary consideration in all-source procurement bid evaluations. This is an area where market-based pricing cannot replace Duke Energy's internal cost forecasts, since it is generally impractical to pursue an RFP for grid projects that might be needed to support certain potential generation bids. The Commissions should carefully review the basis for proposed grid investments, and ensure that Duke Energy is evaluating alternative investment levels and strategies concurrent with its evaluation of generation resource bids.

Energy efficiency, load management, and demand-side management programs

Energy efficiency (EE), load management, and demand-side management programs are cost-effective resources that help reduce the size of generation resource procurements. It is technically challenging to identify the optimal cost threshold, above which those demand-side resources become too expensive. This presents an economic coordination challenge for utility analysts.

Currently, the primary tool for coordinating generation resources with energy efficiency (EE) resources is the application of avoided costs in cost-effectiveness tests. These methods may also be applied to load management and demand-side management (DSM) programs. As discussed above (see page 21), dynamic rates and residential BYOT programs are recommended as winter peaking resources, but are best delivered through utility tariffs and single-source procurements. The discussion below applies to investment decision-making affecting all of these resources.

Cost-effectiveness evaluation of these programs is supplemented by limited modeling in the IRP, where Duke Energy modeled low, base and high EE portfolios. Although the high EE portfolio was determined to be cost effective, Duke Energy is concerned about "executability risk" and did not include the high EE portfolio in the base case.[60] As of yet, Duke Energy's IRP process has not proven to be an effective driver of EE resource investment decisions.

The use of avoided costs as a tool for coordinating EE program investments with generation resource costs may be challenged by the emergence of clean energy technologies and the adoption of a biennial all-source procurement process. Avoided costs are defined as the utility costs that are avoided due to

[60] DEC and DEP, Appendix A, p. 171.

adoption of EE programs, and include energy (fuel and other variable costs) and capacity (fixed costs, including power plant development).[61] Clean energy technologies, with very low variable costs, are likely to gradually drive down the avoided cost of energy on Duke Energy's system.

As clean energy drives the substitution of "steel-for-fuel," it might be assumed that the avoided cost of capacity would increase. However, the adoption of a biennial all-source procurement process, with contract deliveries extending out as far as 8 or 9 years into the future, could counteract that effect. Since generation resources that have been selected are no longer "avoidable," the forecast cost of committed resources is not normally considered in the evaluation of avoided costs.

Thus, if Duke Energy's IRP base case does not include a resource commitment to all cost-effective energy efficiency, the resulting increase in contracting for clean energy resources could drive down both the avoided cost of energy and the avoided cost of capacity. In turn, this would make EE resources appear less cost-effective in comparison to generation resources than is actually the case.

This problem could be compounded by other mismatches between the evaluation of generation resources and the evaluation of EE resources in the treatment of carbon policy (see page 30). Even though Duke Energy emphasizes its "base case with carbon policy," it is continuing to use the "base case without carbon policy" when determining avoided costs.[62] Together, these issues represent emerging risks to coordinated decision-making between supply and demand side investments.

One way to ensure that the all-source procurement process does not prematurely drive down avoided costs and the cost-effectiveness of energy-efficiency and other existing zero-carbon resources could be to provide for delivery flexibility in contracts resulting from the all-source procurement. This delivery delay could be requested (perhaps for a fee) by Duke Energy in the event that its ***total system need*** declines significantly. In addition to providing flexibility in the event of changes to the load forecast, allowing for delay, and thus avoidance, of costs would result in a more realistic avoided cost of capacity. Consideration of this issue in Commission policy, review of

[61] Avoided costs are also determined for other important regulatory purposes, notably compensating "qualified facilities" that sell renewable energy to Duke Energy under federal and state rate regulation.

[62] DEC and DEP, Tables 12-E and 12-F, pp. 100-101; response to ORS DR-3-1(d).

RFP documents, and updates to avoided cost methods could help maintain a reasonable coordination between generation and EE procurement activities.

Renewals and upgrades to existing zero-carbon facilities

Renewals and upgrades at existing zero-carbon facilities are a special challenge to an all-source procurement process.[63] In the case of renewals for existing power purchase agreements (PPAs), there is a question of timing. If an existing solar facility wishes to renew at mutually-favorable terms, its renewal may not be well-aligned with the RFP schedule, particularly over the next several years. This may be a particular concern for solar "qualified facility" projects.

A related issue is that some existing suppliers, such as those same solar "qualified facility" projects, may identify a mutually cost-effective opportunity to upgrade their facility to improve performance. For example, a solar project owner might upgrade inverter technology to offer ancillary services, or it might add solar panels or install a battery behind the inverter to improve on-peak production.

Not only suppliers, but also Duke Energy's own generation facilities will require similar evaluations. Duke's existing methods to evaluate the cost-effectiveness of major maintenance to sustain high levels of performance or output may require reconsideration.

To evaluate these opportunities, Duke Energy may need to continue to utilize an avoided cost method. This evaluation method will face the same challenges, with similar resolutions, as the EE programs discussed above.

What should be reviewed in advance?

One of the five best practices identified in the ASP Report is, "Regulators should conduct advance review and approval of procurement assumptions and terms."[64] Resolving technical and policy questions that affect bid evaluation in advance, rather than during approval hearings, can expedite the certification of winning bids. In Colorado, after the utility bid report is submitted to regulators, full evidentiary hearings are not generally required to obtain

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[63] Duke Energy's IRPs assume "existing solar contracts expire over the planning horizon they would be replaced with in-kind generation. This could include renewal of existing contracts or replacement of existing contracts with new solar generation." Duke Energy response to Public Staff DR-3-19.

[64] ASP Report, pp. 24-27.

approval for contracts or even utility-owned projects.[65] By narrowing the scope of review, the Commissions can avoid a contested, time-consuming post-evaluation process.

State regulators have met this challenge. As discussed above, New Mexico resolved model bias issues through an exhaustive review in a special proceeding (see page 11). Colorado regulators conducted a thorough IRP process that includes advance review of "RFP documents, model contracts, modeling assumptions that will be used to conduct the all-source RFP bid evaluation, the process by which transmission costs are factored in to bids, the surplus capacity credit (how to handle bids that aren't perfectly matched to need), backfilling (how to compare bids of various length) and other procurement policy matters."[66]

The Commissions' responsibility for oversight of modeling methods and assumptions will encompass a significant number of issues that have often been left to Duke Energy's discretion in its IRPs – as long as they were deemed reasonable for planning purposes. For bid evaluation purposes, a higher standard of review should be required. Appendix B summarizes several IRP modeling methods and assumptions and provides examples of how each issue might be resolved during the IRP process. While most are likely to be technical, some will require policy judgement or attention to the process for subjective consideration. The Commissions should develop a list of modeling methods and assumptions that will be resolved in the IRP process and direct Duke Energy to file an initial proposal.

One issue requiring the Commissions' policy judgement is carbon policy. Duke Energy states that its capability to achieve net-zero emissions by 2050 depends in part on its ability obtain policy support from state regulators.[67] Even though Duke Energy emphasizes its "base case with carbon policy," the "base case without carbon policy" will be used to determine RFPs and evaluate bids until the Commissions approves a carbon policy.[68] The Commissions should make an affirmative decision regarding the forecast for carbon policy (see page 11).

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[65] ASP Report, p. 37.

[66] ASP Report, p. 35.

[67] Duke Energy, response to Vote Solar DR-2-11.

[68] DEC and DEP, Tables 12-E and 12-F, pp. 100-101; response to SELC DR-8-5.

Another area requiring attention in the Commissions' final IRP approvals is the use of any "non-price" factors and attributes that require subjective consideration, either in determining whether a bid is qualified or potentially as a post-model evaluation ranking adjustment. For example, the Commissions might direct Duke Energy to consider mitigation of regulatory risks by including the social costs of air pollution with the direct costs of emissions allowances and operating costs of emission control equipment.[69] In the New Mexico proceeding discussed above, legislative direction to consider employment impacts from a coal retirement was a significant factor in selecting a portfolio (see page 11).

In order to build on proven success in conducting all-source procurements, the Commissions should consider directing Duke Energy to incorporate model documents from Colorado in its own all-source RFP materials. Of course, when considering the Colorado model, Duke Energy should also look to its own practices. As discussed above (see page 15), Duke Energy has conducted single-resource procurements, including gas peaking/intermediate contracts and the CPRE process for renewable energy – and I understand that Duke Energy relied on the Colorado model to design the CPRE process.[70]

Using the criteria discussed in the ASP Report and elaborated on throughout this report, the Commissions should encourage Duke Energy to blend familiar, proven practices with further adaptation of the Colorado model to meet the needs of the Carolinas.

How should bids be evaluated?

When the ***total system need*** determination is paired with a robust bid evaluation, the all-source procurement is clearly differentiated from the conventional single resource competitive procurement. As discussed above (see page 8), these two steps enable utilities to

- Obtain price and performance information about generation alternatives directly from the marketplace, and
- Identify unanticipated opportunities to meet electricity supply challenges more efficiently with a blend of technologies.

The use of market pricing to drive the model-based blending of technologies into a portfolio lifts the constraints of the utility's own cost assumptions and the capacity requirements that are required in conventional single-source

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[69] Duke Energy, response to Vote Solar DR-2-1.

[70] NERP Report.

RFPs. The additional opportunities made possible in an all-source procurement makes the outcome more robust and benefits customers by driving costs down and reducing the risks of stranded investments.

The ASP Report details how a robust procurement process can deliver these benefits in its a model bid evaluation process.[71] The Commissions should direct Duke Energy (or its independent administrator) to follow that process, as summarized briefly below.

- Screen bids for minimum compliance, and potentially remove less competitive bids from consideration.
- Evaluate the bids using the IRP system planning model, including both capacity optimization and subsequent production cost modeling.[72]
    - If authorized by the Commissions, make off-model adjustments to reflect resource-specific costs and benefits prior to input.
    - Apply the staged process for bid evaluation to facilitate consideration of bids over the 2026-2031 timeframe (see page 19).
    - Use the capacity expansion model to optimize among bids of all technologies.
    - Using model results, create and compare multiple resource portfolios, each composed of multiple bids. The Commissions may identify specific objectives that should be met by alternative portfolios, and Duke Energy may wish to build alternative portfolios reflecting future development of emerging technologies (see page 23).
- Further study portfolio costs using a production cost model. If there are concerns about reliability, further portfolio review in resource adequacy or power flow models may be conducted.
- Summarize evaluation results in a report, with all model data made available for review by regulatory staff and qualified intervenors.

This final bid evaluation report is the culmination of the process. As discussed above (see page 29), technical and policy questions that affect bid evaluation should have been resolved in advance. The bid evaluation report presents evidence that the utility has adhered to the agreed-upon methods and

[71] ASP Report, pp. 31-32.

[72] As shown in Appendix D, Duke Energy's current IRP process uses only production cost modeling. Appendix D, p. 3.

assumptions, and should streamline the approval process, as discussed below (see page 36).

The Commissions should identify any specific objectives that they wish to be included in alternative portfolios in the bid evaluation report. The importance of including alternative portfolios in the bid evaluation report is a practice modeled in Colorado and New Mexico, as discussed in the ASP Report.[73] Examples of alternative portfolios include:

- Utility recommendation
- High jobs / local resource preference[74]
- Compliance with non-binding state carbon reduction goals
- Include specific emerging technologies
- Higher levels of efficiency

Duke Energy's alternative IRP portfolios in its 2020 IRPs is an excellent illustration of this concept. All-source procurement would enhance Duke Energy's portfolios by building them with market data from bid proposals, not generic resources. In their approval of the bid evaluation report, the Commissions' decisions would select among the alternative portfolios, or direct further adjustments.

As discussed above (see page 14), the Commissions may wish to pilot this process in an initial all-source procurement, and then adopt a rule similar to the CPRE rule in North Carolina, also consistent with South Carolina's Act 62. Many of the specific parts of the CPRE rule (NCUC Rule R8-71) already reflect best practices discussed in the ASP Report. Relying on the CPRE experience should help build confidence in a new all-source procurement process.

[73] ASP Report, pp. 20, 26.

[74] For example, in the New Mexico case study, the state legislature established a preference for generation resources located in the vicinity of a retiring coal plant. ASP Report, p. 41.

How should fairness and objectivity be ensured, especially with respect to a utility's self-build proposals?

The ASP Report recognizes that regulators often allow utilities (and their unregulated affiliates) to participate in their own RFPs, and that regulators have a responsibility to proactively address structural bias and prevent improper self-dealing by utilities.[75] In some cases, regulators (or legislatures) have cited an interest in giving utilities the opportunity to acquire new assets through market procurements in order to avoid "hollowing out rate base."

Among the reasons that it might be in the best interests of a vertically-integrated utility for the utility to self-build generation are the existing control of an optimal site, advantages due to tax or other similar financial circumstances, and special requirements involving a high degree of coordination with a utility-managed grid improvement project. Often an unregulated affiliate is a highly competitive participant in markets across the country, so excluding it could result in a less competitive procurement. The NC Energy Regulation Process found that, "… there is value in diversity of generation ownership. A mixture of third-party ownership and utility rate-based ownership diversifies risk for customers and provides a variety of benefits."[76]

A good example of a situation in which Duke Energy may be the only feasible developer of a project is the ongoing 260 MW upgrade of the Bad Creek Pumped Storage Generating Station. Once the upgrade is completed, Bad Creek will have a capacity of 1,680 MW, continue to shift power from low to high net load hours, and the capability to adjust output to match load variations and help maintain voltage stability.[77] Where Duke Energy already controls an existing site, it is implausible that a third party would be in a position to offer further resource development. Nonetheless, such projects should be proposed in an all-source procurement process and only proceed if selected in a fair bid.

Citing a well-regarded 2008 NARUC report, the ASP Report summarizes five methods that Commissions should use to proactively address structural bias and prevent improper self-dealing by utilities, including:

[75] ASP Report, pp. 27-28. It may be either the utility itself, or an unregulated affiliate of the utility. Each requires proactive oversight by regulators.

[76] NCERP, p. 6.

[77] DEC and DEP, Ch. 16, p. 147; response to Public Staff DR-17-5(a).

- Involvement of an independent monitor or evaluator;[78]
- Transparent assumptions and analysis in a procurement process (see page 29);
- Detailed information provided to potential bidders;
- Utility codes of conduct to prohibit improper information sharing with utility affiliates;[79]
- Careful disclosure and review of "non-price" factors and attributes, particularly if they may advantage self-build or affiliate bids (see page 31).

As these practices appear to be incorporated into the CPRE process, the Commissions can build on experience by evaluating how effective they have been. In the process of adapting them to an all-source procurement context, any identified shortcomings can be addressed with a renewed commitment to ensuring fairness.

The ASP Report identified several other practices related to maintaining an objective and efficient process, some of which are discussed elsewhere in this report. One practice is that the all-source procurement process needs to have clearly established methods to address unforeseen circumstances. These may include utilization of the independent monitor's judgement, or may require rapid review of a proposed process deviation by the Commissions.

Another way to promote objectivity is to address issues of participation and information access. Providing detailed information to bidders helps drive down the ultimate cost of winning bids. In order to finance projects cost-effectively, project developers need to minimize sources of uncertainty that are viewed as risks by financial institutions. Utility concerns about revealing its maximum willingness-to-pay price should be very limited in a highly competitive procurement process where the competition's pricing isn't known. For this reason, the Commission should not just defer to the utility's claims of confidentiality when establishing reasonable protections for confidential information.

Furthermore, non-bidding stakeholders can have a constructive influence on the objectivity of the process. The Commissions should allow third parties to

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[78] The importance of independent oversight is emphasized in the NC *Competitive Procurement Guidance Document*. NCERP, p. 6.

[79] The importance of communications and separation protocols (modeled on CPRE) is emphasized in the NC *Competitive Procurement Guidance Document*. NCERP, p. 6.

participate in decision-making related to finalizing the RFP process and conducting the bid evaluation modeling process to help correct any bias that may exist within the utility's procurement staff. Of course, third parties should not have direct access to bidders' confidential proposals. An example of an area where third party input might be helpful is in determining whether a significant transmission upgrade required to support several competitive proposals should be included in the recommended portfolio, or only offered as an alternative portfolio.

How should portfolios be submitted and approved?

The final step in the model bid evaluation process is for regulators to approve or modify a resource portfolio.[80] Following the best practice based on Colorado's approval process, the Commissions should establish a procedure for approving or modifying a resource portfolio. The procedure should include a request for comments on the bid evaluation report from parties. The procedure should preserve the Commissions' option to conduct a full evidentiary hearing if significant concerns are raised, but should otherwise proceed based on the written record.

The viability of this specific approval process will depend on the Commissions' rules and preferences. If the Commissions conduct a full evidentiary hearing under conventional project certification statutes and rules, some of the benefit of advance review would be lost.

Multi-state approval

A major challenge to implementing a best practice all-source procurement process is the fact that both DEC and DEP operate in two states, and are thus regulated by both the NCUC and the SCPSC. Inconsistent decisions by the Commissions could lead to significant problems. Duke Energy discussed this issue as follows:

> Should the [South Carolina] Commission order a change to the base case in the IRPs that is not consistent with the North Carolina IRPs, it could result in systemic differences in valuations in other dockets.

[80] ASP Report, p. 32. The best practice also notes that, "If the Commission authorized multiple need scenarios, the decision should also explicitly identify the need scenario that it is relying upon." The use of multiple need scenarios to be considered in an RFP is an additional wrinkle discussed in the Colorado case study. ASP Report, p. 35. Multiple need scenarios will complicate the bid evaluation process, but could be useful if there is uncertainty about the feasibility of a retirement schedule due to reliability concerns.

> … NC and SC regulatory bodies have long treated resource planning in a consistent manner, implicitly recognizing the inherent benefits of the large geography and resource diversity enabled by generation in one state serves customers in another, even when faced with policy variations between the states regarding renewable energy (e.g., NC Senate Bill 3 (2007), SC Act 236 (2014), NC House Bill 589 (2017), and SC Act 62 (2019).
>
> To the extent that the utility commissions require different resource plans with different requirements to satisfy such plans, such requirements raise concerns about shared costs and benefits and may ultimately lead to cost shifting from one state to another, or even – if taken to a logical conclusion—a less optimal mix of resources that could ultimately cost customers more.[81]

One path to resolve this challenge could be for the Commissions to hold joint hearings to oversee the all-source procurement process. South Carolina law authorizes such a process.

> SECTION 58-33-420. Joint hearings with agencies from other states; agreements and compacts; joint investigations.
>
> The commission, in the discharge of its duties under this chapter or any other statute, is authorized to hold joint hearings within or without the State and issue joint or concurrent orders in conjunction or concurrence with any official or agency of any other state of the United States, ... The commission may request the Office of Regulatory Staff to make joint investigations with any official board or commission of any state or of the United States.

Joint hearings could be a very effective means of avoiding different requirements. Both Commissions would review the same evidence, and act on the same procedural schedule. Such an approach could minimize the chance that the Commissions would reach substantially different decisions, except where differing state laws directed such outcomes.

However, it is not clear that the NCUC has authority to hold joint hearings with the SCPSC. Under NC General Statute 110.1(c), the Commission may "confer and consult with … comparable agencies of neighboring states … and may participate as it deems useful in any joint boards investigating generating plant sites or the probable need for future generating facilities." Whether this authority would permit the NCUC to join the SCPSC in an joint evidentiary hearing is a matter for legal determination. Nonetheless, collaboration between the two Commissions and their staffs to the extent feasible should reduce the risk of creating different requirements that could be adverse to customer interests.

[81] Duke Energy, response to ORS DR-3-01.

The Commissions should consider what potential joint hearing options are available under existing law, and the NCUC may wish to inform the North Carolina General Assembly if it believes additional authority is required.

Appendix A: Duke Energy RFPs (2012-2020)

RFP	Requirement	Bids	Special Circumstances	Source
2012 DEC Capacity and Energy	700 MW dispatchable, non-peaking capacity and energy.	12 bidders provided multiple proposals. The DEC Lee Steam Station self-build proposal was selected.	Short-listed proposals were ranked utilizing production cost modeling.	DEC 2013 IRP, p. 41.
2014 DEC/DEP Solar	300 MW solar facilities directly interconnected to Duke Energy's retail service areas.	10 bidders provided 23 bids. DEP contracted for 9 projects totaling 283 MW.	Maximum PPA terms of 15 years, preference for turnkey asset projects larger than 20 MW.	DEC 2014 IRP, p. 45; DEP 2015 IRP, p. 80.
2015 DEC/DEP SC Shared Solar DER	5 MW solar facilities (250 kW - 1 MW) located in and directly interconnected to Duke Energy's retail service areas in South Carolina.	Unable to locate this information.	10 year PPA terms.	DEC 2016 IRP, p.57.
2015 DEC/DEP Utility Scale Program	53 MW PPAs for energy, capacity and RECs from 1 – 10 MW solar facilities located in and directly interconnected to one of Duke Energy's retail service areas in South Carolina in accordance with Act 236.	Unable to locate this information.		DEP 2016 IRP, pp. 57-58.
2016 DEC NC REPS Capacity	General RECs to meet REPS compliance	Executed contracts with 3 bidders.		DEC 2018 IRP pp. 24, 233

RFP	Requirement	Bids	Special Circumstances	Source
2017 DEC Wind	500 MW wind projects (minimum 100 MW) for delivered energy, capacity, and associated RECs.	Bids received were not economically valuable enough to pursue.	All types of delivery contracts considered.	DEC 2018 IRP pp. 27, 80
2018 DEC SC Utility Scale DER - **Supplement to 2015 SC DER Utility Scale**	40 MW PPAs for 1-10 MW solar facilities located in and directly interconnected to DEC's retail service area in South Carolina.	Six bidders provided 10 bids. Ten solar PV bids with only two bid as single axis trackers. Nine of the ten bids were shortlisted with six executing contracts with DEC.	Projects must be PURPA QFs and contract for a 20-year PPA. Must provide all associated renewable attributes, such as Renewable Energy Certificates, to comply with requirements under the South Carolina Distributed Energy Resource Program Act.	Duke Energy, response to SELC DR-8-1.
2018 DEC/DEP CPRE Tranche 1	680 MW CPRE-qualified renewable energy PPAs or facilities, including all renewable attributes, up to 80 MW in size, and interconnected to one of Duke Energy's retail service areas.	78 solar proposals, 4 also included storage 12 projects totaling 521 MW under contract, including 2 with storage		DEC 2020 IRP, Attachment II, pp. 6-7, 10.
2018 DEC/DEP Swine Waste Fueled	110 GWh[1] swine waste fueled biogas, electric power or RECs, with North Carolina REPS geographic constraints.	Seven proposals, two contracts and three under further consideration.		DEC 2018 IRP p. 79
2018 DEP	Near term need for	Ten bidders provided 32	Projects must commence	Duke Energy,

[1] This is a unique procurement since it procured energy, not capacity.

RFP	Requirement	Bids	Special Circumstances	Source
Capacity and Energy Market Solicitation	approximately 2000 MW of firm dispatchable peaking/intermediate capacity and energy resources resulting from expiring traditional purchase power agreements. Proposals must have a minimum capacity of 75 MW.	bids. • Combustion Turbine - 13 bids • Combined Cycle - 14 bids • Hydro- 2 bids • System (mix of resources) - 2 bids Six bids were selected (1-CC, 4-CT, and 1 Hydro). To date, 5 bids (1-CC, 4-CT) have executed contracts	between 2020 and 2023, concluding by 2028. Projects must meet Designated Network Resource requirements.	response to SELC DR-8-1.
2019 DEC/DEP NC Shared PV Solar	40 MW PPAs for 5 kW – 5 MW solar facilities located in and directly interconnected to one of Duke Energy's retail service areas in North Carolina.	No bidder responses No bids selected	Projects must be PURPA QFs and contract for a 20-year PPA.	Duke Energy, response to SELC DR-8-1.
2020 DEC/DEP CPRE Tranche 2	680 MW CPRE-qualified renewable energy PPAs or facilities, including all renewable attributes, up to 80 MW in size, and interconnected to one of Duke Energy's retail service areas.	43 solar proposals, 4 also included storage 12 projects totaling 689 MW selected		DEC 2020 IRP, Attachment II, pp. 7-8, 10.

RFP	Requirement	Bids	Special Circumstances	Source
2020 DEC/DEP DER Tier III - Solar Bids	53 MW asset transfers for 1-10 MW solar facilities located in and directly interconnected to one of Duke Energy's retail service areas in South Carolina in accordance with Act 236.	Four bidders provided 26 bids To date DEC/DEP has not selected any bids to develop, acquire and construct any SC solar facilities pursuant to the company's efforts under Act 236.		Duke Energy, response to SELC DR-8-1.

Abbreviations

CPRE – Competitive Procurement of Renewable Energy
DER – Distributed Energy Resources
PPA – Power Purchase Agreement
RECS – Renewable Energy Credits
REPS – Renewable Energy Portfolio Standard
RFP – Request for Proposals

Appendix B: Advance Resolution of Technical and Policy Issues

To implement the recommended all-source procurement process, the Commissions' responsibility for oversight of modeling methods and assumptions will encompass a significant number of issues that have often been left to Duke Energy's discretion in its IRPs – as long as they were deemed reasonable for planning purposes. For bid evaluation purposes, a higher standard of review should be required.

This appendix summarizes several IRP modeling methods and assumptions and provides examples of how each issue might be resolved during the IRP process. While most issues are likely to be technical, some will require policy judgement or attention to the process for subjective consideration. The scope of this appendix is intended to provide an indication of relevant issues and is thus an *incomplete* list of modeling methods and assumptions that should be resolved in the IRP process.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Resource Assumptions Resource assumptions can vary by supplier or specific project characteristics. Generic assumptions may bias the model away from otherwise preferred technologies.	The following resource assumptions are determined by Duke Energy staff in the Supply Side Data Manual.[3] Cost or price assumptions may be based third-party published date, on confidential and preliminary quotes, or on other sources. • Total plant cost • Plant EPC cost • Plant owner's cost • Land area required • Land lease/ownership costs • Assumed capacity factor • Seasonal maximum load • Seasonal heat rate, at varying load levels • Heat rate degradation factor	For the most part, these values should be provided in bids on a guaranteed basis. There may be limited exceptions (e.g., environmental reagent prices) that could be standardized similar to the fuel price forecast. Duke Energy's assessment of transmission infrastructure costs for each portfolio

[2] Text in this column may be a direct quote or a paraphrase.
[3] Duke Energy, confidential response to Public Staff DR-3-7.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
	• Variable O&M • Fixed O&M • Planned & unplanned outage rates • Book life • Environmental control technologies • Emission rates • Capital schedule for construction costs • Startup time • Ramp rates • Permitting & construction schedule • Water consumption • Environmental reagent usage and price • CHP steam output • Battery storage overbuild/augmentation • Battery storage total cycles • PV inverter loading ratio • PV degradation rate • Pipeline transportation costs (capital, O&M, or contract costs)[4] • Use of firm pipeline transportation or use of oil as backup for gas prices, including length of contract[5] • Transmission capital costs[6]	

[4] Duke Energy response to Public Staff DR-3-26.
[5] Duke Energy response to Public Staff DR-3-26.
[6] Project transmission capital costs are upgrade requirements required to accommodate power delivery. Additional transmission upgrade costs associated with the entire portfolio are discussed in the main body of the report. Duke Energy's transmission cost estimates are highly uncertain and may not usefully distinguish between the portfolios as their certainty is even lower than the "least amount of detail" under cost estimate classification guidelines. DEC and DEP, Chapter 5, p. 55; Duke Energy, response to NCSEA DR-2-25.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Fuel Price Forecast The evaluation of gas-fueled plants will depend on the fuel cost forecast, which should be identical for all such plants unless they are bid with fuel costs included. An unreasonable price forecast could bias the evaluation results.	The fuel price projections for coal and natural gas are constructed internally using market quoted fuel pricing data and IHS Markit Fundamental Fuel pricing data.[7] Natural gas fuel prices are lower for the newest, most efficient units than for older units.[8] Some existing gas CTs have additional pipeline transportation costs that are not assumed for future units.[9]	The Commissions should explicitly approve the fuel price forecast considering forecast alternatives proposed by the parties on their own merits. The Commissions should consider a preference for a forecast produced by an unbiased public source. The fuel pricing advantage for new units should be part of this review process.
Purchased Power Price Forecast The IRP model includes the opportunity to buy power on the short-term bilateral market. An unreasonable price forecast could bias the evaluation results.	Unable to locate this information.	The Commissions should explicitly approve the purchased power price forecast considering forecast alternatives proposed by the parties on their own merits. The Commissions should consider a preference for a forecast produced by an unbiased public source, if available.
CO_2 Allowance Price Forecast As discussed in the report, the Commissions' position on carbon policy is used to design RFPs and evaluate bids.	As discussed in the report, Duke Energy currently uses its "base case without carbon policy" to determine RFPs and evaluate bids.[10] Duke Energy's portfolios that include CO_2 allowance pricing use an internally developed projection based on factors including earliest likely timing of carbon policy legislation, growth rate to achieve de-carbonization levels, and method of CO_2 penalty.[11]	As discussed in the report, the Commissions should make an affirmative decision regarding the forecast for carbon policy.

[7] Duke Energy response to Public Staff DR-3-13.
[8] Duke Energy response to Public Staff DR-20-8.
[9] Duke Energy response to Public Staff DR-20-10.
[10] DEC and DEP, Tables 12-E and 12-F, pp. 100-101; response to SELC DR-8-5.
[11] Duke Energy responses to Public Staff DR-3-13 and NCSEA DR-7-4(a).

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Renewable Interconnection Limit and Related Resource Constraints Model constraints regarding the timing, quantity, and performance specifications of solar resources may result in suboptimal portfolios, unless the constraints are well-justified. Assumed charges may reflect controversial utility views.	Beginning in 2024, DEC and DEP were limited to 300 and 200 MW/year solar interconnections, respectively, and 150 MW/year wind interconnections.[12] In DEP, model selected solar was limited to solar paired with storage due to increasing likelihood of significant curtailment of incremental solar additions. Model selected solar included a Solar Integration Services Charge.[13]	The Commissions should determine if annual solar interconnection limits are necessary. Solar integration charges are approved in the avoided cost docket. RFP-eligible technologies should include “dispatchable” solar[14] which can be more valuable than take-or-pay solar which can only be curtailed.
Battery Storage Modeling The performance and scale of battery storage has the potential to substantially shift future resource procurements.	Standalone battery storage resources were not optimized in competition with other resources in the system planning model.[15] Instead, storage was selected in a later modeling step, apparently by testing replacement of CTs with storage.[16] Benefits such as ancillary services value are restricted to avoiding solar integration charges in when modeled as solar+storage.[17]	The Commissions should require standalone (and hybrid) storage resources to be eligible resources in the IRP. The Commission should require valuation of ancillary services and other grid operation services that can be delivered by battery storage. Additional emerging storage technologies may also merit consideration, as discussed in the report.

[12] Higher limits were used in alternative portfolios D, E, and F. Duke Energy response to NCSEA DR-7-4.
[13] Duke Energy response to Public Staff DR-3-18.
[14] See Energy and Environmental Economics, First Solar, and Tampa Electric Company, “Investigating the Economic Value of Flexible Solar Plant Operation” (October 2018), available at: https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf; National Renewable Energy Laboratory, First Solar, and California Independent System Operator, “Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant” (March 2017), available at: https://www.nrel.gov/docs/fy17osti/67799.pdf.
[15] DEC and DEP, Chapter 12, p. 90.
[16] DEC and DEP, Appendix A, p. 161; Duke Energy, response to NCSEA DR-7-6.
[17] DEC, DEP and Dominion Energy North Carolina, *Joint Report on Storage Retrofit Stakeholder Meetings*, NCUC Docket No. E-100, Sub 158 (September 16, 2020), p. 15.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Rooftop Solar Forecast The level of rooftop solar including in the IRP affects the ***load+retirement*** need determination, both in terms of the total energy requirement and in terms of the load shape.	The IRP discusses the rooftop solar forecast but does not provide technical details.[18] The rooftop solar forecast is the same in all portfolios.[19]	The Commissions should explicitly approve the rooftop solar forecast and may wish to request alternative portfolios with differing levels of rooftop solar. If the Commissions selected an alternative portfolio, that would exhibit a need for the Commissions to endorse supportive policy.
DSM Program Dispatch Prices and Capacity Benefit DSM programs may be lower cost than peaking resources such as gas CT and battery storage. Inaccurate (or suboptimal) pricing could result in suboptimal modeling. DSM programs vary in their effectiveness in performing on peak and by season.	Price assumptions for DSM program dispatch are confidential. Program-specific prices are based on internally determined benchmarks.[20] DR resources were counted at 100% of their capacity, even though a sensitivity showed that their load carrying capability is less than 100%.[21]	The Commissions should verify that DSM programs reflect either existing practice or reasonable assumptions about future program operations.

[18] DEC and DEP, Appendix C, p. 228.
[19] Duke Energy response to NCSEA DR-7-7
[20] Duke Energy confidential response to Public Staff DR-3-21.
[21] Duke Energy response to Public Staff DR-4-6.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Availability of Gas Pipeline Transportation Capacity Natural gas plants may require firm capacity in order to provide on-peak service. For plants without firm capacity, the utilization of the gas system during peak periods will determine the amount of oil required as a backup fuel.	Duke Energy reports that there is no unsubscribed existing firm natural gas capacity available. Duke intends to rely on new or upgraded capacity to increase its firm natural gas transportation capacity.[22]	The Commission should determine how bids of gas plants that depend on firm pipeline capacity should be reviewed. Options include requiring the bidder to be responsible for securing the capacity in advance and including an approved pipeline adder. An adder would require Duke Energy to obtain the firm capacity. In either case, the gas plant should bear the entire cost of any pipeline upgrades required. To avoid stranded costs, there should be no assumption that future pipeline users will cover any costs.
Resource Adequacy – Extreme Winter Weather The winter load forecast is sensitive to the relationship between cold temperatures and load. If this relationship is misstated, then the system planning model will over or under-procure resources to meet the winter peak load.	Duke Energy uses linear regression on recent historical temperature and load to extrapolate the peaks for extreme peak days. Extreme weather happens infrequently and there are likely temperatures in the last 39 years that were not seen in the five years of recent history.[23]	The Commissions should explicitly approve the method for relating extreme winter weather to loads.
Joint Planning and Balancing While DEC and DEP have a joint dispatch agreement, they file two IRPs because they are regulated as two separate utilities.	DEC and DEP file joint planning scenarios in their IRPs which demonstrate a significant potential to benefit from a unified IRP or merger of balancing areas.[24]	The Commissions should determine whether they wish an all-source procurement to be evaluated on the current basis, or with unified planning or a merger of balancing areas.[25]

[22] Duke Energy response to Public Staff DR-3-32.
[23] Duke Energy response to NCSEA DR-3-3.
[24] DEC and DEP, Appendix A, p. 199.
[25] Duke Energy response to NCSEA DR-4-2.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Load Following Reserve Requirement In addition to planning reserves, utilities maintain load following reserves to respond to short-term grid operation requirements. If the load following reserves are contingent on generation technology, then unreasonable methods for determining the requirement could bias the evaluation results.	Operating reserves modeled in Duke Energy's resource adequacy study include a regulation requirement, spinning requirement, non-spinning requirement and additional load following required for intermittent resources. Regulating reserves are used to cover the continuous fast and frequent changes in load and generation that create energy imbalance. Spinning and non-spinning reserves are contingency reserves used to maintain the balance of supply and demand when an unexpected event occurs. Load following reserves are additional reserves included to manage the variability of intermittent resources such as solar.[26]	The Commissions should explicitly approve operating reserve requirements. In cases where the operating reserve requirements are contingent on the performance characteristics of bids, a method for updating the relevant requirements should be explicitly approved.
Effective Load Carrying Capability The ELCC method assesses the contribution of variable and energy-limited resources (e.g., solar and storage) to meet peak demand. Increased use of these resources results in a declining ELCC. A mix of these resources results in a "diversity impact" such that the combined ELCC is greater than the sum of its parts. An incorrect ELCC value can result in too little or too much expectation that the procured resources will be available during periods of peak demand.	The IRP uses ELCC values calculated by Astrape for the 2018 (solar) and 2020 (battery storage) IRPs. The system planning model does not have the ability to calculate the ELCC dynamically depending on cumulative resources. The ELCC is calculated outside the model, presumably in an iterative manner reflecting the level of resources selected in the model.[27]	The Commission should explicitly approve ELCC studies, including their methods and assumptions, and the methods for applying them in the system modeling.

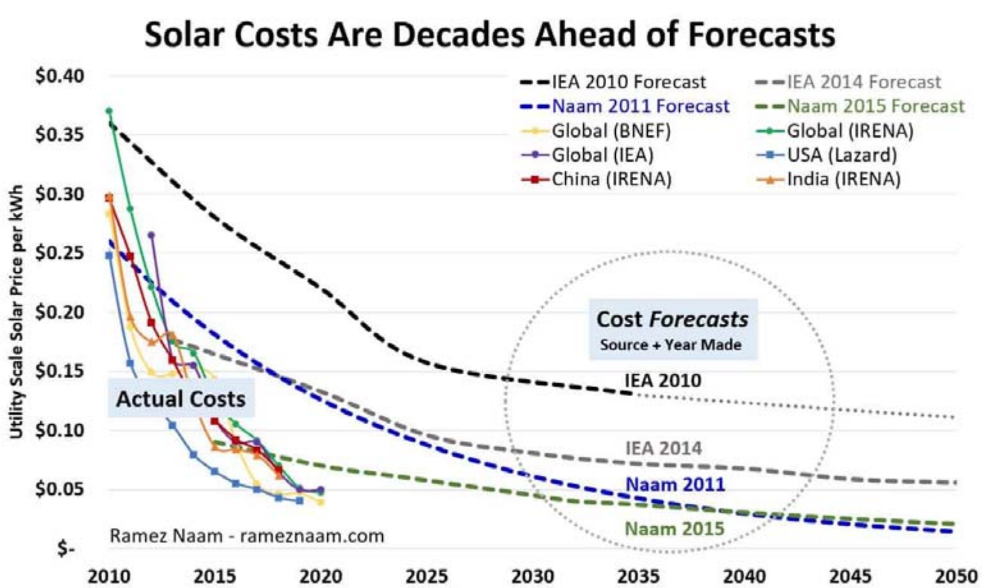
[26] Duke Energy response to NCSEA DR-10-1.
[27] Duke Energy rescponse to NCCEBA DR-3-1.

Appendix C: Advantages of Market Pricing Over Utility Cost Forecasts

Duke Energy's evaluation of the anticipated procurements and the economic retirement dates are outputs of its IRP modeling, which depends on its forecasted cost of new generation. If the forecasted cost of new generation declines, then the economic retirement dates for some plants should advance to an earlier date. Similarly, if new generation costs decline, then it will be cost-effective to advance or increase procurements and reduce the dispatch of existing generation resources. Thus, cost forecasts for new generation resources are a critical input into the need determination.

The problems with cost forecasts are illustrated by the track records of private and government forecasts of solar prices, which have wildly overestimated costs. Rocky Mountain Institute notes that, "in 2010 and 2011, when utilities were expanding coal mining operations and planning to build new coal-fired generating capacity, forecasts suggested 2015–2020 solar PV costs of $100–240/MWh—significantly higher than the anticipated costs of new coal assets at the time."[28] **Figure 1** illustrates that as recently as 2014, the International Energy Agency forecast that the unsubsidized cost of utility-scale solar would remain above 5 cents per kWh through 2050, a barrier that has already been broken, with global and US solar costs (unsubsidized) already below 5 cents per kWh by 2020.

Figure 1: Comparison of solar costs to solar price forecasts



Source: Ramez Naam, "Solar's Future is Insanely Cheap (2020)" (May 2020), https://rameznaam.com/2020/05/14/solars-future-is-insanely-cheap-2020/.

[28] Rocky Mountain Institute, *A Low-Cost Energy Future for Western Cooperatives* (August 2018), p. 5.

The rapidly evolving cost of some technologies, notably solar, wind, and battery storage means that the very foundation of Duke Energy's IRP evaluation is a matter of technology speculation.

In hindsight, technology analysts have shown that clean energy resource costs follow a very "predictable" cost curve. As discussed above, solar costs have declined well below virtually all market price forecasts. So while costs trends were not predicted in key forecasts, the data may now exist to predict these costs.

One technology analysis organization, RethinkX, has published a particularly striking analysis of cost trends for these technologies:

> Cost improvements in solar PV, onshore wind power, and lithium-ion battery technologies have been consistent and predictable for over two decades. Moreover, for solar PV and lithium-ion batteries these improvements have been nothing short of spectacular. The combination of incremental improvements in the underlying technology together with scaling of manufacturing creates a strong correlation between unit cost and production volume, as is common across technologies of many kinds. Solar PV, onshore wind power, and lithium-ion batteries are thus each tracing their own experience curve.[29]

The "experience curve" described by RethinkX is commonly known as a learning rate, and such correlations have been demonstrated in a wide range of industries. Typically, learning rates demonstrate a correlation between production volume and cost that appears as a logarithmic plot over time.

Notwithstanding this economic tendency, future costs trends will depend on factors that cannot be known with precision. As demonstrated by the history of nuclear power development, production experience is no guarantee of declining costs. Government policy, global demand, resource shortages, and a host of other factors can influence prices and, in turn, production volumes over time.

RethinkX's derivation of the learning rates for solar PV and battery storage are shown in **Figure 2**. From 2020 to 2030, RethinkX projects a further 72% decrease in solar PV costs and an 80% decrease in battery storage costs.[30]

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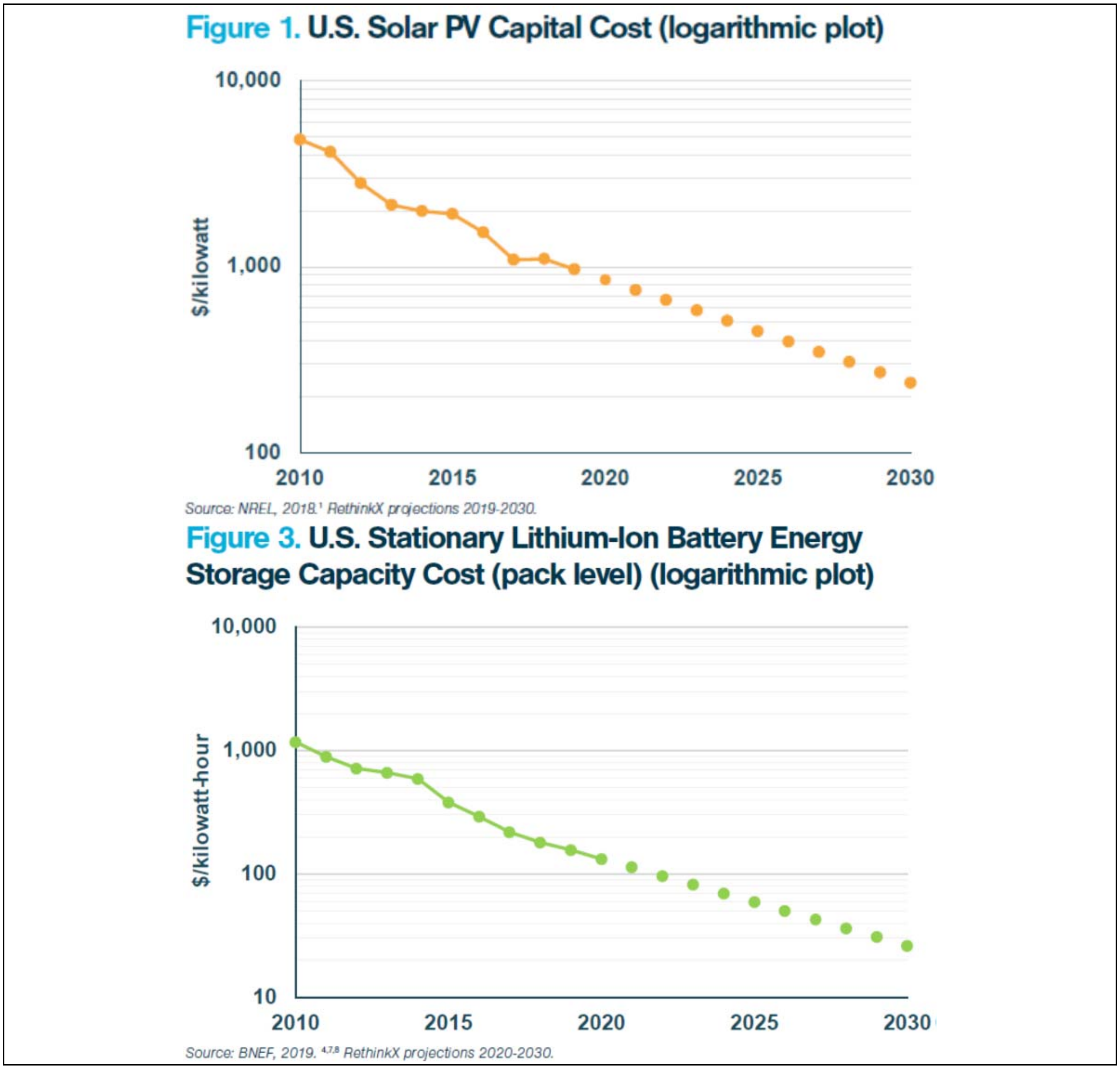
[29] Adam Dorr and Tony Seba, *Rethinking Energy 2020-2030*, RethinkX (October 2020), p. 15. (Hereafter, "RethinkX")

[30] RethinkX, p. 8.

Figure 2: RethinkX Forecast of Solar and Battery Storage Costs



RethinkX, p. 15.

In comparison to RethinkX's striking forecast of steadily declining clean energy prices, Duke Energy's forecast anticipates more gradual changes, as shown in **Table 1**. If the cost reductions are similar to the RethinkX forecast, 2030 costs for the listed resource types would be 40% to 64% of Duke's projections.

Table 1: Duke Energy and RethinkX Forecast Costs, 2020–2030

	Cost Change, 2020–2030		Ratio of 2030 Cost
	RethinkX	Duke Energy	RethinkX ÷ Duke
	a	*b*	*c*
Solar	- 72%	- 42%	**48%**
Wind	- 43%	- 11%	**64%**
Batteries	- 80%	- 50%	**40%**

Notes:

a. RethinkX, p. 8
b. DEC and DEP, Chs. 1 & 6, pp. 24, 46; confirmed by Confidential Response to NC Public Staff Data Request 17-1.
c. (1 + a) ÷ (1 + b)

This report does not take a position on whether RethinkX or Duke Energy's forecasts are correct, or that one is better than the other. The challenge of validating cost forecasts are illustrated by Duke Energy's statement that market pricing can differ so much from IRP cost forecasts that a comparison "yields little value in planning space."[31] Duke Energy provides several examples of opportunities that may be available in the marketplace, but are not appropriate for planning purposes, including:

- "Market participants will have varying views on the 'terminal value' of a resource after the [fixed finite term of the] contract period which will affect the bid price . .. Conversely, an IRP evaluates technologies over the life of the asset …"
- "For example, an existing large natural gas generator may have sold the majority of its output under a long-term contract allowing it to bid its remaining capacity into a short-term capacity RFP at a discounted price that is not representative [of] a market based price …"
- "An individual solar project may have unique circumstances such as local property tax discounts, unique tax equity partners, stockpiled panels, or other unique supply chain arrangements that may not represent a widely available price appropriate for planning purposes."[32]

Whether due to an erroneous forecast of market prices or to the cumulative effect of advantageous pricing due to "unique circumstances," when Duke Energy's "planning space" fails to represent the marketplace, its IRP forecast of capacity needs will inefficiently blend technologies. Such inefficiencies ultimately drive up costs for Duke Energy's customers.

While costs forecasts are necessary in the IRP in advance of the procurement process, the ASP Report's case studies illustrate how utilities who leverage market pricing data throughout the planning and procurement process benefit by:

[31] Duke Energy, response to SELC DR-8-1(d).
[32] Duke Energy, response to SELC DR-8-1(d).

- Obtaining price and performance information about generation alternatives directly from the marketplace. The PNM all-source procurement received 735 bids – developers are clearly willing to participate in highly competitive procurement.
- Identifying unanticipated opportunities to meet electricity supply challenges more efficiently with a blend of technologies. Xcel Colorado needed to replace 660 MW of coal plants, but was offered over 58,000 MW (nameplate) of generation resources and procured 2,458 MW, representing 1,100 MW of firm capacity.[33]

Lifting the constraints of the utility's own cost assumptions and capacity requirements is a reasonable and prudent approach. It will result in procurements that will more closely reflect the least cost mix of options.

Constraints on capacity requirements arise from the conventional need determination, which relies on the utility's internal cost forecasts. Typically, utilities obtain cost forecasts from vendor relationships and prior self-build experience, which may be outdated or omit information from competitive market suppliers. Relying on internal cost forecasts and then conducting a series of single-technology need determinations with numeric capacity targets would put Duke Energy, or any vertically integrated utility, on a path that is constrained by those forecasts.

Thus, need determinations, which initiate any RFP process, are sensitive to the generation cost forecasts. If battery prices decline by 80%, rather than 50%, Duke Energy's plans for resource procurement will be outdated and misaligned in terms of cost, schedule and price – likely resulting in procuring the "wrong" resources. These problems can be mitigated by obtaining market-based pricing at the exact time that it is needed for evaluation and contract negotiation by Duke Energy, or any other vertically integrated utility. To minimize the impact of generation cost forecasts on the RFP, the ASP Report recommends what this report is referring to as a ***load+retirement*** approach to need determination.

[33] ASP Report, p. 33.

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

8-2. RE: Response to Vote Solar 2-31

c. Please identify all practices that DEC or DEP follow when conducting a competitive solicitation. Please note in your response whether those practices have only been followed for the CPRE solicitations, or whether they are followed for all solicitations. For each practice the Companies follow, please also note whether the Companies would obtain pre-approval by either (or both) Commissions or Commission staff, or whether the Companies would submit the practice for review during the resource Certification process. In your response, please consider the following examples of practices, providing a complete list of practices followed by one or both of the Companies.

i. Bid evaluation using comparison of:

1. Prices, without adjustment for other benefits/costs

2. Net pricing, with spreadsheet adjustment for other benefits/costs

3. Modeled net benefits, using capacity, production cost, or resource adequacy models to identify optimal resource(s)

ii. Consideration of interconnection costs

iii. Valuation of ancillary services

iv. Joint evaluation by DEC and DEP of bid results

v. Disclosure of information to bidders such as geographic preferences due to load, transmission capability, etc.

vi. Disclosure of final PPA with all terms and conditions pre-approved by the NCUC or SCPSC (please provide details of the pre-approval process)

vii. Consideration of non-quantitative factors such as viability/experience, permitting issues, etc.

viii. Development of multiple portfolios for final review, if such a practice has been utilized, please identify who conducted the final review of the portfolios (Company staff, executives, Commission staff, Commission, etc.)

ix. Procedures to ensure that the Company or its affiliates compete fairly with other bidders

x. Use of independent evaluator, administrator, etc. (please identify roles)

Response:

The following identifies the practices generally used by Duke Energy to conduct competitive solicitations. The specific practices for each competitive solicitation may vary due to the exact objectives and requirements from regulatory or legislative actions. NC HB 589 requires that the NC CPRE solicitations, including the analysis of the bids and selection of winning bids, are performed independently by a third-party consultant. The Companies have attached to this response the Independent Administrator's Final Report from Tranche 1, which provides an explanation of the analysis performed by Accion. Generally, most regulated utility competitive solicitations follow the same high-level practices (including the NC CPRE solicitation) but can vary in the analysis of bids due to the level of sophistication in methodology selected by the utility or outside consultant. Unless required by statute or by the respective Commission (NCUC or SCPSC), the Companies do not obtain pre-approval by either utility commission for the issuance of the RFP.

CPRE IA - Final
Report Tranche 1.pdf

Duke Energy RFP Process

RFP Design

- Recognize the resource need and specific requirements for an RFP as directed from the filed Integrated Resource Plan.
- Determine applicable resource types including traditional, renewable, and/or Distributed Energy Resource (storage) generation resources, the need for peaking vs. baseload operations, and dispatchable vs. non-dispatchable requirements.
- Determine applicable RFP contract structures including but not limited to Purchase Power Agreements ("PPA"), Build-Own-Transfer arrangements ("BOT") and existing Asset Purchases ("AP").
- Determine applicable delivery points including preferred locations (Balancing Areas), transmission firmness/interconnection requirements and general deliverability requirements.
- Determine applicable quantitative and qualitative bid characteristics (with relative importance) that will be considered during project analysis and selection.
- Determine targeted RFP participants including considerations of affiliates that may require an independent third party to oversee the RFP process.
- Create RFP solicitation and term sheets including applicable IRP, resource, and contract specifications with a primary goal of clearly defining the product being requested. The RFP document should provide an overall transparent description of analysis methodology, timelines, bidder response requirements, and all value metrics to be considered.
- Review RFP as appropriate with stakeholders.
- Release RFP to marketplace with specific dates for notice of intent to bid (NOIB), RFP milestone schedule, and proposal submission details.

RFP Analysis

- Receive proposals using applicable confidential/firewall separations as appropriate with regulators and utility standards.

- Review submitted proposals for compliance with RFP specifications

a. **Dispatchable Proposal Analysis**

i. Perform initial static cost screening

1. Fuel commodity and transportation costs are developed.
2. Assume capacity factor and starts based on production cost modeling experience to determine all operational energy costs.
3. Determine all applicable costs including wheeling, interconnection, capacity, fixed and variable O&M, fuel.
4. Summarize all calculated costs and rank proposals using annual levelized $/kw costs
5. Identify most cost-effective proposals from screening to proceed forward to more detailed production costing modeling

ii. Perform more detailed production costing modeling for highest ranked proposals.

1. All operational proposal characteristics modeled in detailed production simulation energy models.
2. Calculated model energy values netted against fixed costs (Wheeling, FT, Capacity Fees, FOM) to determine net levelized $/kw annual cost
3. Rank proposals on a net levelized $/kw cost basis.
4. Quantitative and qualitative results for each proposal are summed and ranked for short list proposal selection
5. Highest ranked bids modeled in alternative portfolios and scenarios (using ranges of fuel costs, loads, and environmental costs) to determine most robust portfolio selections.
6. Short listed proposals identified, and contractual negotiations are initiated.

b. **Non-Dispatchable Proposal Analysis**

1. Transmission wheeling charges determined and added to proposal cost.
2. Non-dispatchable hourly generation profiles are used to develop energy benefits using hourly power market curves and/or marginal/avoided hourly costs.
3. Capacity benefits are calculated using non-dispatchable hourly energy profiles consistent with utility capacity needs.
4. REC benefits are given when appropriate.
5. Benefits (energy, capacity, ancillary) are netted against costs (wheeling, interconnection, fixed, ancillary) to develop annual “net costs” for bid term/project life.
6. Net costs are levelized on a $/mwh basis and ranked for comparison.
7. Quantitative and qualitative results for each proposal summed and ranked for short list proposal selection.
8. Most cost-effective bids modeled in alternative proposal portfolios and scenarios to determine most robust proposal selections.
9. Short listed proposals commence contractual negotiations.