DUKE ENERGY

Winter Peak Analysis and Solution Set

December 2020

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Table of Contents

Table of Tables

Table of Figures

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

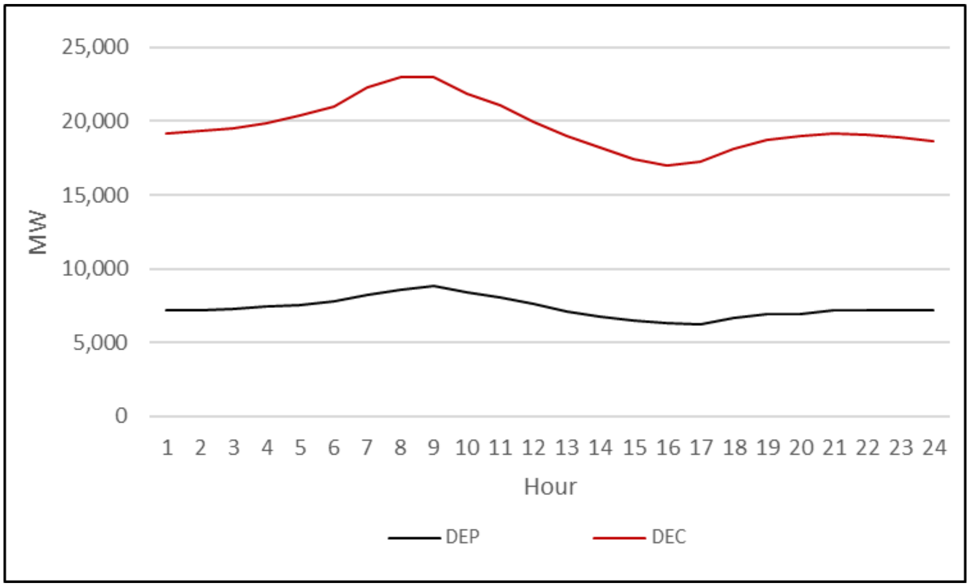


Figure 2 shows the aggregated DEC and DEP load profiles for the residential, small and medium C&I, and large C&I market sectors for the study peak day. The load profiles are overlaid on one another to illustrate the relative magnitude of each market segment indicating that the residential winter morning 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

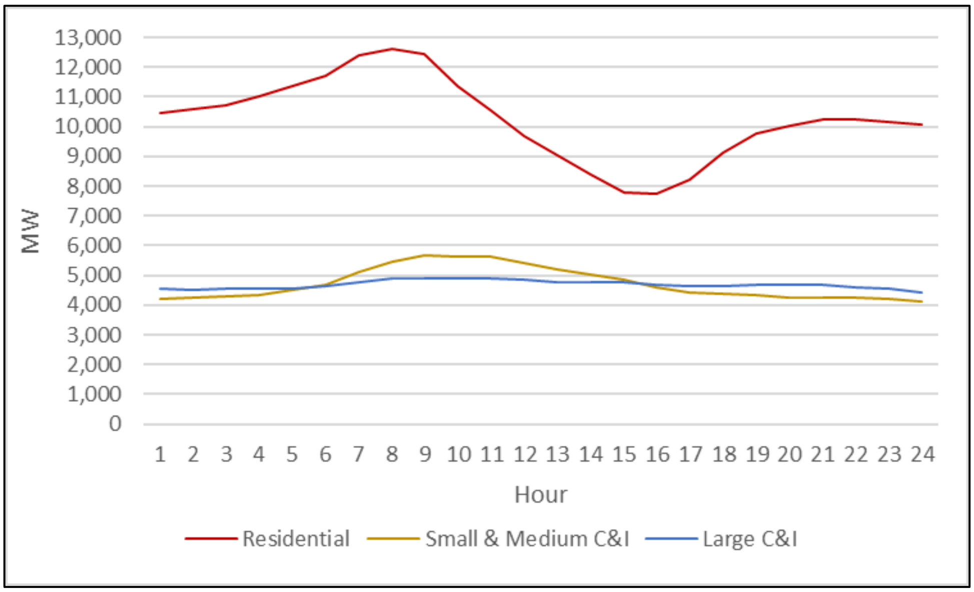
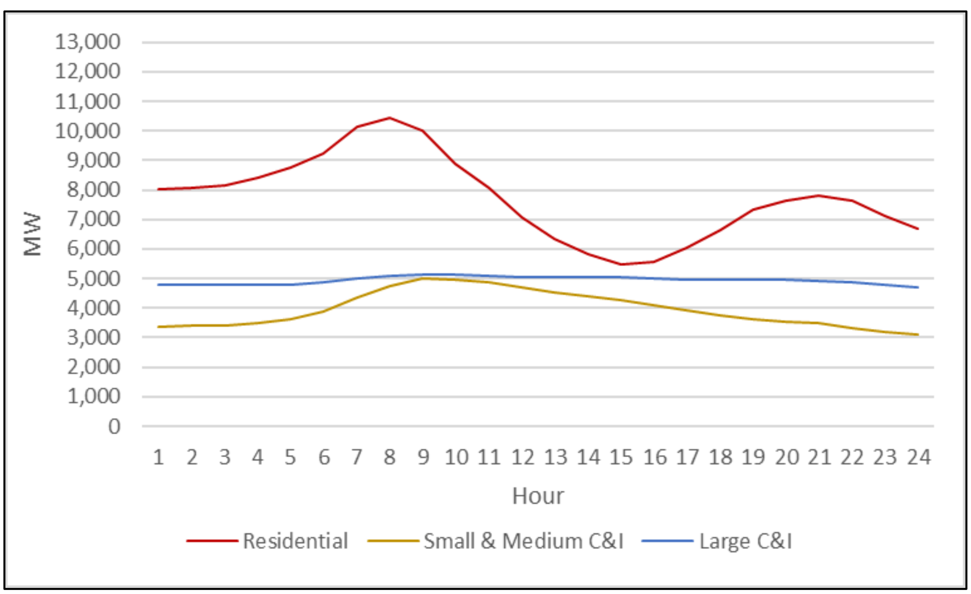


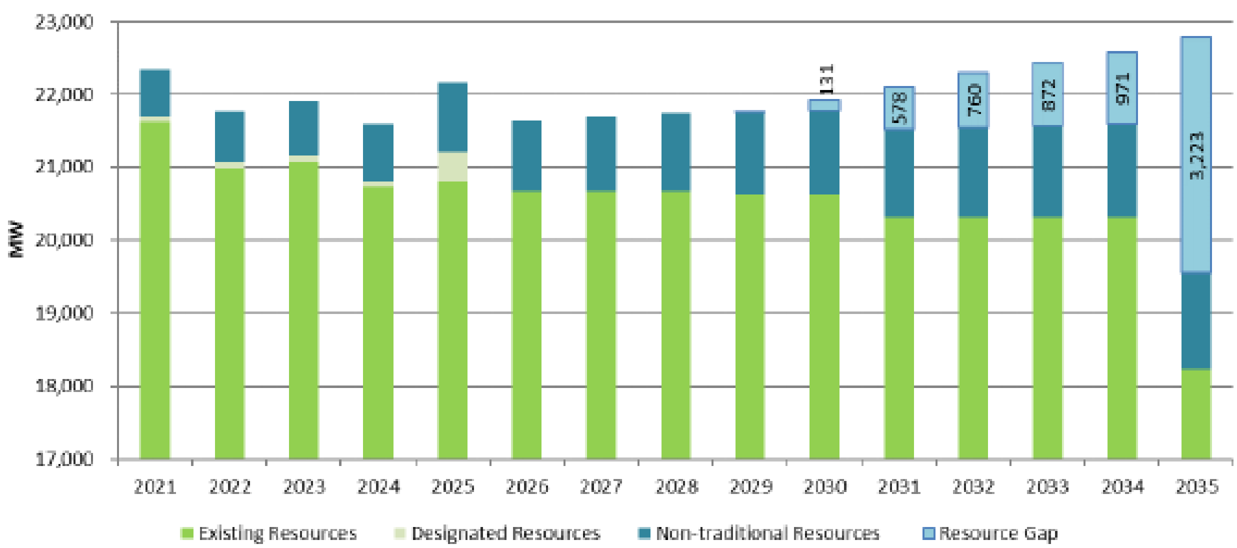
Figure 3. Overlay of Demand Profile by Market Segment - Average Winter Peak Day



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

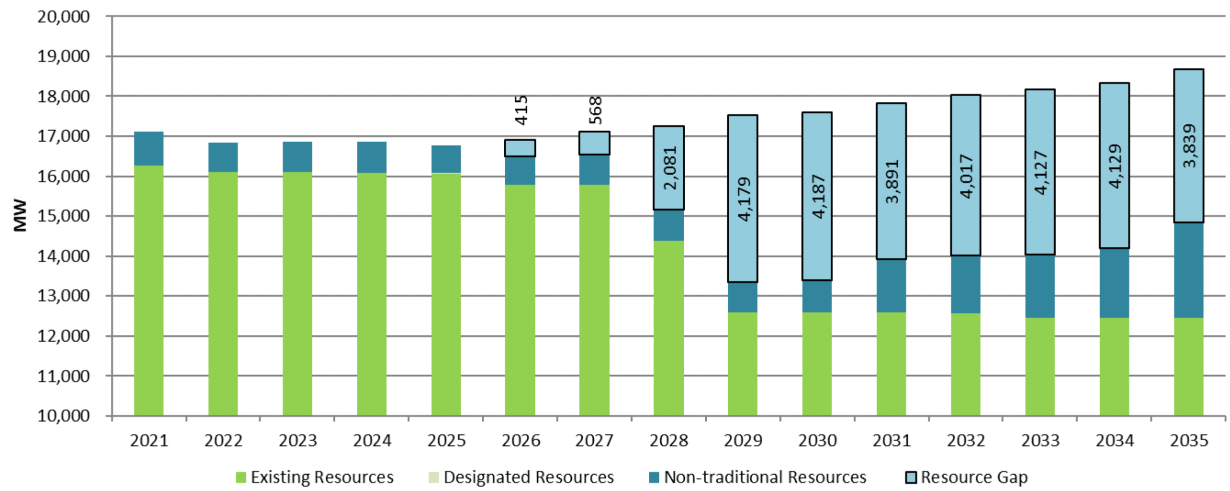
[5] Duke Energy Progress 2020 Integrated Resource Plan. Table 5-A. DEP Base with Carbon Policy Total Renewables

[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

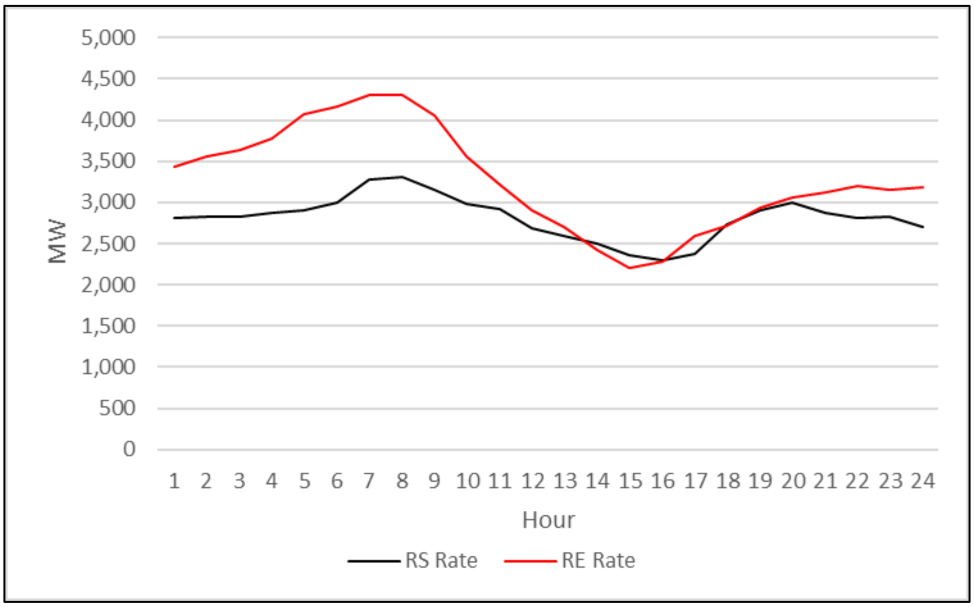
[11] For example, the MPS forecasts the industrial sector to decrease by 6% in NC and 11% in SC by 2044.

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

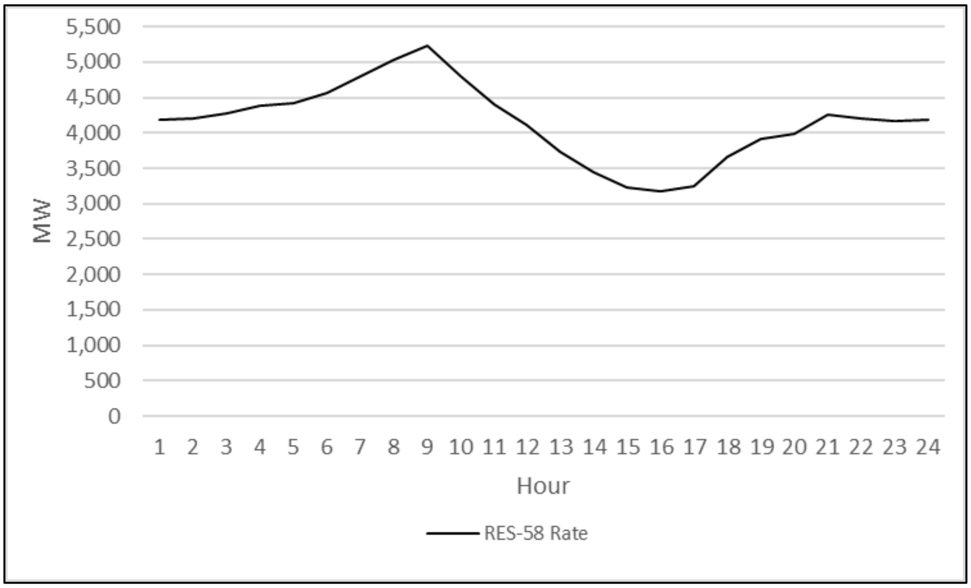
We analyzed various residential market characteristics, appliance saturation data, rates and load profiles for the residential market and concur with past conclusions that the residential winter morning peak demand is driven primarily by electric space heating, with some contribution for electric water 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

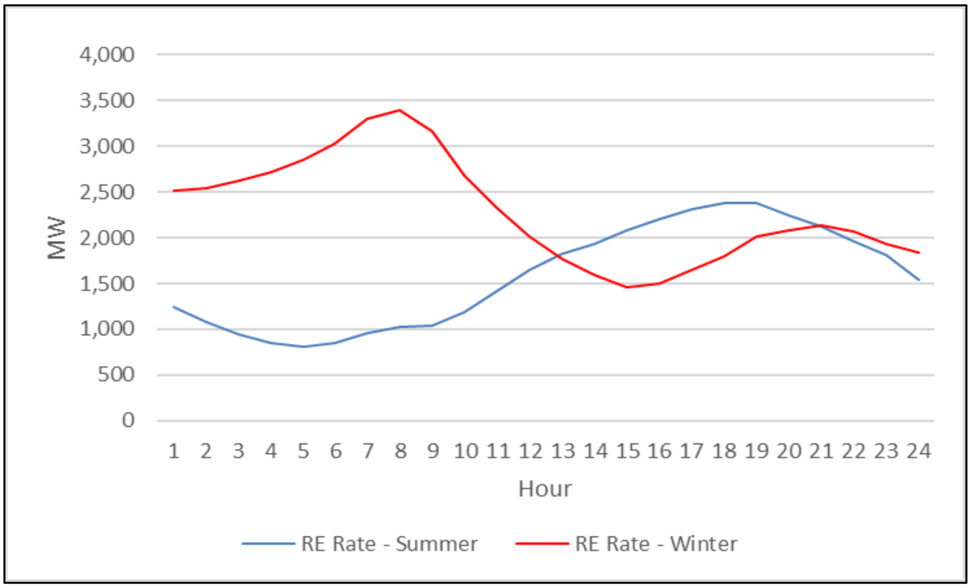


To gain a sense of the magnitude of the electric heating load and types space heating systems that drive peak demand, we also looked at the DEC all-electric 'RE' rate during summer and winter peaks, as presented in Figure 6 showing a difference between summer and winter average peak of 2,500 MW. Because 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

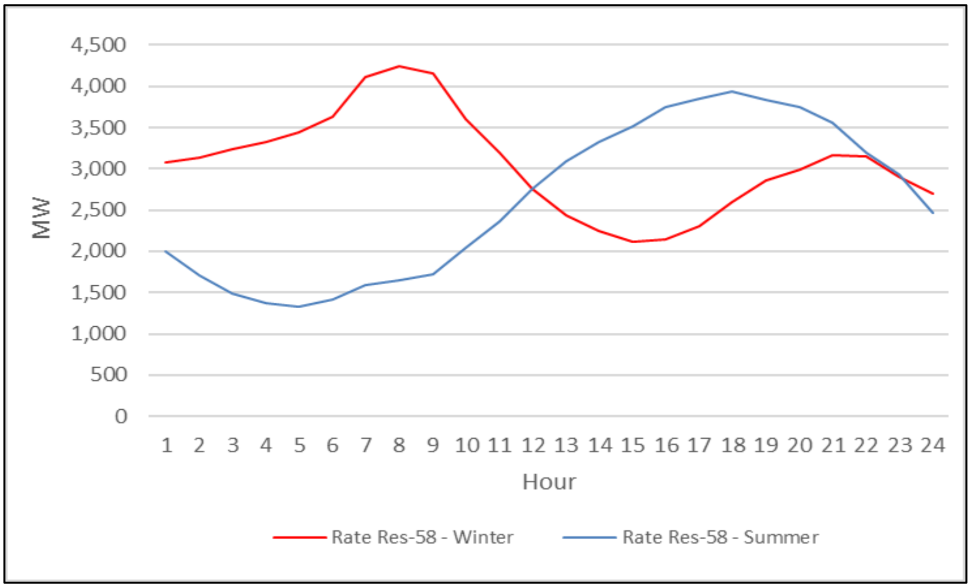
[12] Hot water energy use is generally consistent throughout the year because water usage patterns and groundwater temperature are generally consistent.

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

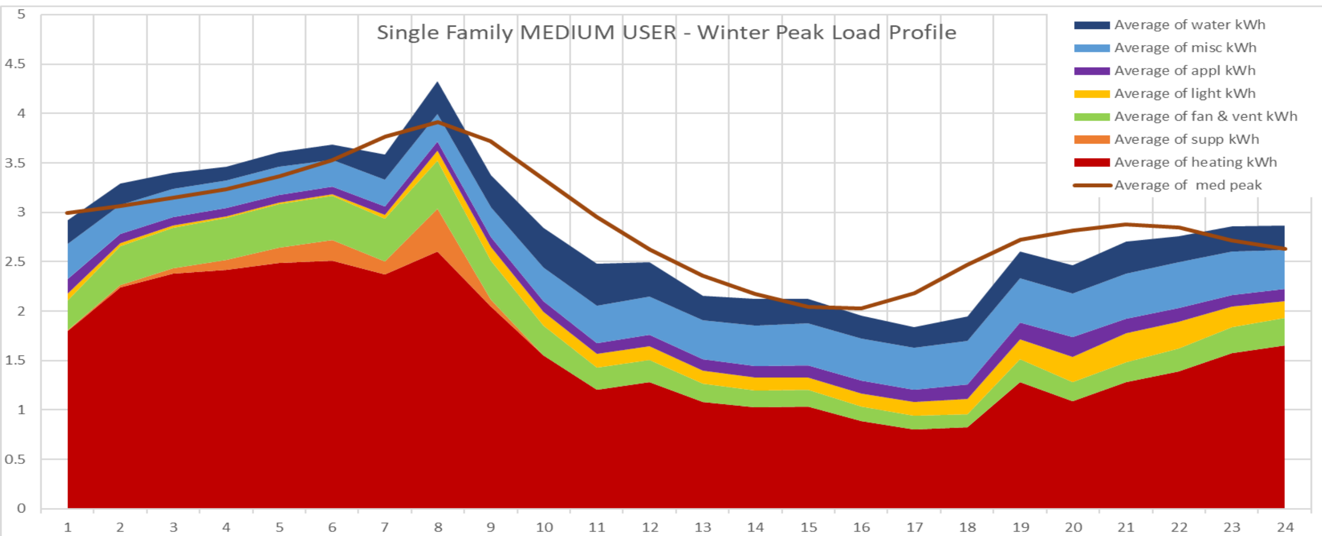
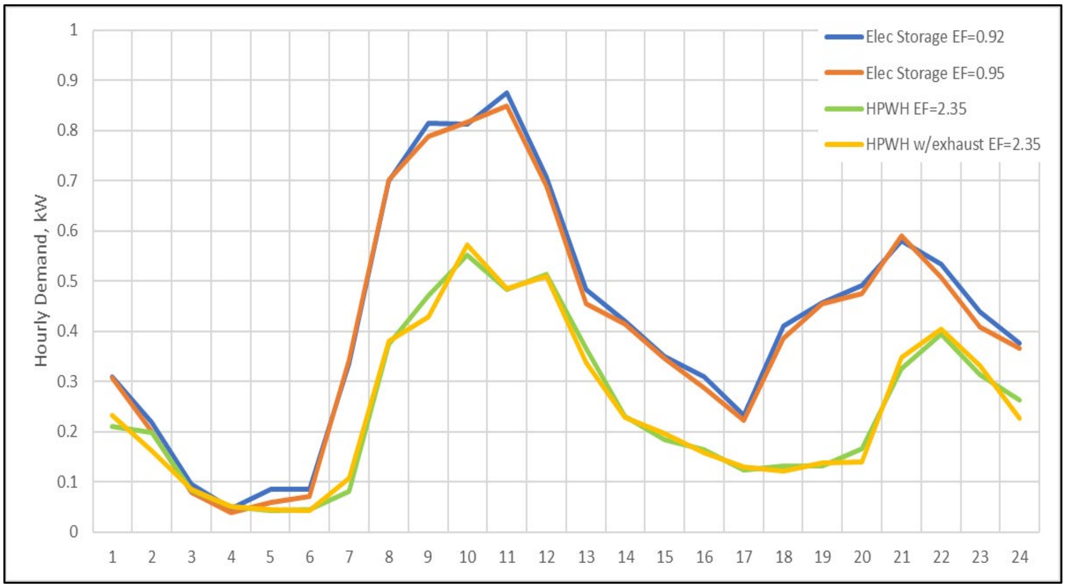


Figure 9 is the modelling output for electric hot water heaters (HWH) showing that electric resistance water heaters require about 0.8 kW per unit during morning peak hours. Duke's 2019 RASS indicates 71% of dwellings use electric HWH, and we estimate this represents about 2.5 million installed resistance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

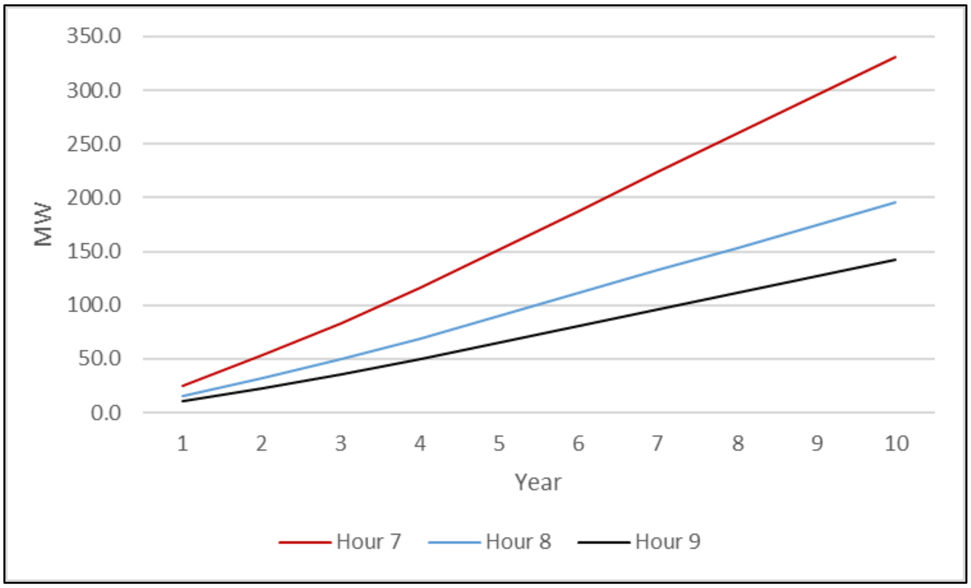
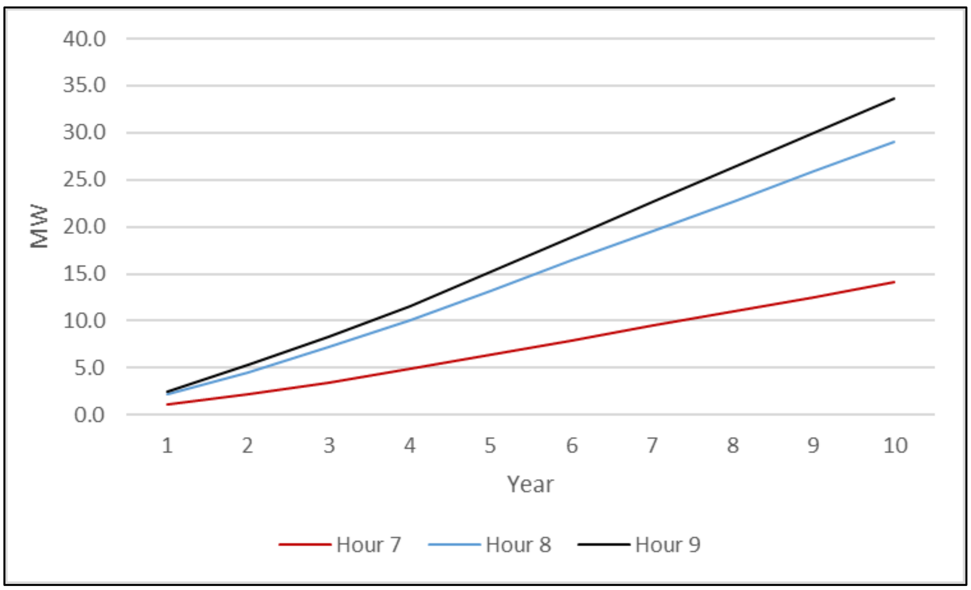


Figure 13. 10-Year Hot Water Heating Savings Forecast by Hour



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

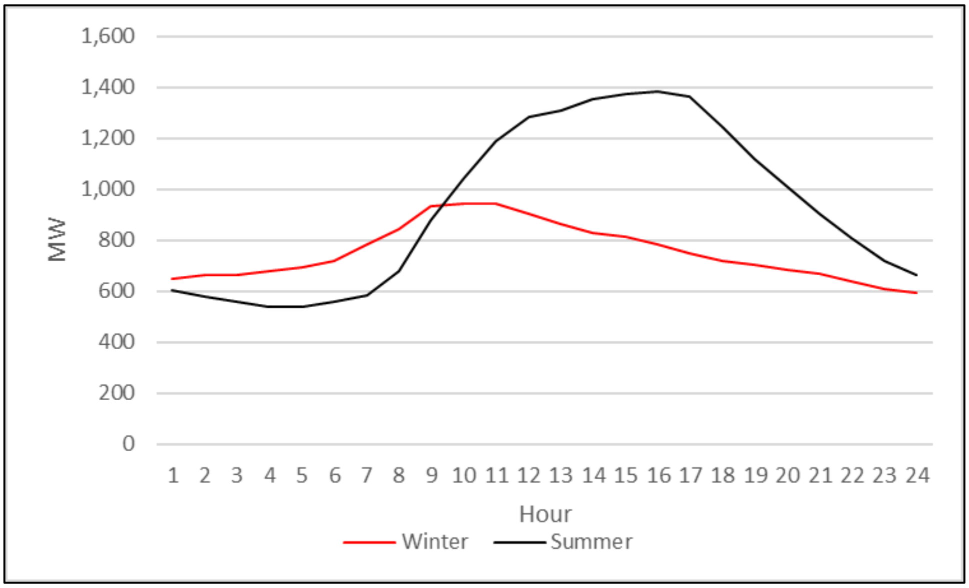
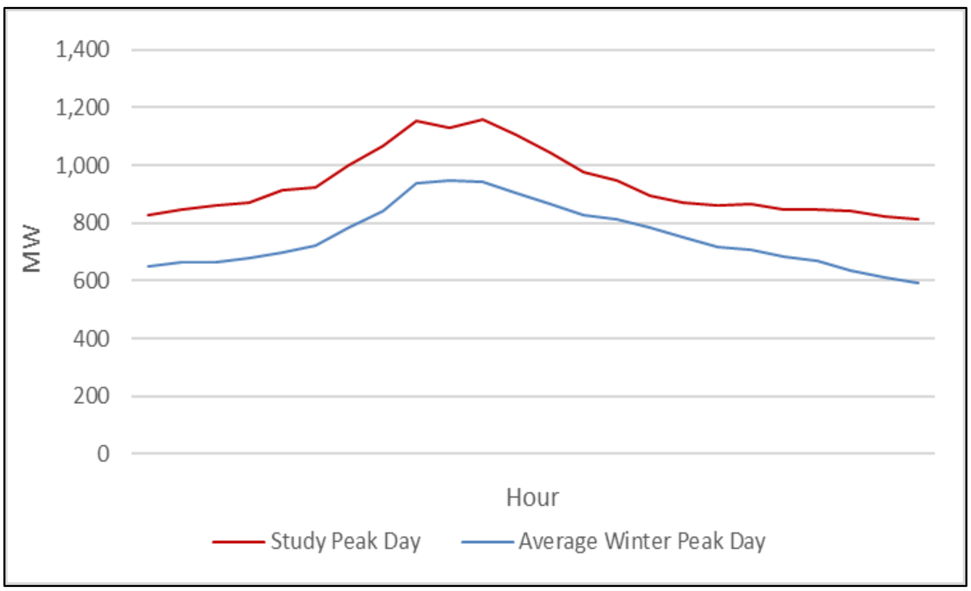


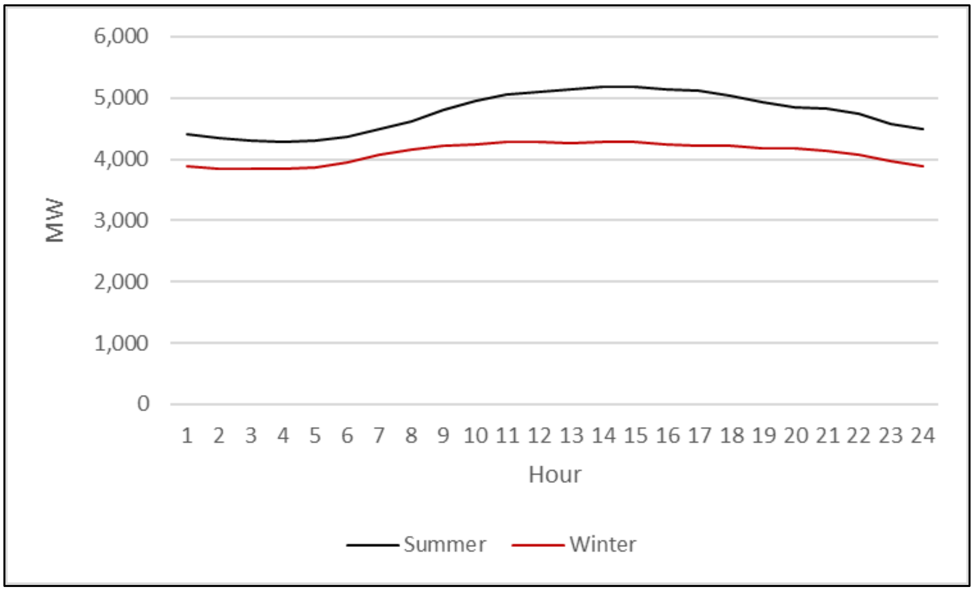
Figure 15. DEC 2018 SGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



Large C&I

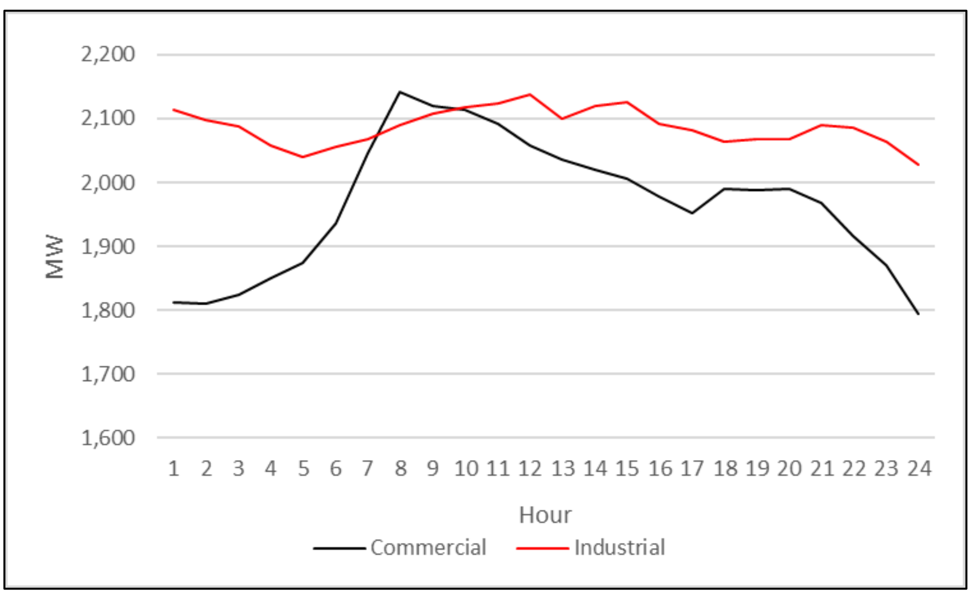
We reviewed the optional TOU rates offered to DEC customers, and the RTP rate offered to DEP customers and Figure 14 shows the demand prolife for the DEC optional C&I TOU rate during the 6 winter and 4 summer events we analyzed. At the aggregate rate level, this profile is generally flat every day, with 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.

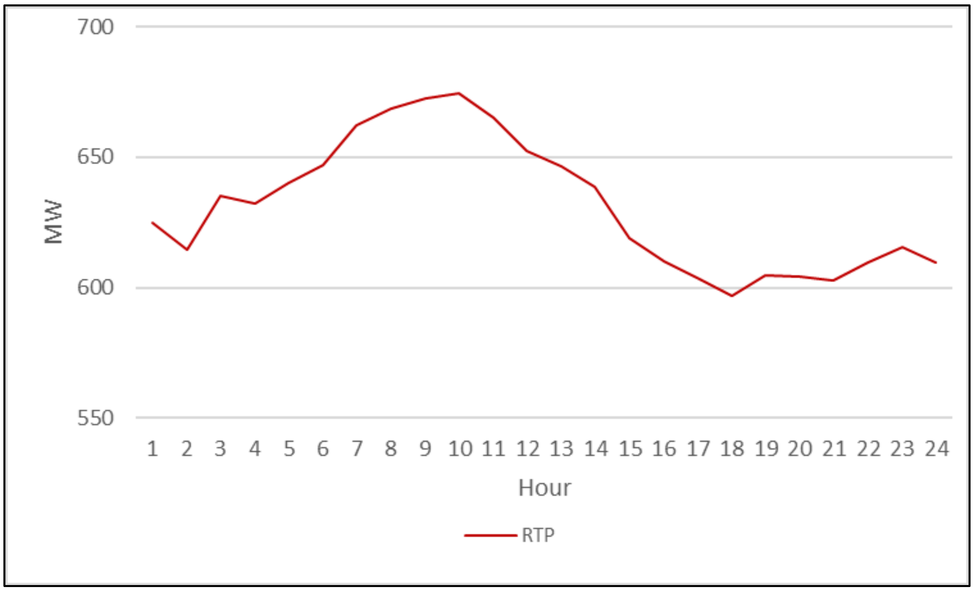
Figure 17. DEC C&I Optional TOU Rate Demand by Segment – Study Peak Day



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

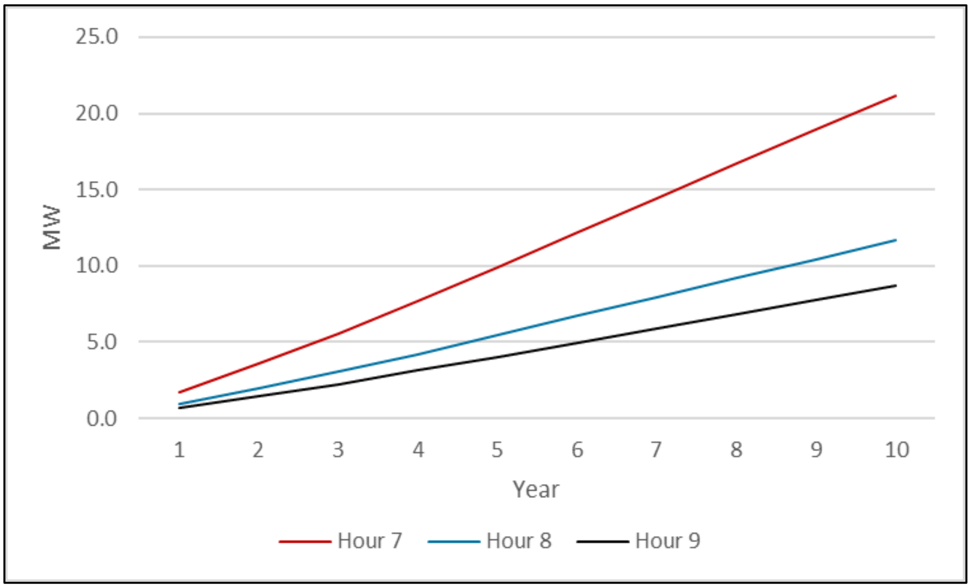


Based on the preceding analysis, the proposed C&I solution set targets demand related to winter morning electric space heating and other building systems and includes the following:

- 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.

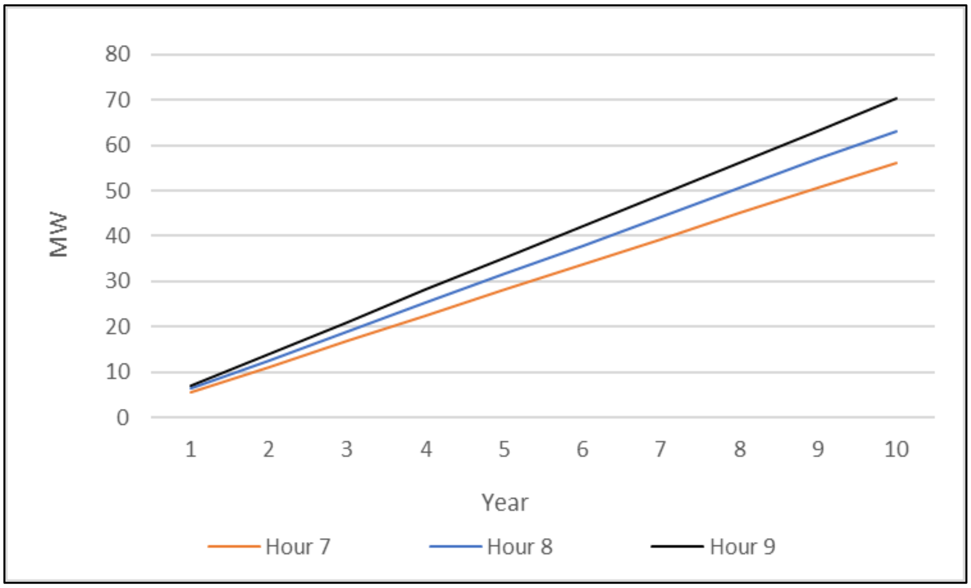
Figure 19. 10-Year Small Commercial Thermostat Solution Savings Forecast by Hour



- 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.

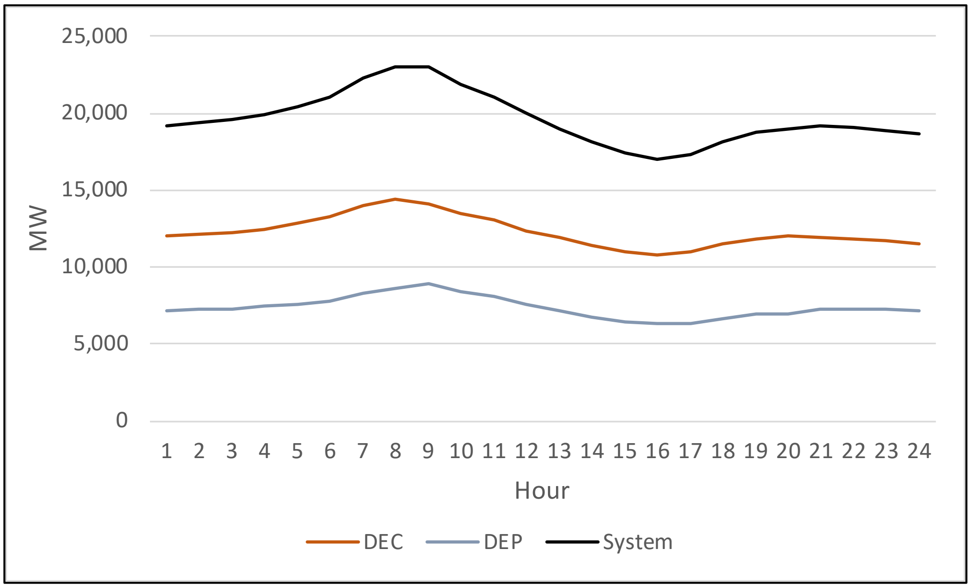
Table 3. 2018 Utility Peak Event by Season

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.

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[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)

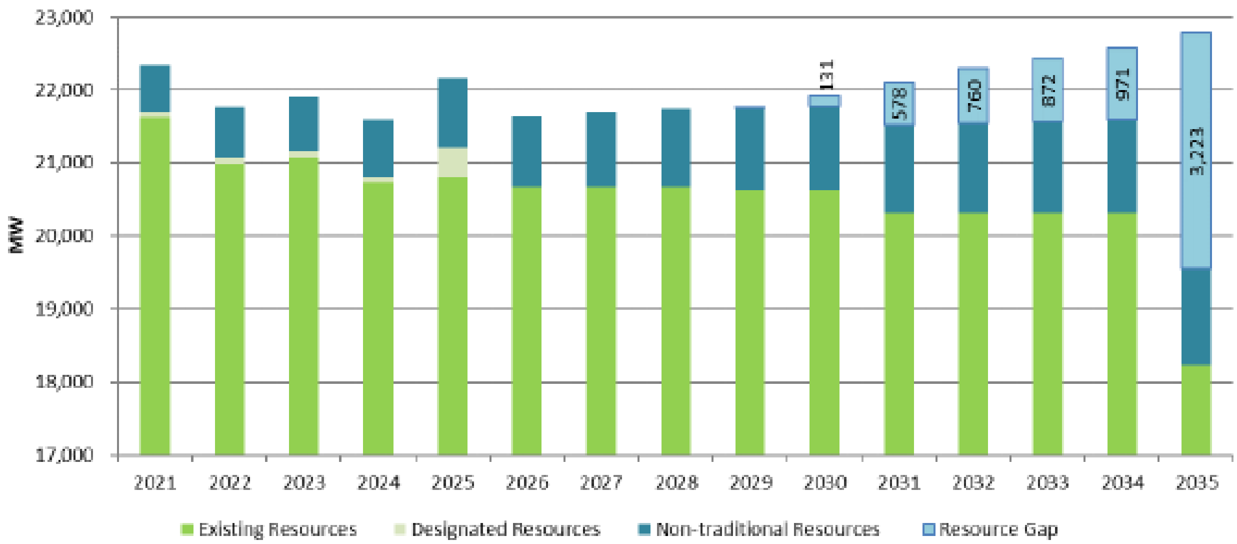


Figure 23. DEP Base Case with Carbon Policy Load Resource Balance (Winter)

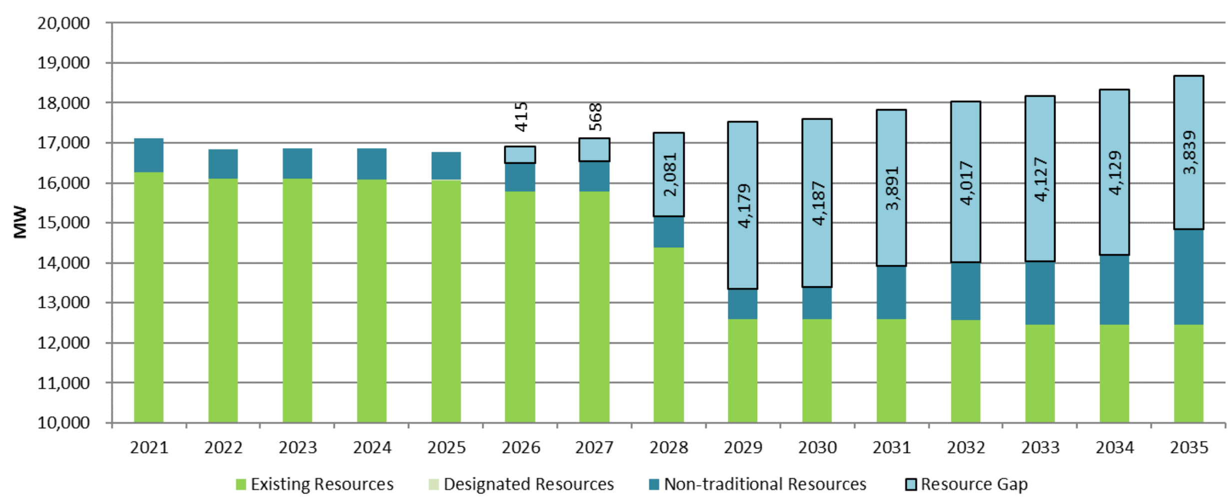


Figure 20 shows demand overlaid individually for each market sector on the study peak day, indicating that residential demand at hour 8 accounted for approximately 12,600 MW (54% of system peak), small to medium C&I sector accounted for 5,600 MW (25% of system), and large C&I accounted for 4,800 MW (21%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

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

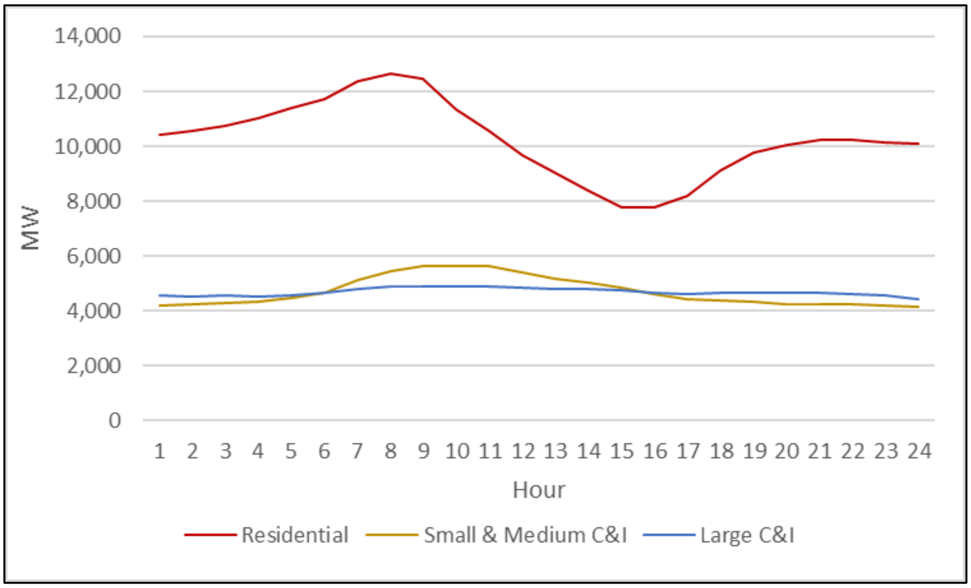


Table 4 shows the 3-hour peak event window for each rate class highlighted in green for the study peak day. This distribution of 3-hour events was common in all peak events reviewed and followed this sequence:

- 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

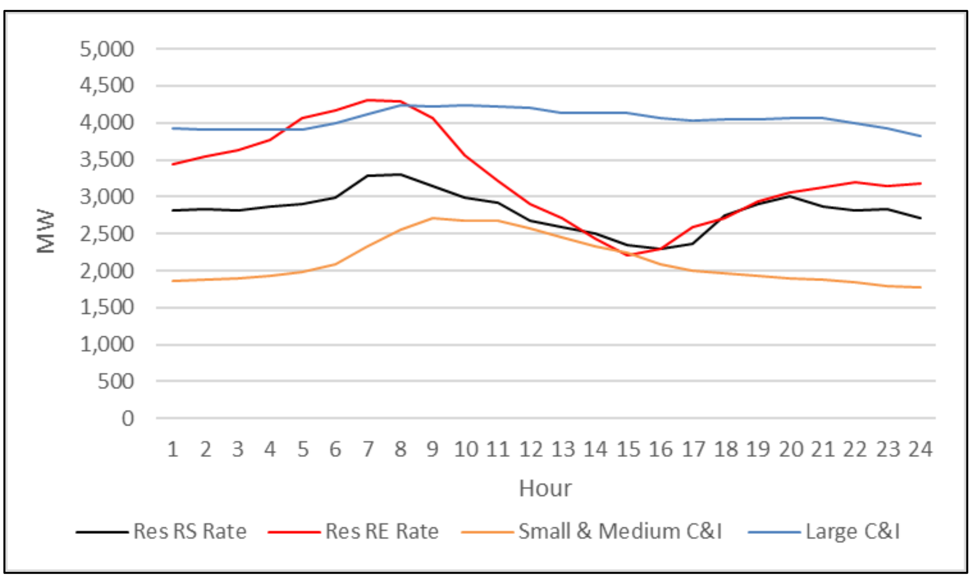


Figure 26. DEC 2018 Peak Demand Profile by Rate Class - Average Winter Day

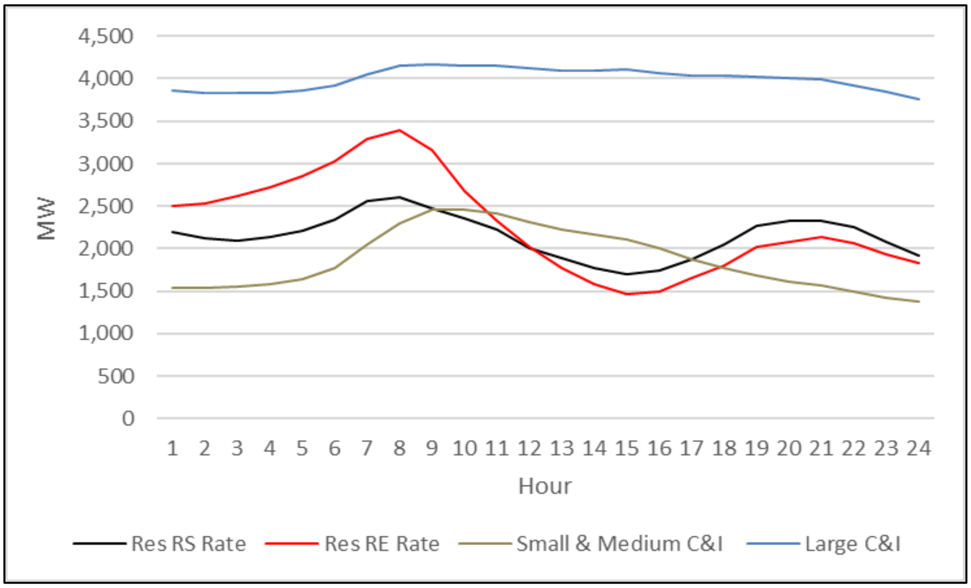


Figure 23 shows the load profile for various DEP rates and rate classes for our study peak day, including:

- 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

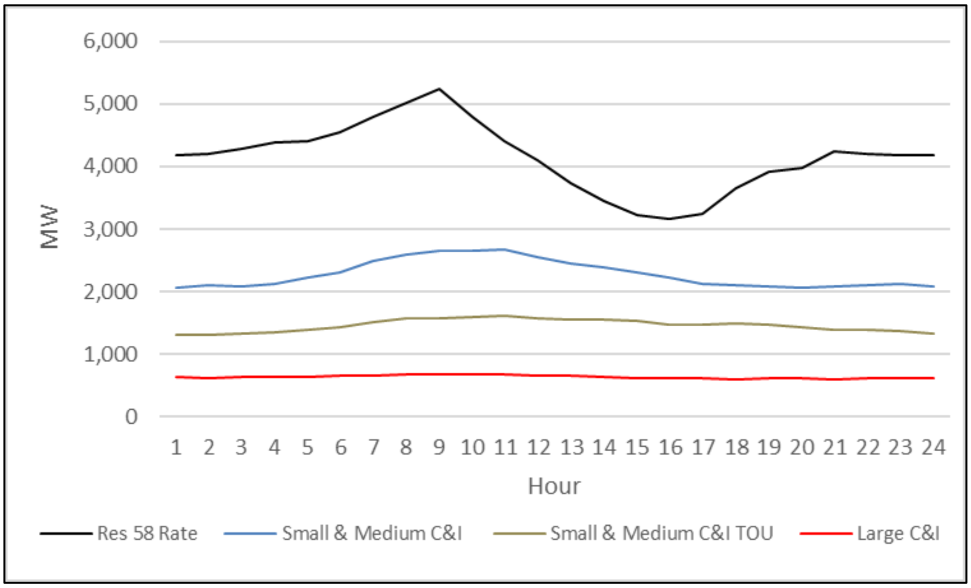
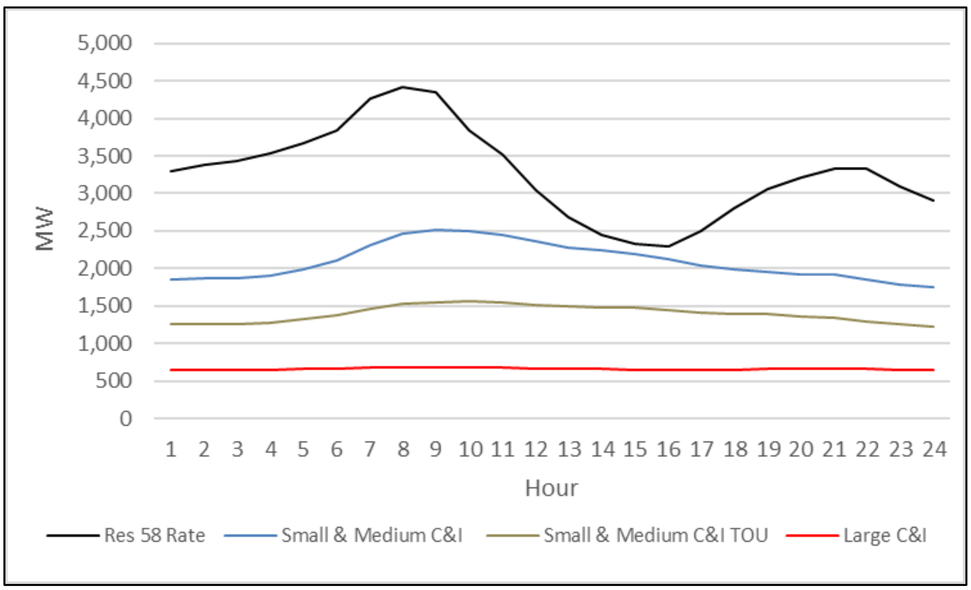


Figure 28. DEP 2018 Demand Profile by Rate Class - Average Winter Peak Day



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

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

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

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

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

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

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

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

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

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

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

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

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

Summary of DSM Rider Opt-out

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

Table 16. DEP Opt-out by Rate Class

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

Table 17. Summary of Opt-out by Utility

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

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

4. Residential Market and Solutions

Rate Definitions

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

Table 18. Residential Rates Summary

<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

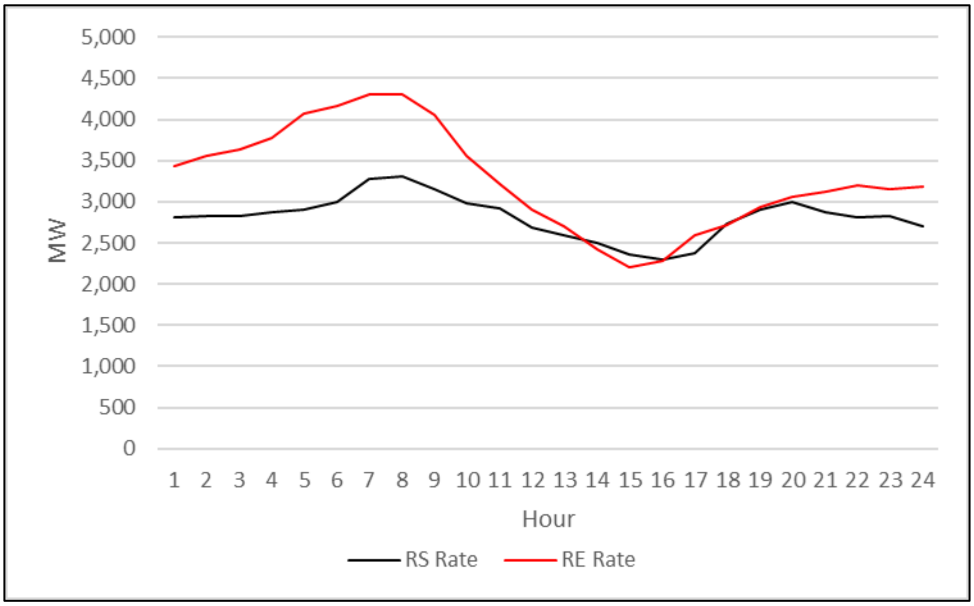


Figure 26 is the average of six winter peak days in 2018 for the RS and RE rates and shows the same profile as Figure 25, though the average morning and evening peaks are lower for each rate than the study peak day. The difference between study peak day and average winter peak day is about 900 MW, or 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

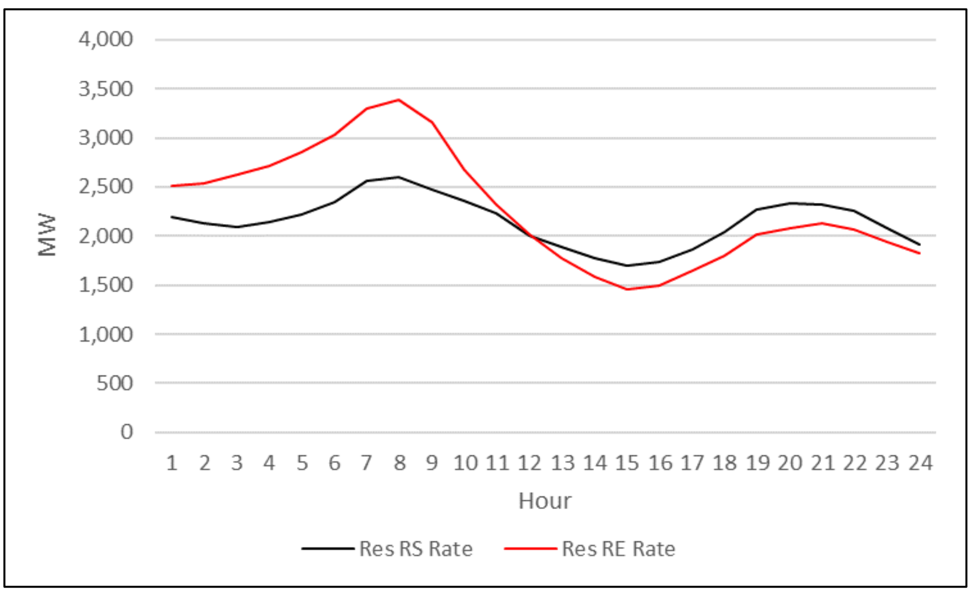


Figure 27 compares the TOU rate, RT, to the RT and RS rates, showing the average winter peak day demand profile over a 24-hour period for all three rates. We observe that the RT rate profile more closely aligns with the RE rate, with some slight shifts, but participation in the RT rate is very small 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

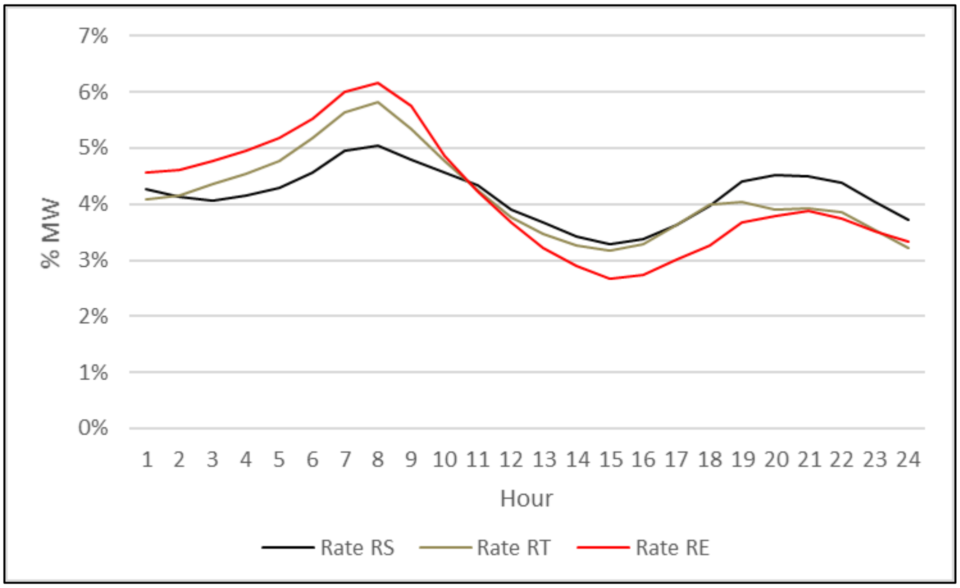


Figure 28 compares the average winter and summer peak for the RE rate for the 6 winter and 4 summer peak days previously defined at Table 3. On average, winter peak exceeds summer peak by about 1,000 MW. Because household appliances and hot water usage is generally consistent throughout the year, we 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

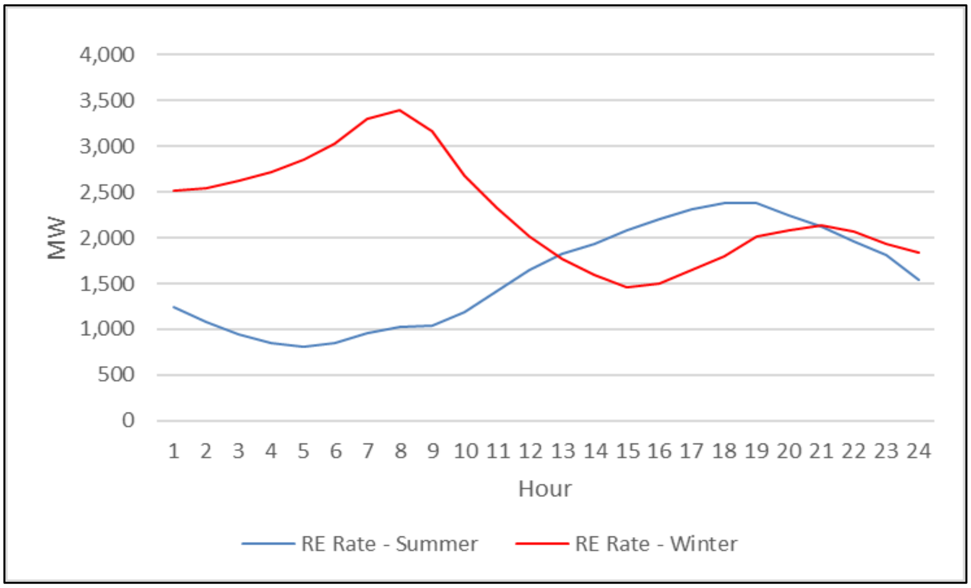
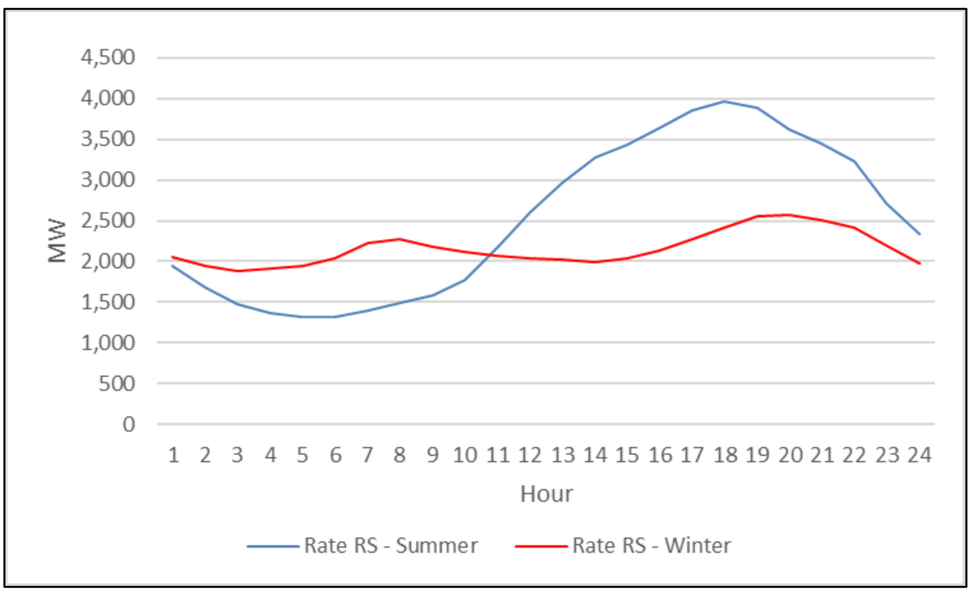


Figure 29 ccompares winter and summer peak for the RS rate for these same 6 winter and 4 summer peak days illustrating the considerable summer evening peak associated with AC demand. We expect that any thermostat solution targeted at winter peak will have benefits for summer AC demand.

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

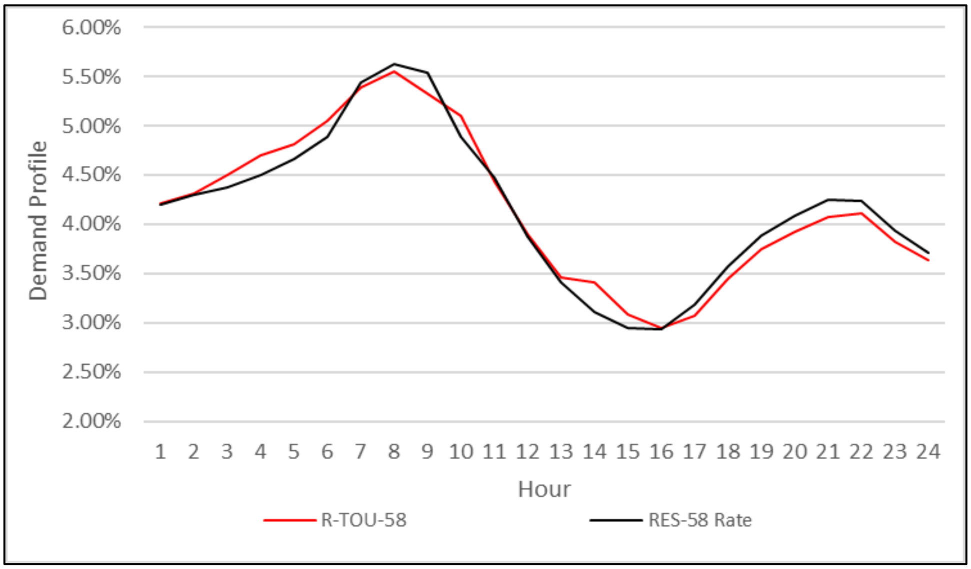
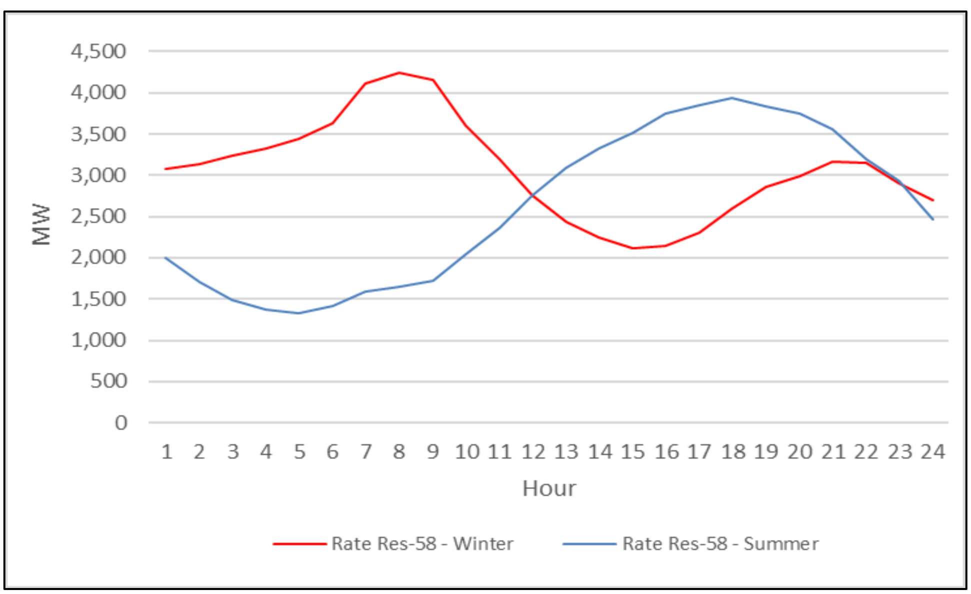


Figure 31 compares average winter and summer peak for the DEP R-TOU-58, and we do see a slight increase in R-TOU-58 average winter peak demand compared to summer, likely because this rate blends homes heated with electric heat and natural gas. Based on the demand differential observed between the DEC 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

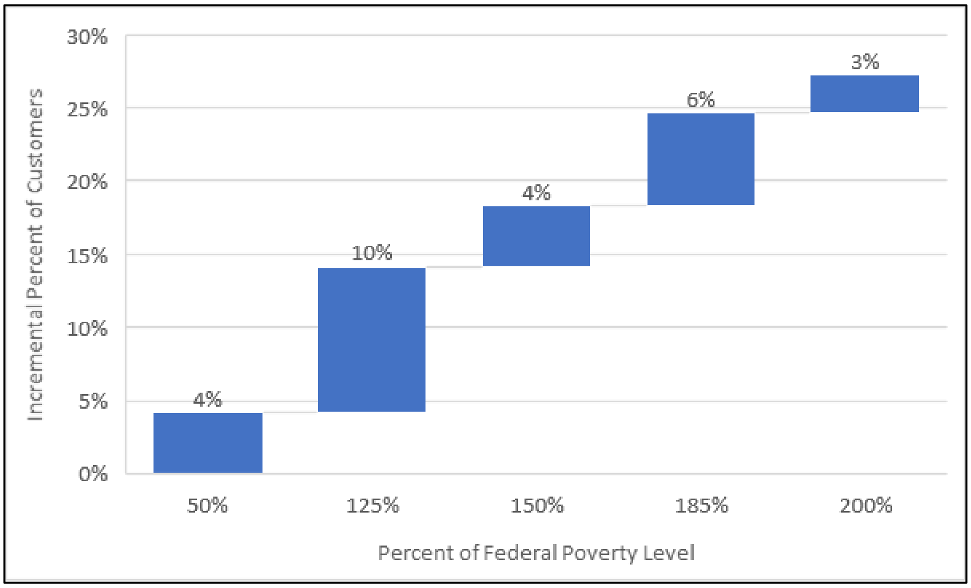
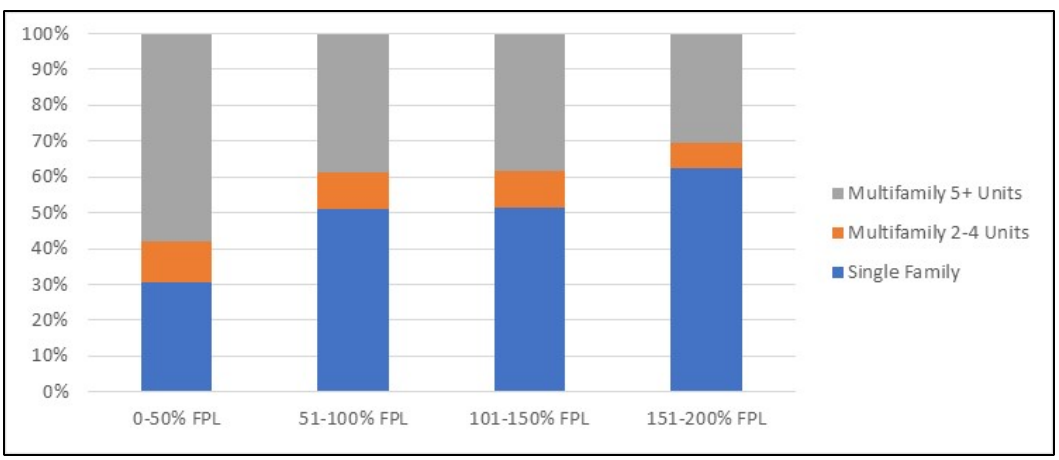


Figure 37. Residential Dwelling Types by FPL Income Cohort



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

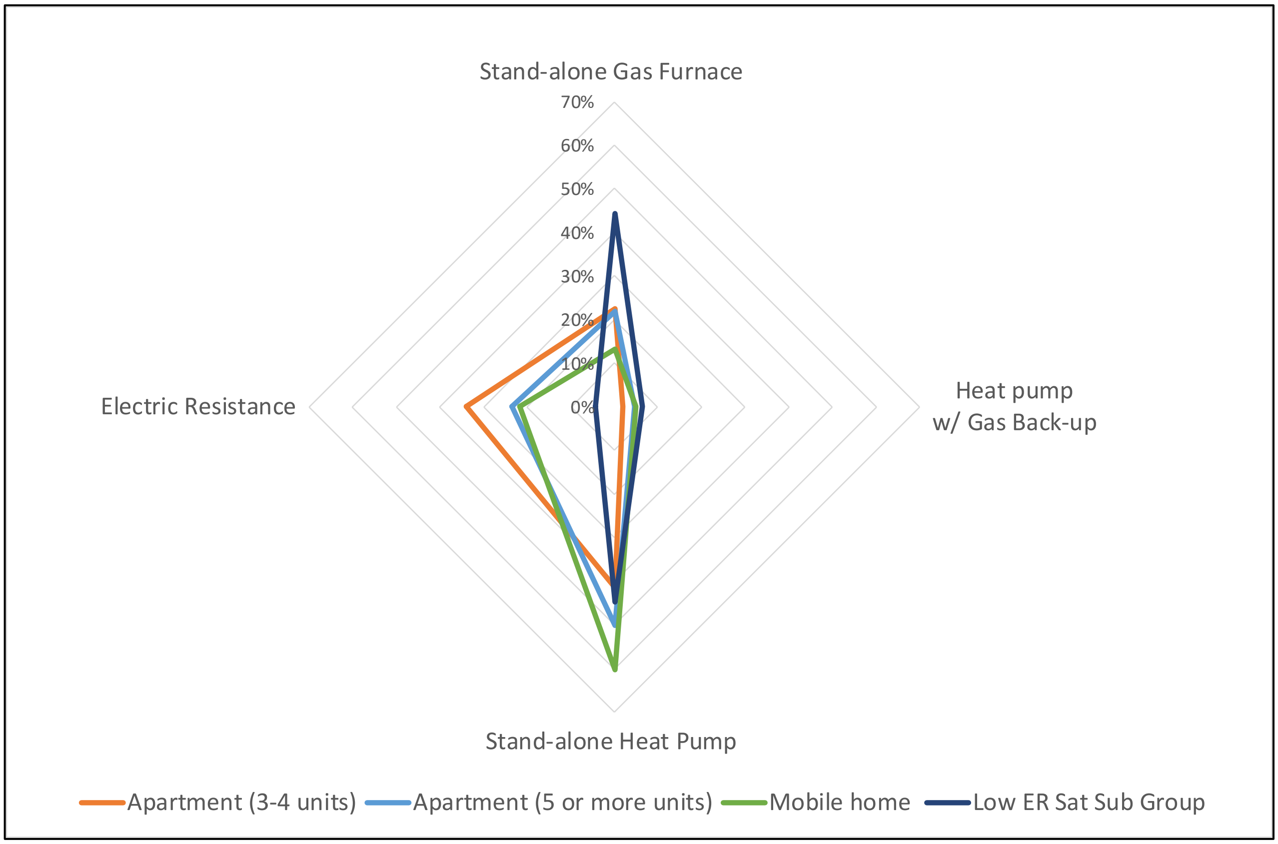
Resident Type	Stand-alone Gas Furnace	Heat Pump with Gas Back-up	Stand-alone Heat Pump	Electric Resistance	% Total Systems
Owner	79%	76%	74%	38%	73%
Renter	21%	24%	26%	62%	27%
Total	100%	100%	100%	100%	100%

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

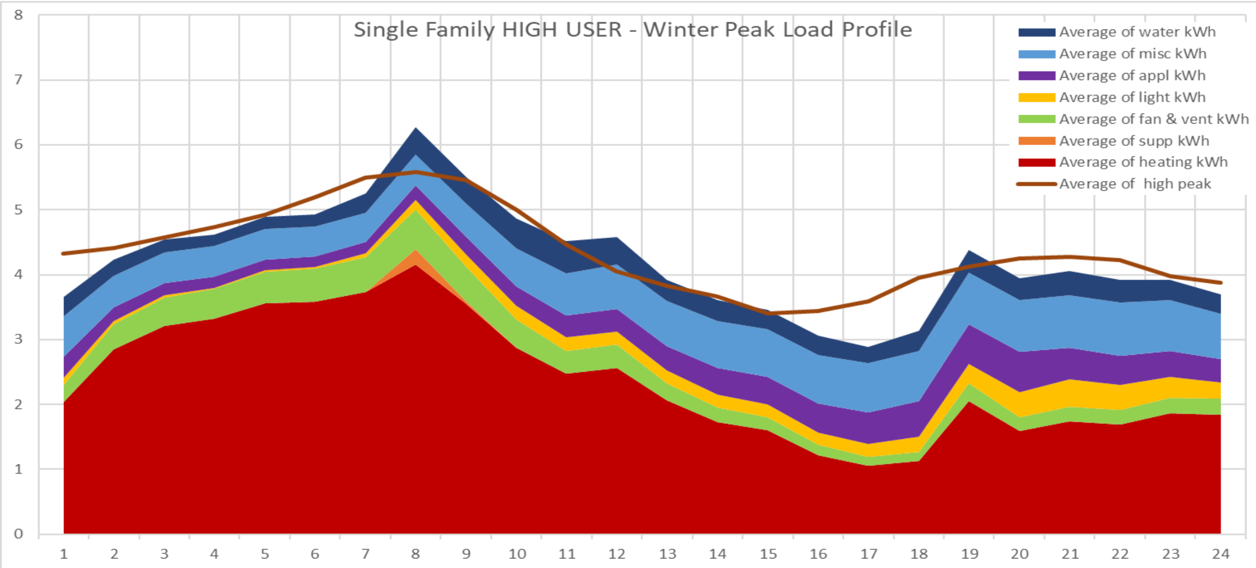


Figure 40. Single Family Peak Load Profile – Medium User

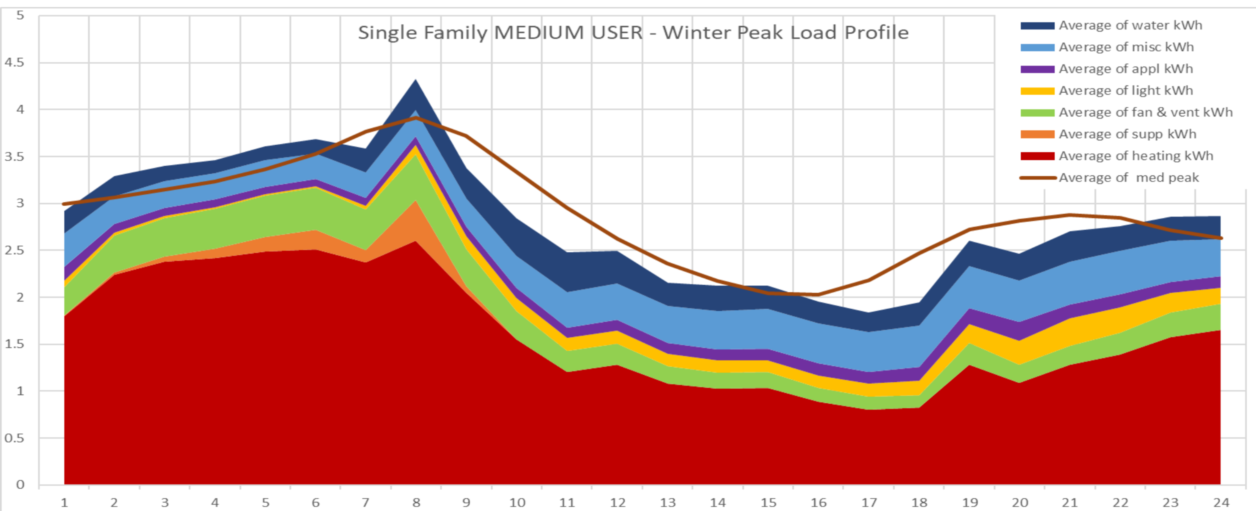
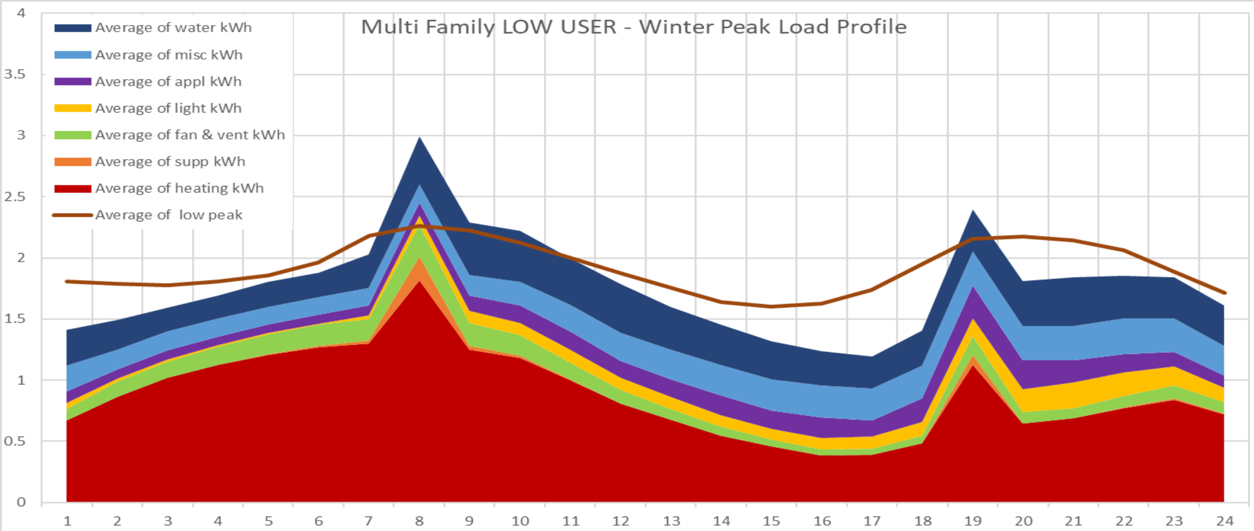
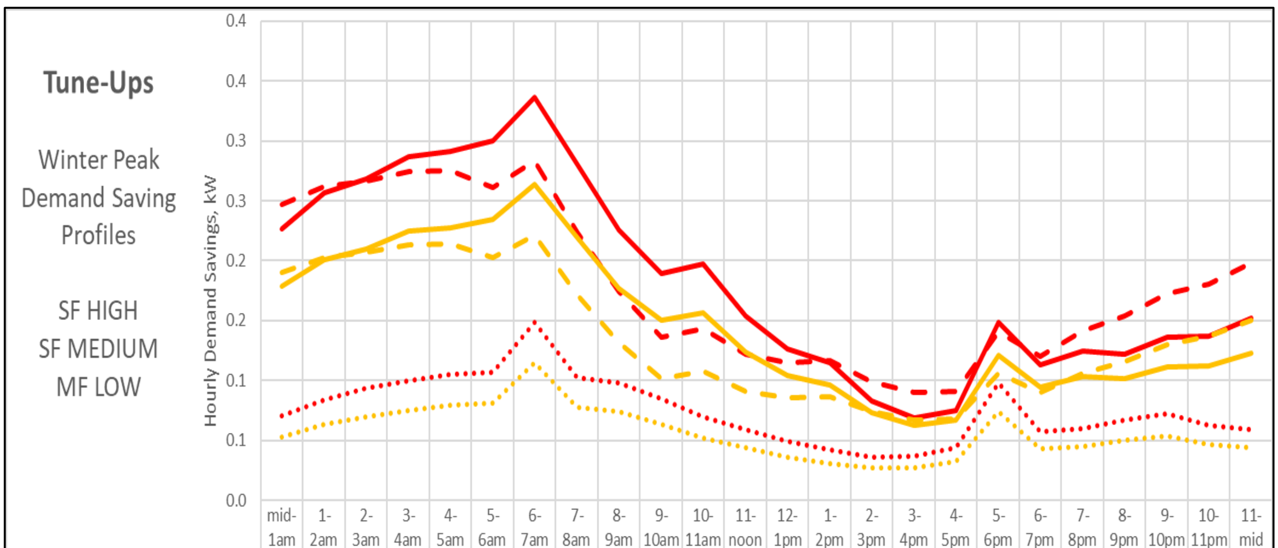


Figure 41. Multi-Family Peak Load Profile – Low User



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

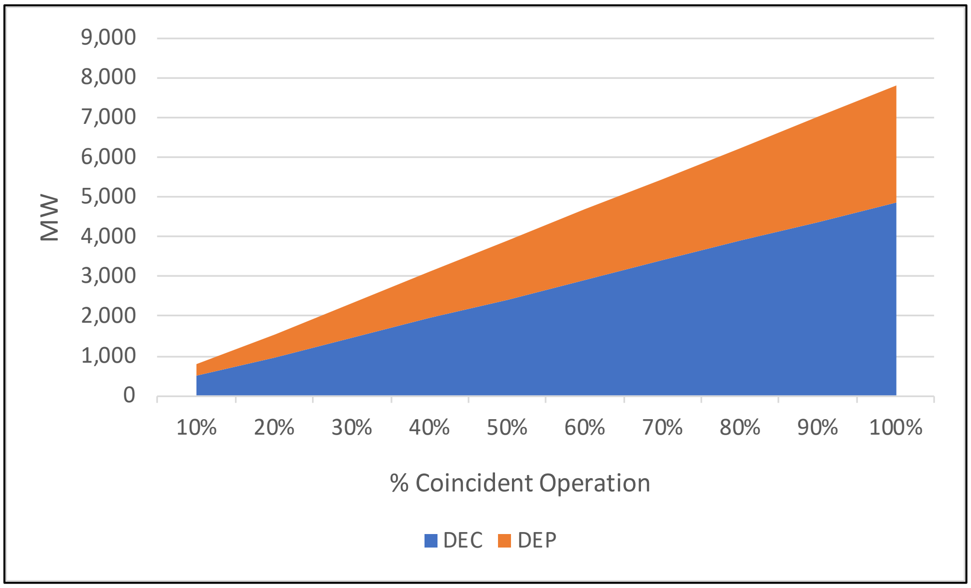
Table 25 shows technical demand from heat pump operation where technical demand is defined a worst-case scenario that assumes all system are operating simultaneously (i.e., 100% coincident operation). Reaching technical demand, is an unlikely event and Figure 40 shows the estimated heat pump loads at 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

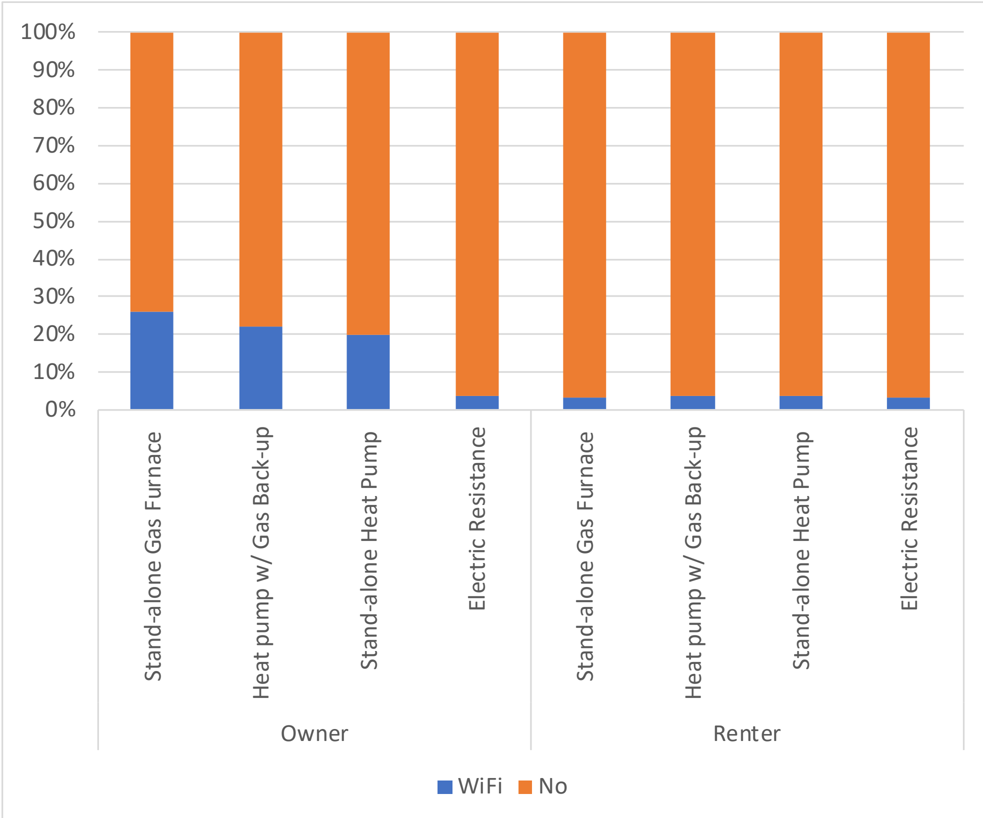
System Type	Wi-Fi
Stand-alone Gas Furnace	29%
Heat pump w/ Gas Back-up	26%
Stand-alone Heat Pump	24%
Electric Resistance	7%

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).

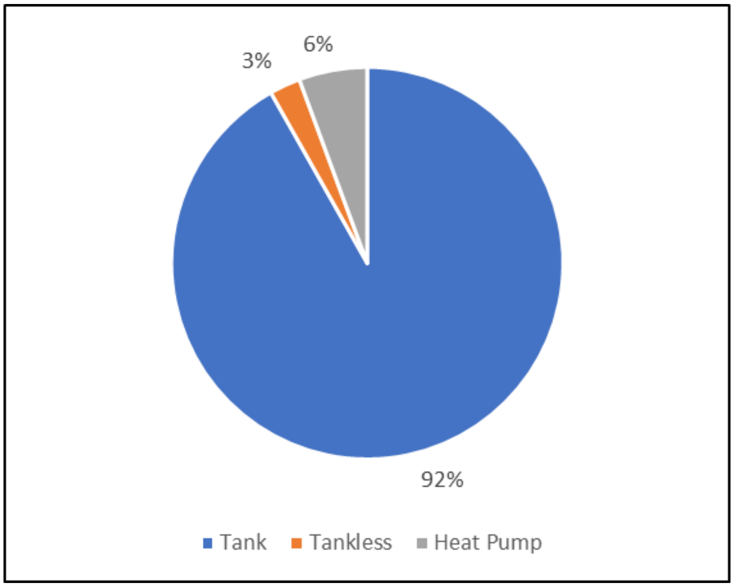
Table 28. Water Heat Fuel Type by Resident Type

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

Table 29. Water Heat Fuel by Dwelling Type

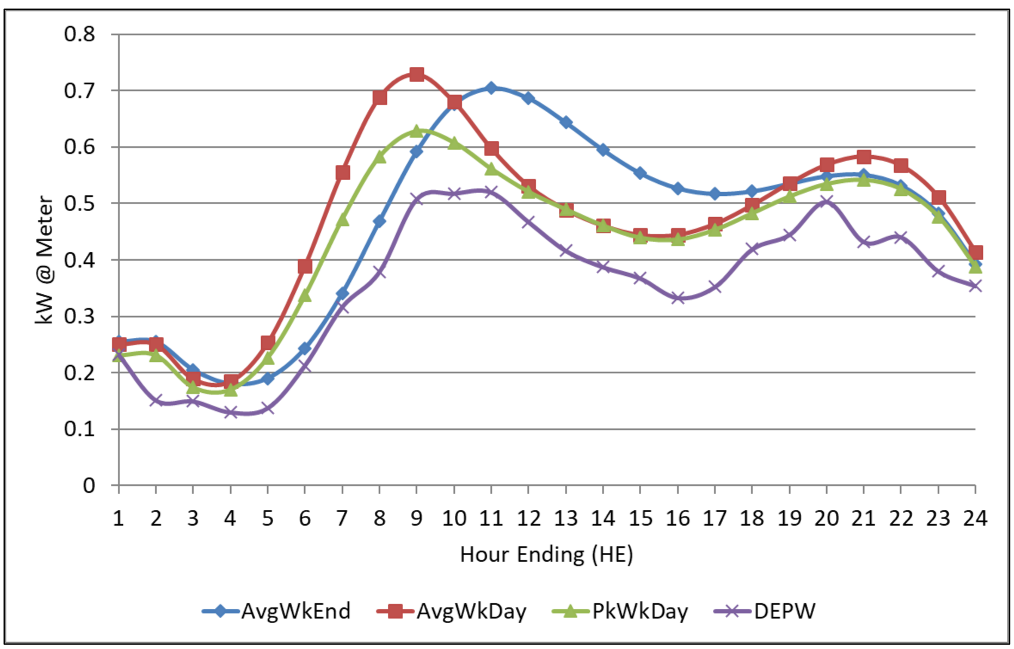
Resident Type	Fuel Type	Single-family detached	Single-family attached	Duplex	Condo	Apartment (3-4 units)	Apartment (5 or more units)	Mobile home
Owner	Electric	64%	50%	60%	76%			100%
	Natural Gas	36%	50%	40%	24%			0%
Renter	Electric	76%	82%	81%	84%	89%	91%	100%
	Natural Gas	24%	22%	19%	16%	11%	9%	0%

Figure 45. Water Heater Design Types



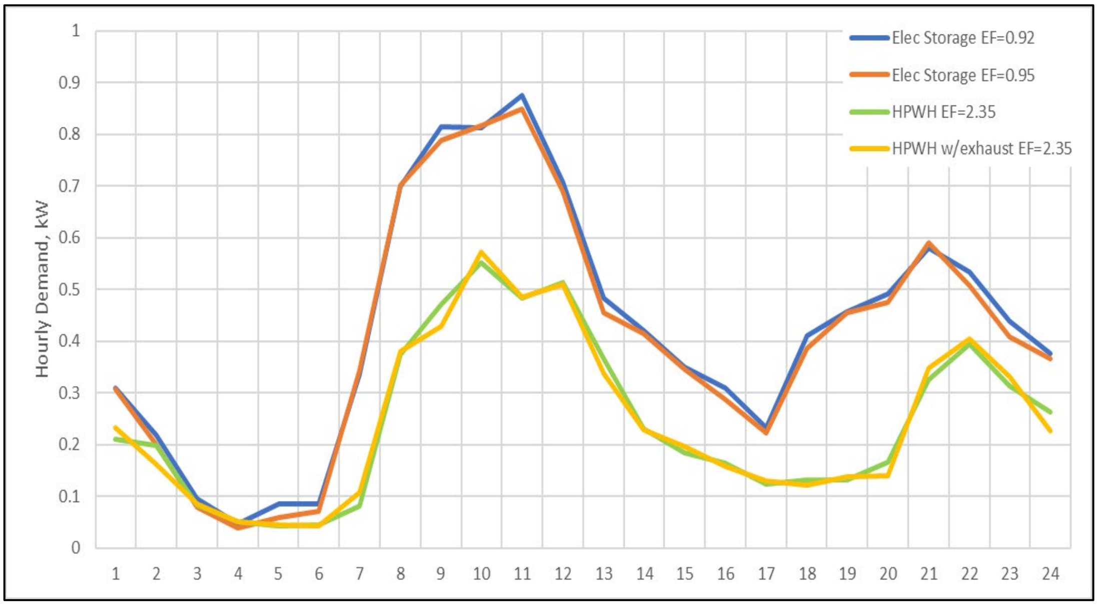
We reviewed various studies defining load shapes for electric water heaters, and these show load profiles similar to an EPRI study completed for the ECAR Region and DEP West, shown in Figure 43,[36] that feature a morning and evening peak. In general, these studies indicate weekday peak loads between 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:

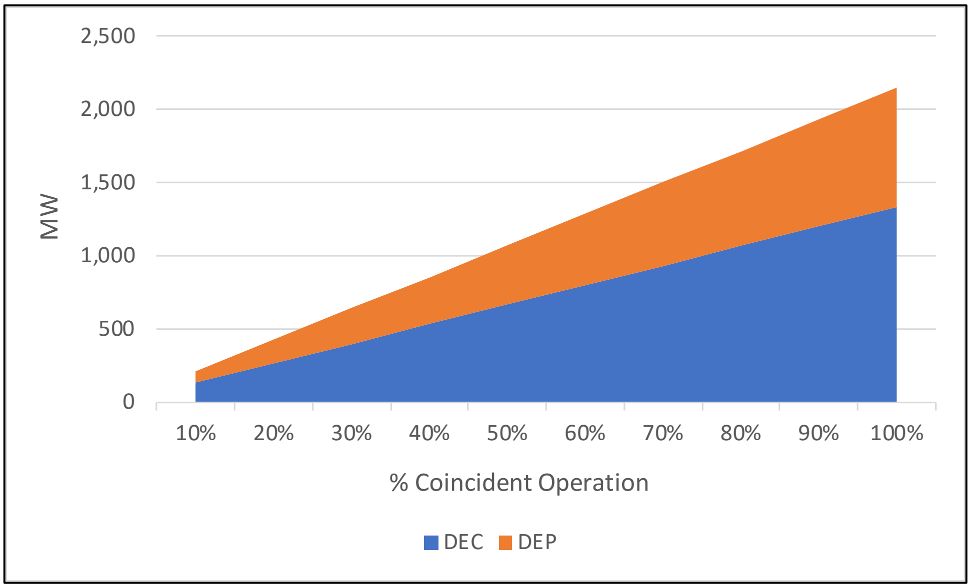
- As presented in 2019 RASS, 71% of all hot water heating systems are electric.
- Hot water heating represents about 10% of electric home demand during peak load periods where appliances and heat pumps are also operating coincident with the water heater.

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

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

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

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

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

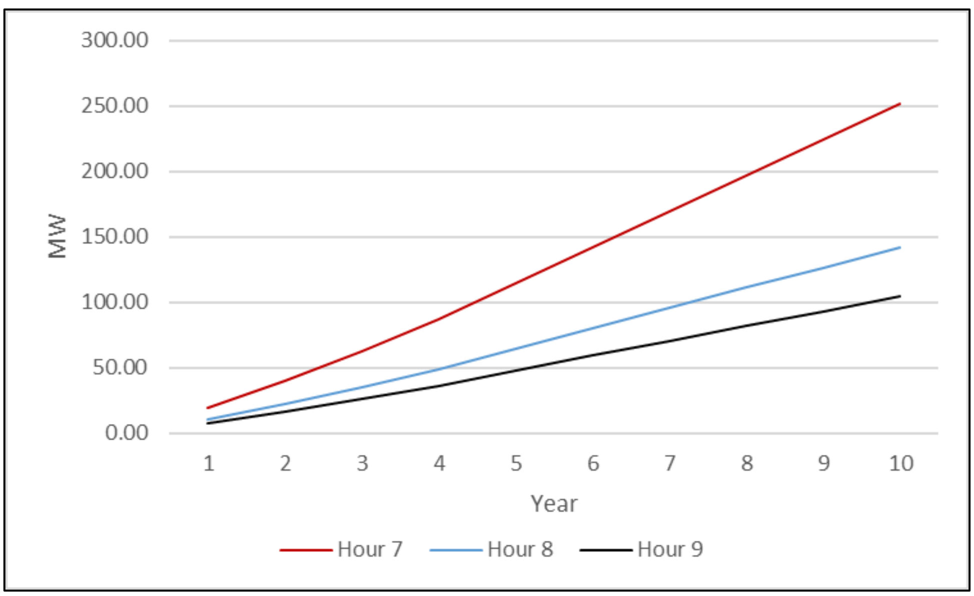
Hour Ending	5	6	7	8	9	10
SF	-1.38	-0.84	1.70	0.96	0.71	-1.04
MF	-0.60	-0.35	0.95	0.53	0.42	-0.45

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

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

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

Figure 49. 10-Year BYOT Savings Forecast by Hour



Rate Enabled Thermostats (RET)

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

Table 33. Hourly RET kW Impacts by Dwelling Type

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

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

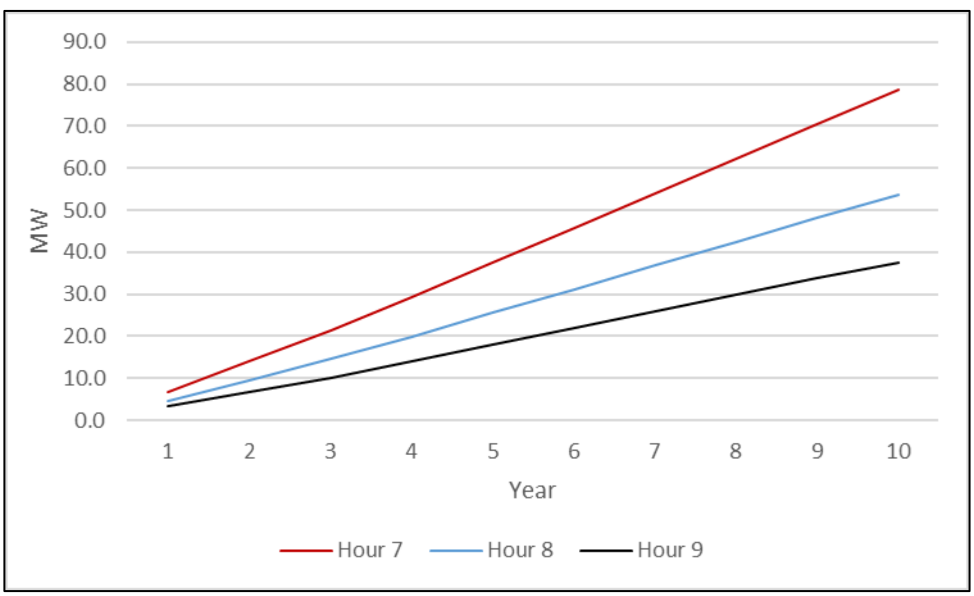
Hour Ending	5	6	7	8	9	10
SF	-2.23	-1.29	2.03	1.41	0.98	-1.67
MF	-1.02	-0.59	1.25	0.75	0.59	-0.76

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

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

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

Figure 50. 10-Year RET Savings Forecast by Hour



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

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

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

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

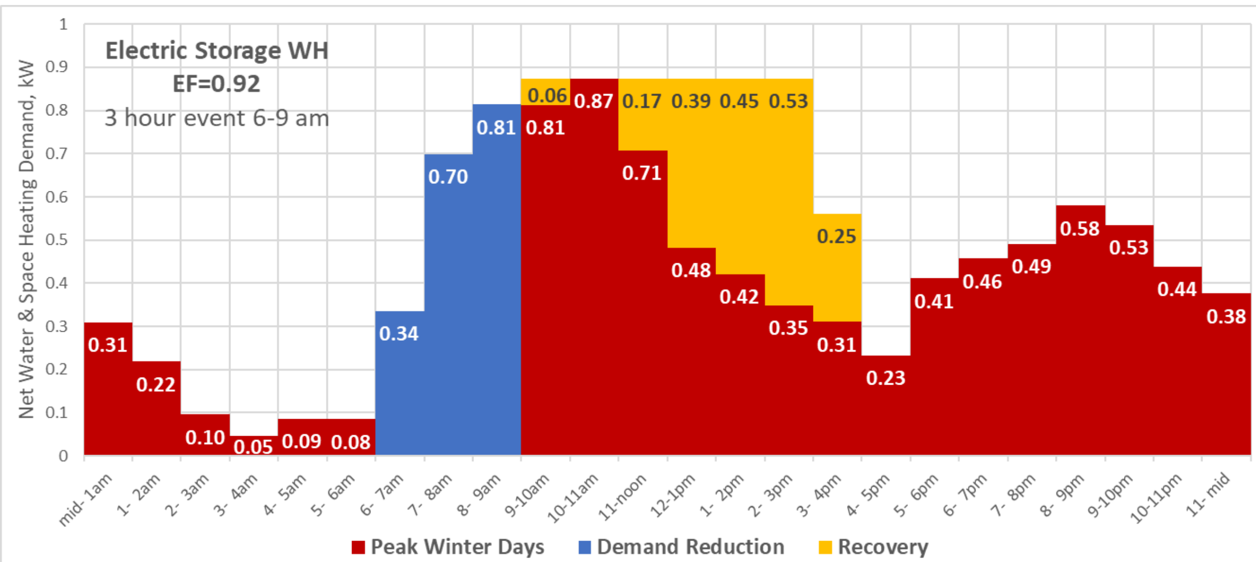
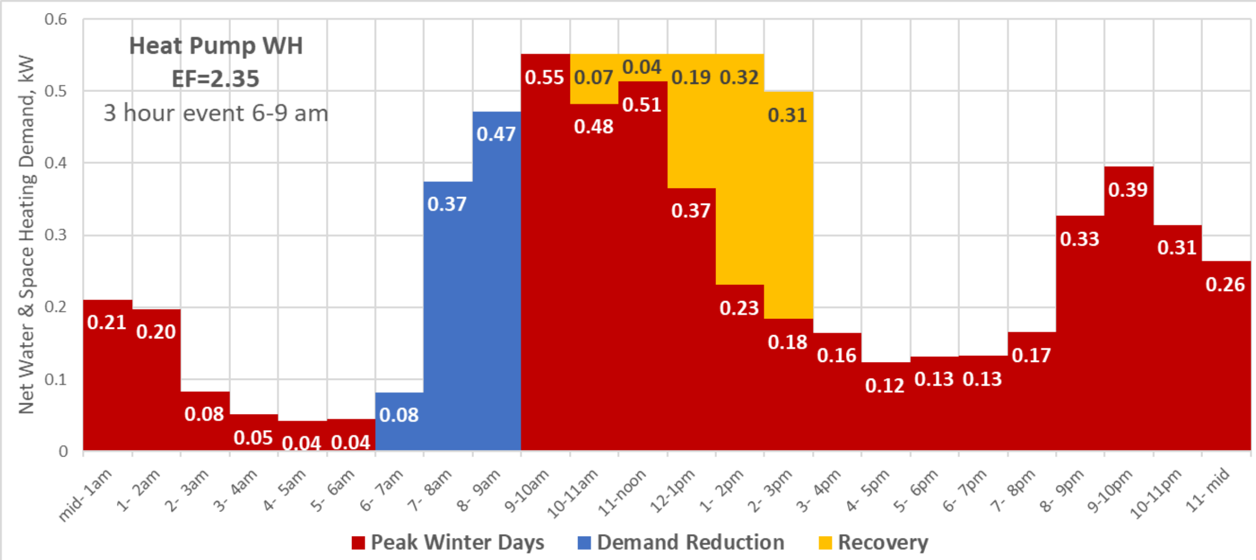


Figure 52. Modelled Heat Pump Water Heater Peak Load Shed Profile



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

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

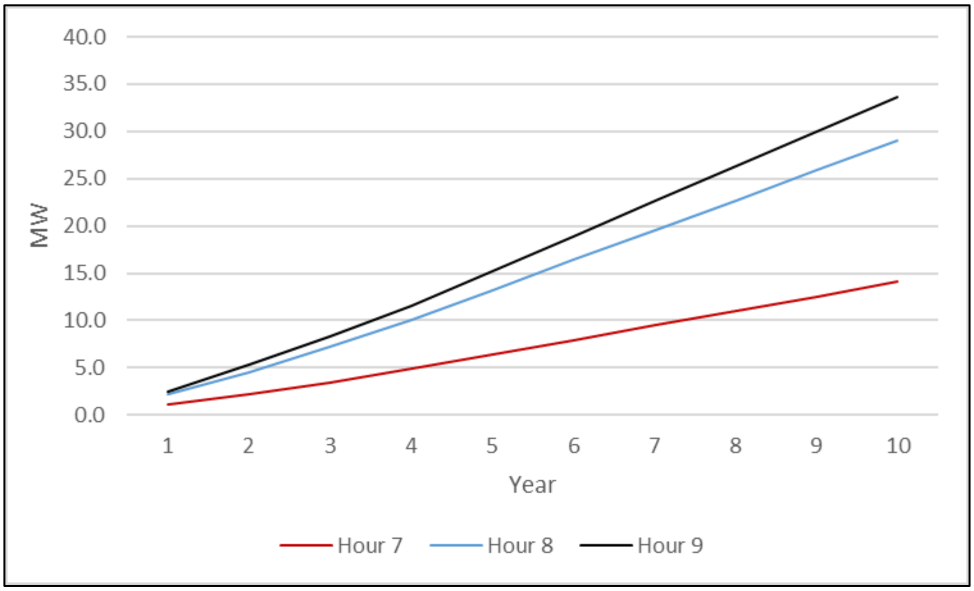
Hours Ending	5	6	7	8	9	10	11	12	13	14	15	16
SF	0.00	0.00	0.34	0.70	0.81	-0.06	0.00	-0.17	-0.39	-0.45	-0.53	-0.25
MF	0.00	0.00	0.26	0.53	0.61	-0.05	0.00	-0.13	-0.29	-0.34	-0.40	-0.19

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

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

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

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



5. Small and Medium C&I Market and Solutions

Rate Definitions

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

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

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

Table 36. Small and Medium C&I Rates Summary

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

Peak Load Profile

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

DEC

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

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

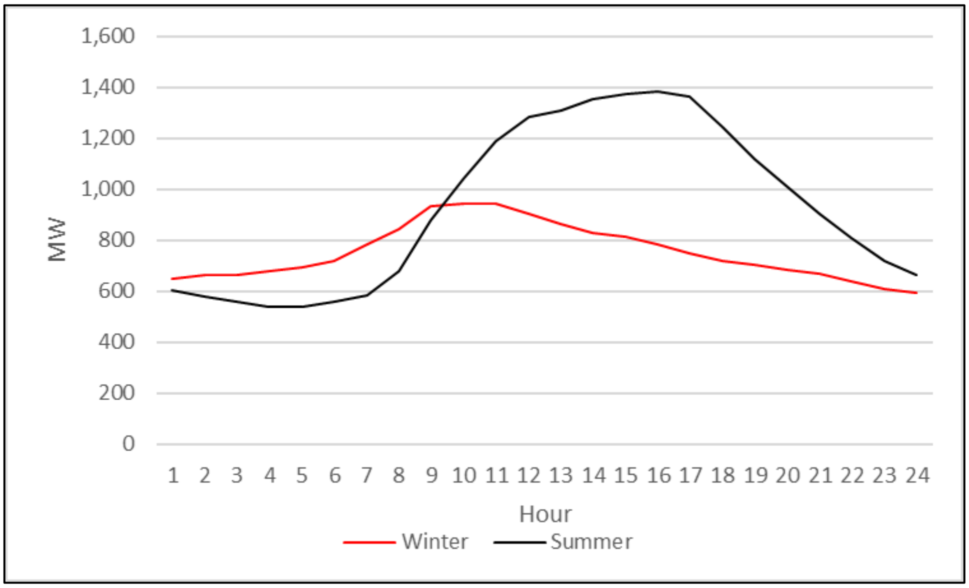
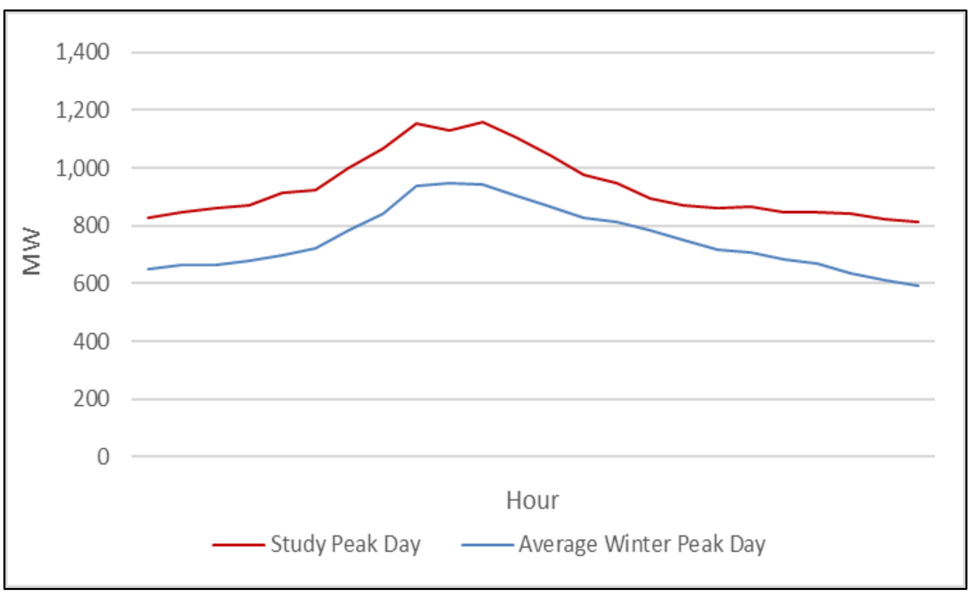


Figure 55. DEC 2018 SGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



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

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

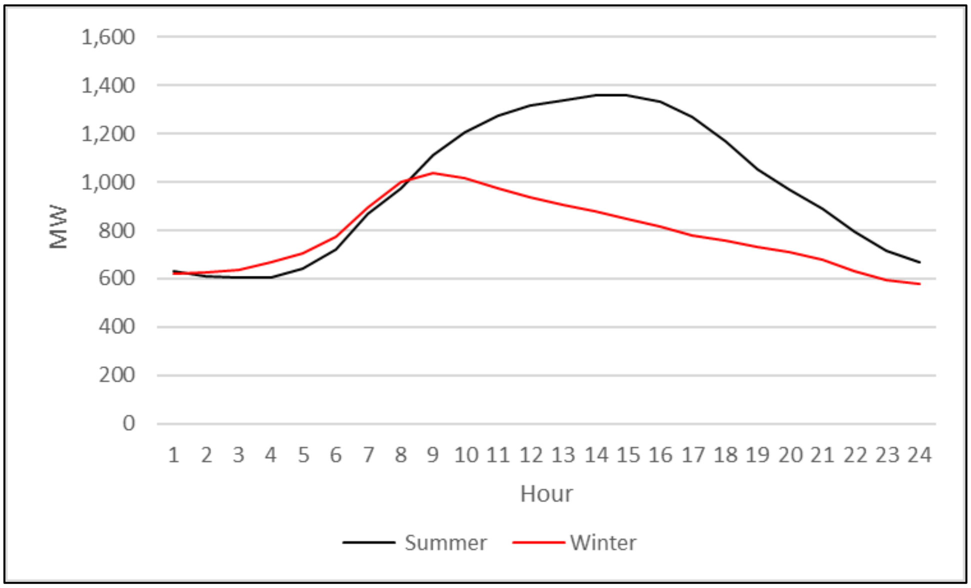


Figure 57. DEC 2018 LGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day

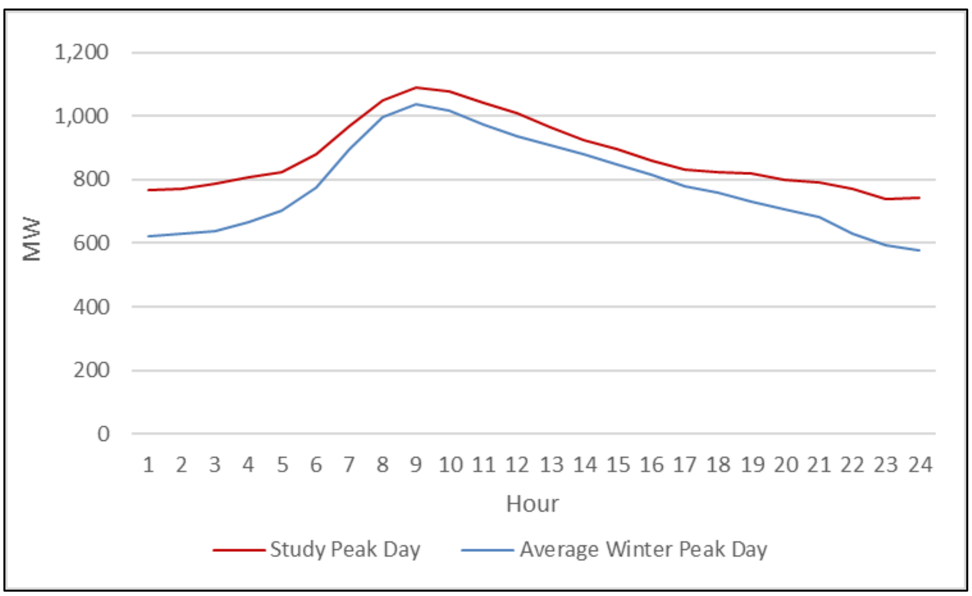


Figure 55 and Figure 56 show a similar review of the DEC Ind rate, indicating that these customers are a blend of industrial and commercial operations though no segment data was provided. These load shapes are virtually identical, and while there is some demand associated with electric heating, most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

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

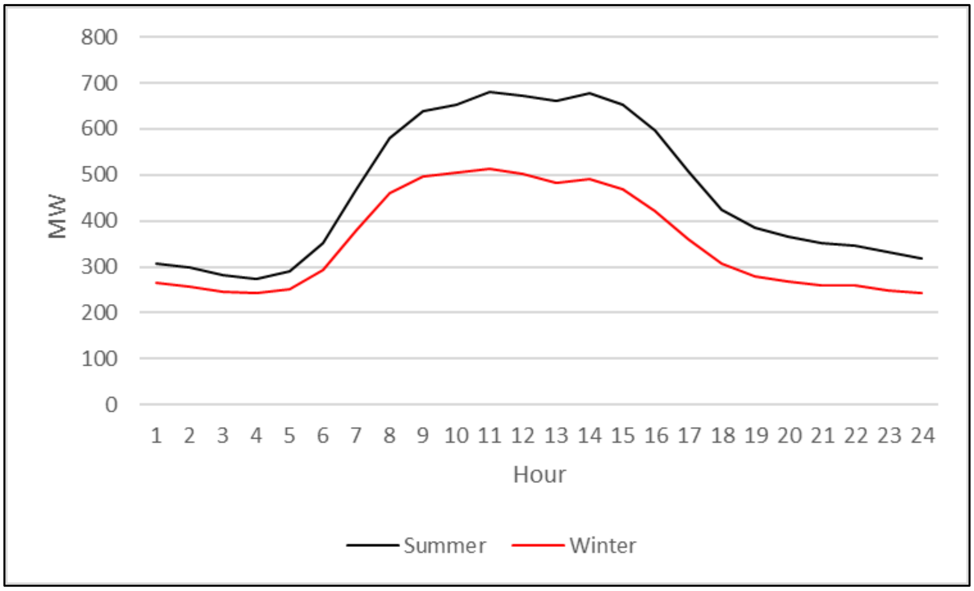
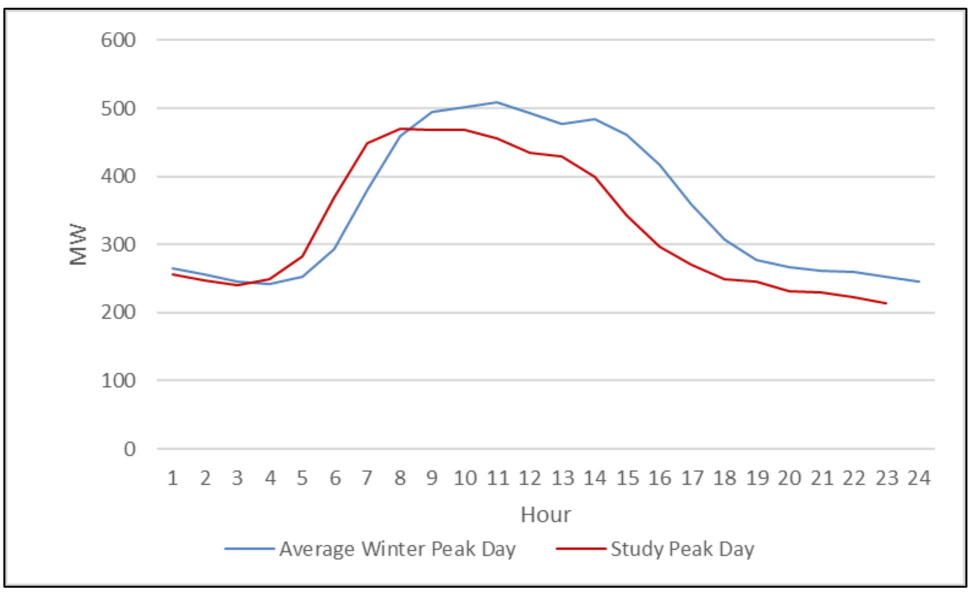


Figure 59. DEC 2018 Ind Demand Profile – Study Peak Day Vs. Average Winter Peak Day



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

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

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

DEP

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

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

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

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

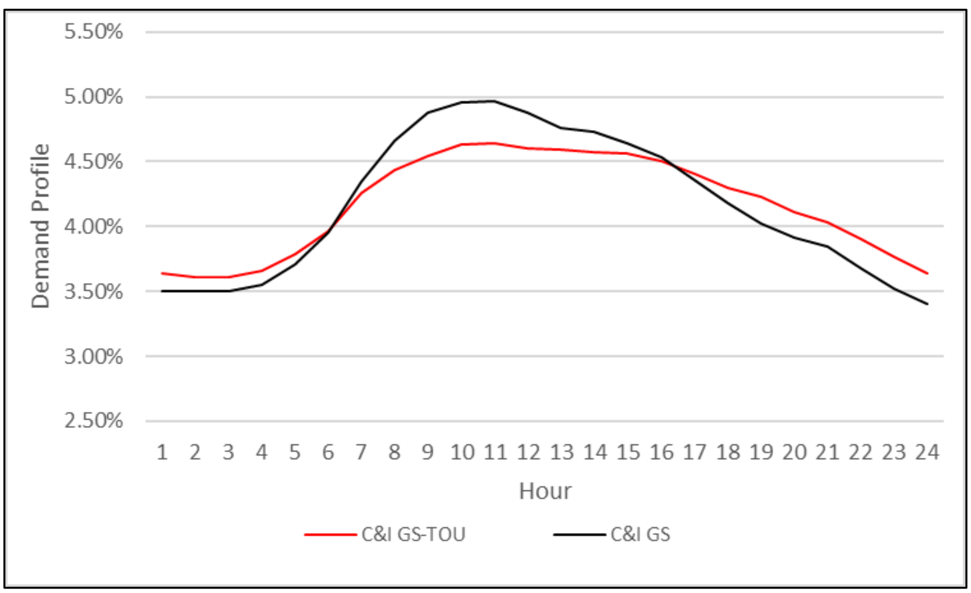
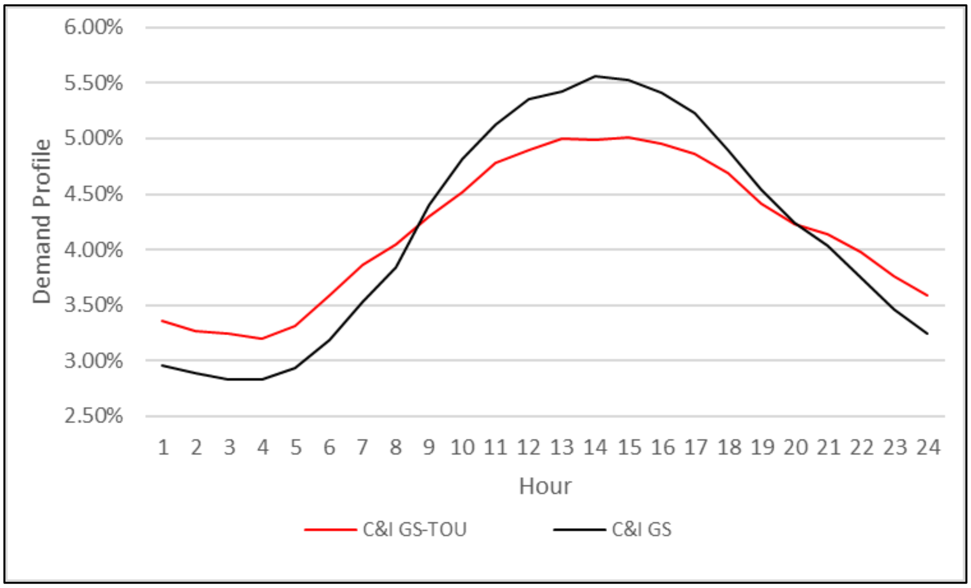


Figure 61. DEP Small-Medium C&I Aggregate Rate Demand Profile - Average Summer Peak Day



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

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

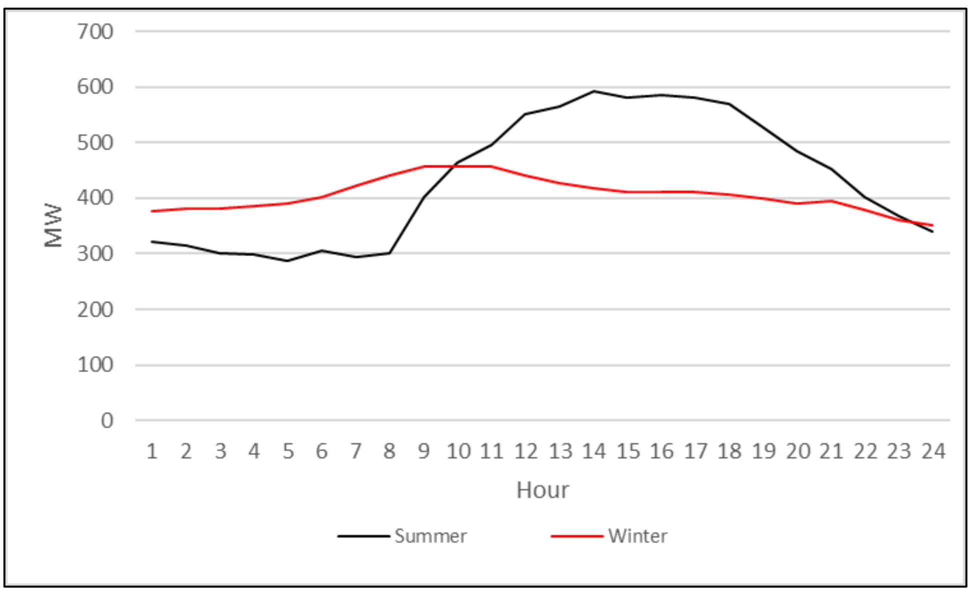
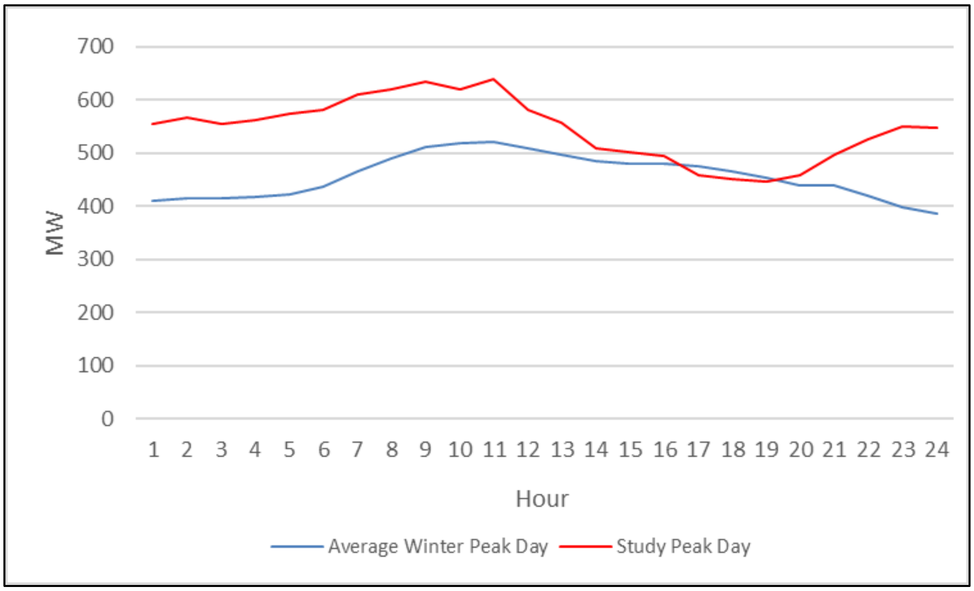


Figure 63. DEP 2018 SGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



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

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

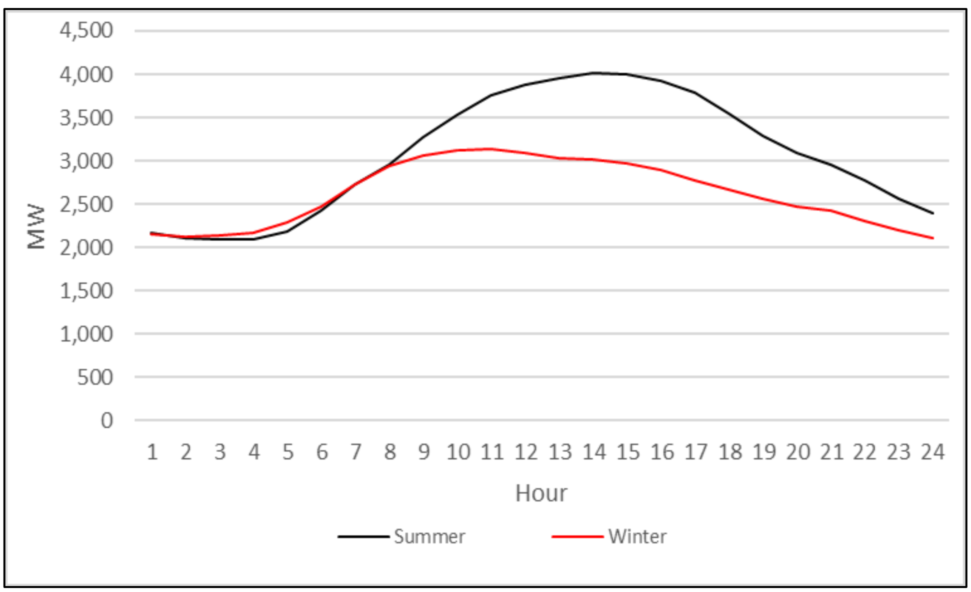


Figure 65. DEP 2018 MGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day

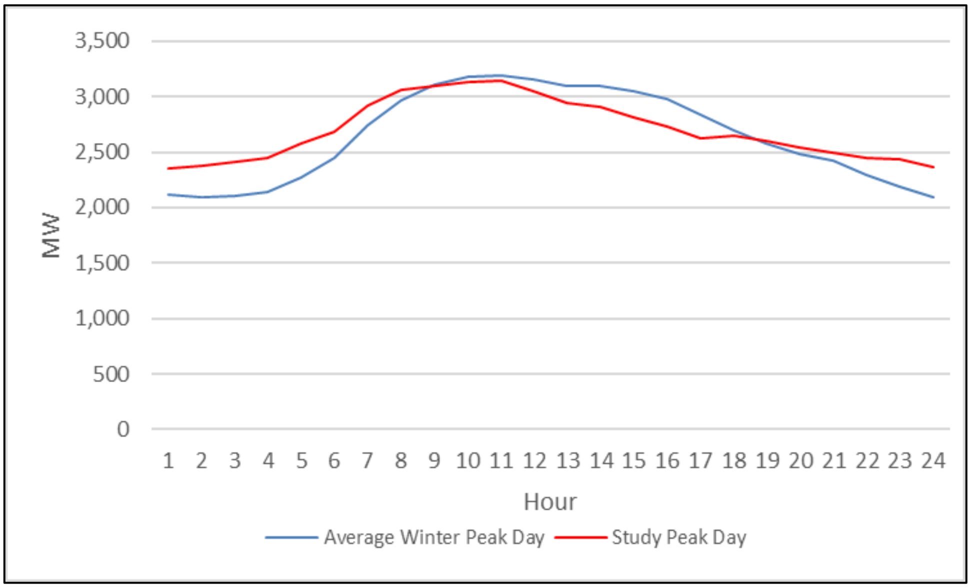


Figure 63 shows average summer and winter peak day for the LGS rate, indicating a higher demand during summer, similar to the SGS rate. Figure 64 compares demand between the study peak day and the average winter peak days, showing a difference of -8 MW, indicating that this rate class is not sensitive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

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

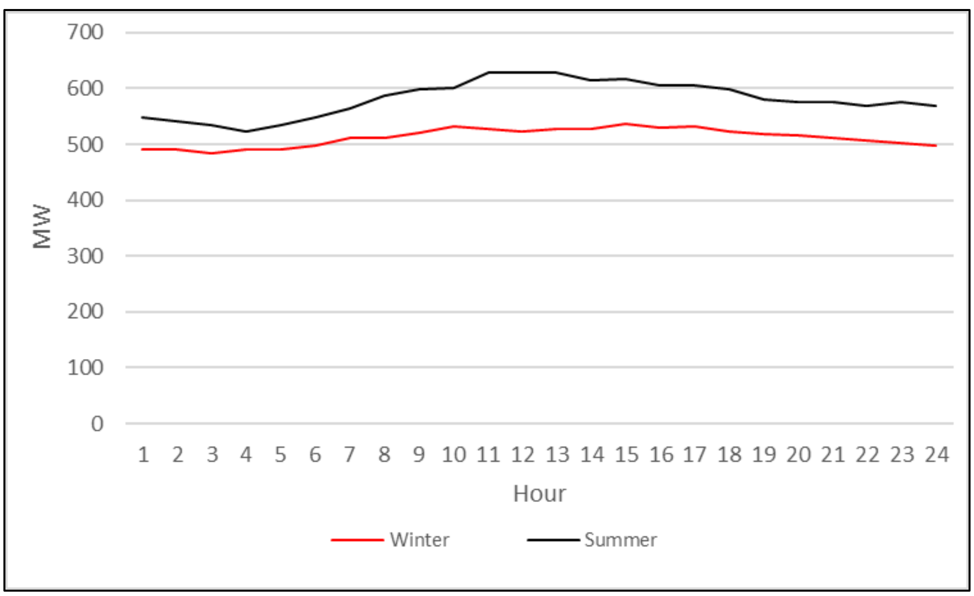
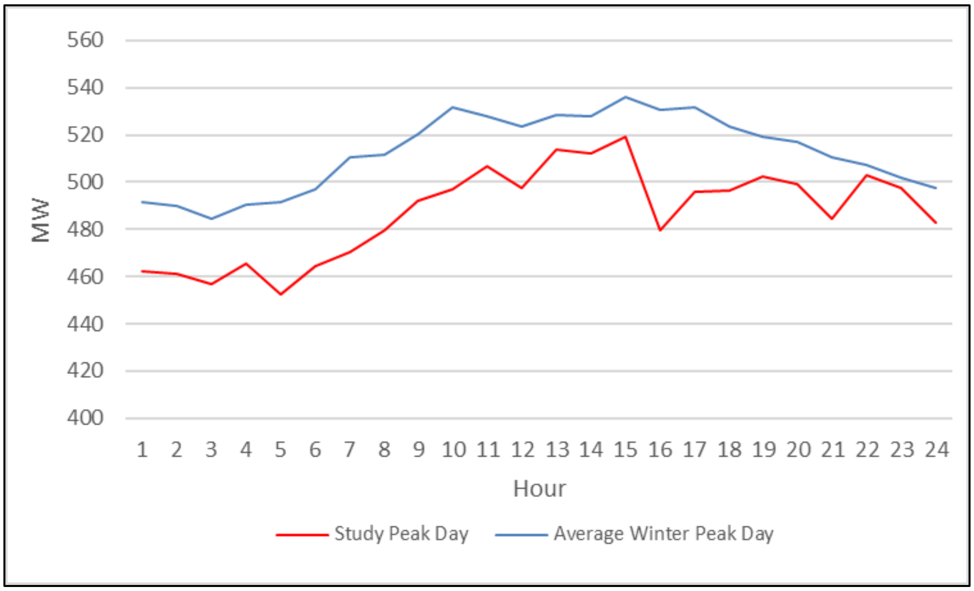


Figure 67. DEP 2018 LGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



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

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

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

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

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

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

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

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

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

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

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

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

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

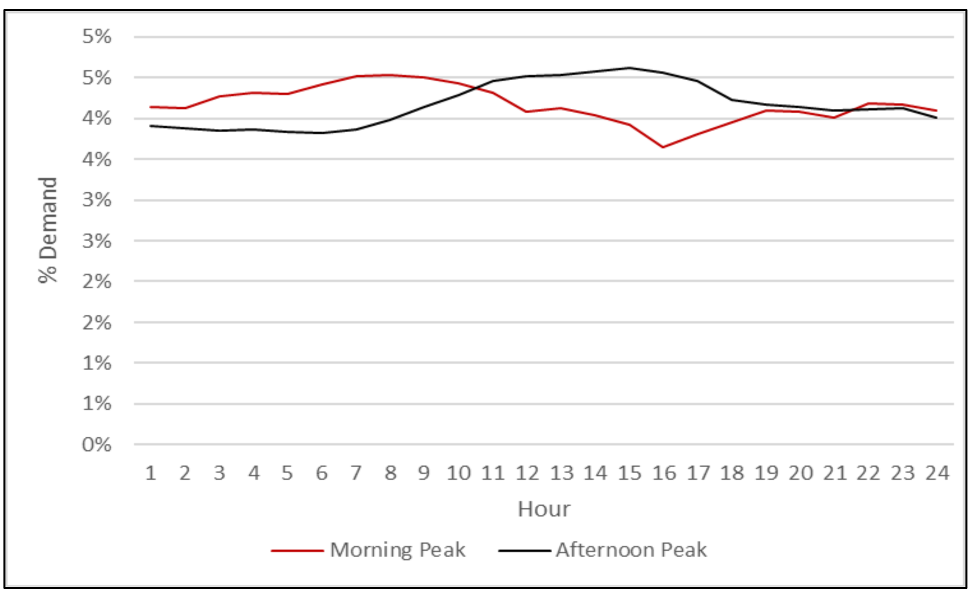


Figure 69. DEP Large C&I Morning Peak Exceeds Afternoon Peak by 10% – Average Season Peak Day

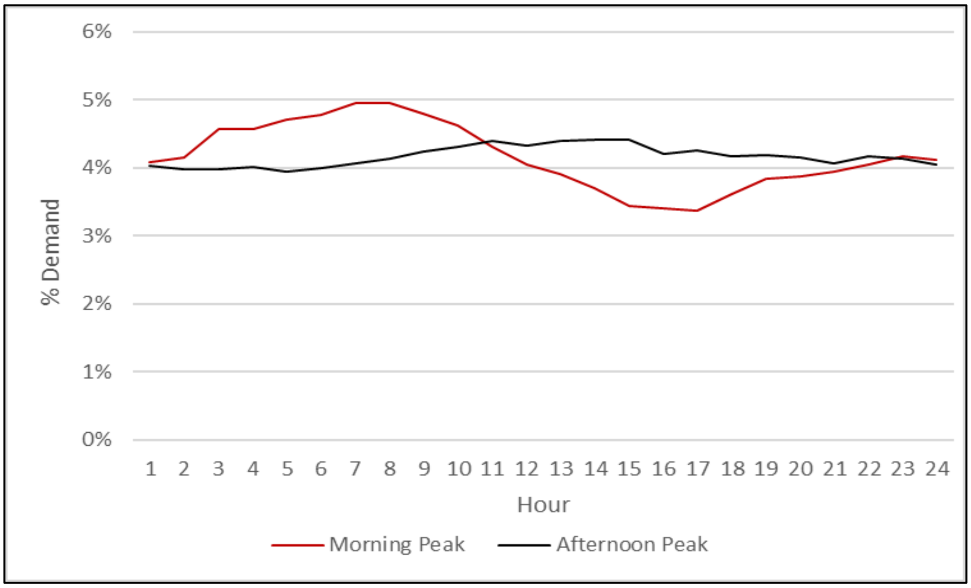
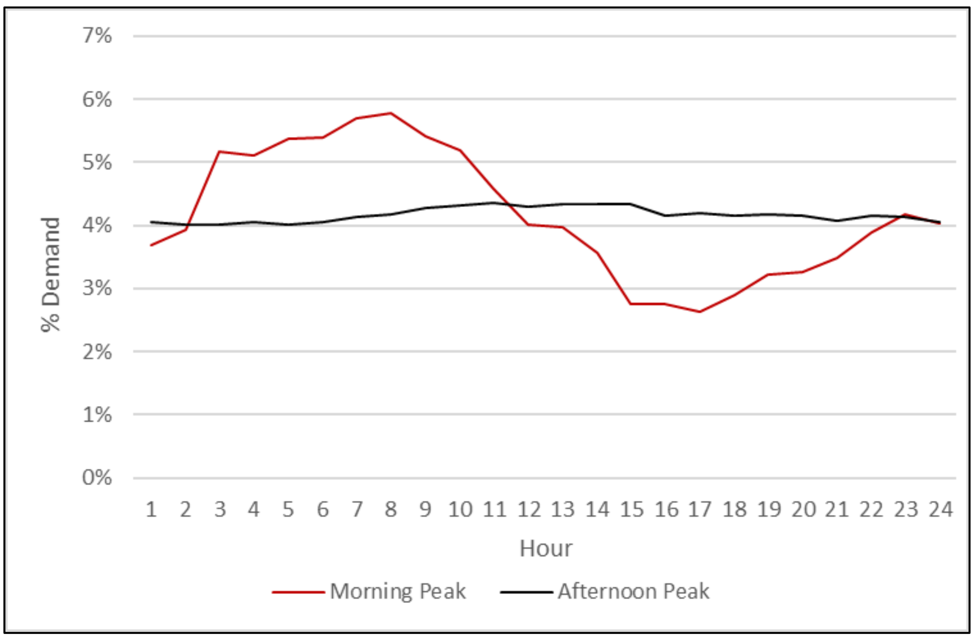


Figure 70. DEP Large C&I Morning Peak Exceeds Afternoon Peak by 20% – Average Season Peak Day



Market Characteristics

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

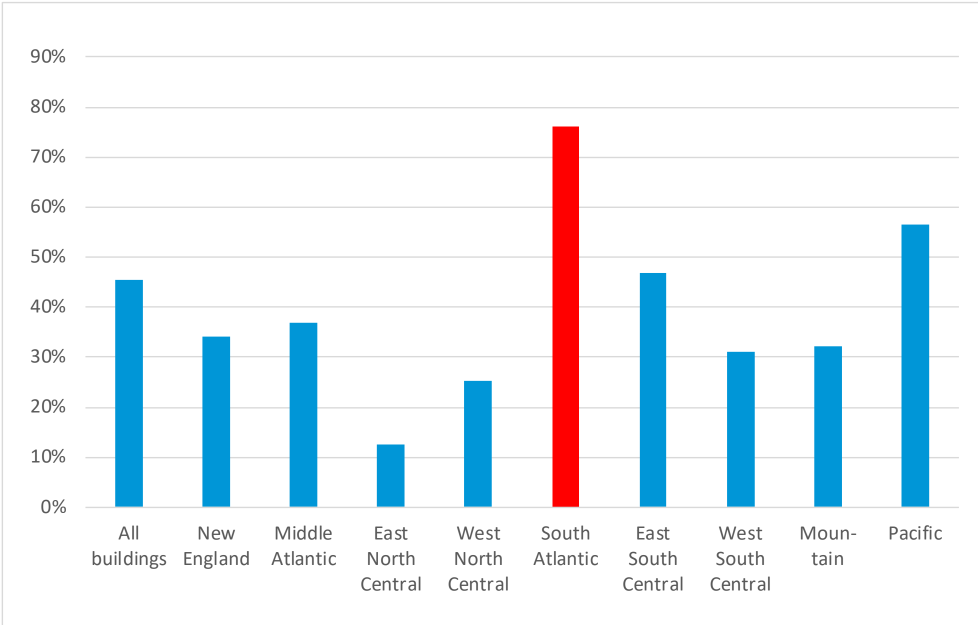
Space Heating

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

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

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

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



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

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

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

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

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

[39] This is saturation of building count, not saturation of square footage
[40] Defined as total demand if all systems are operating at the same time

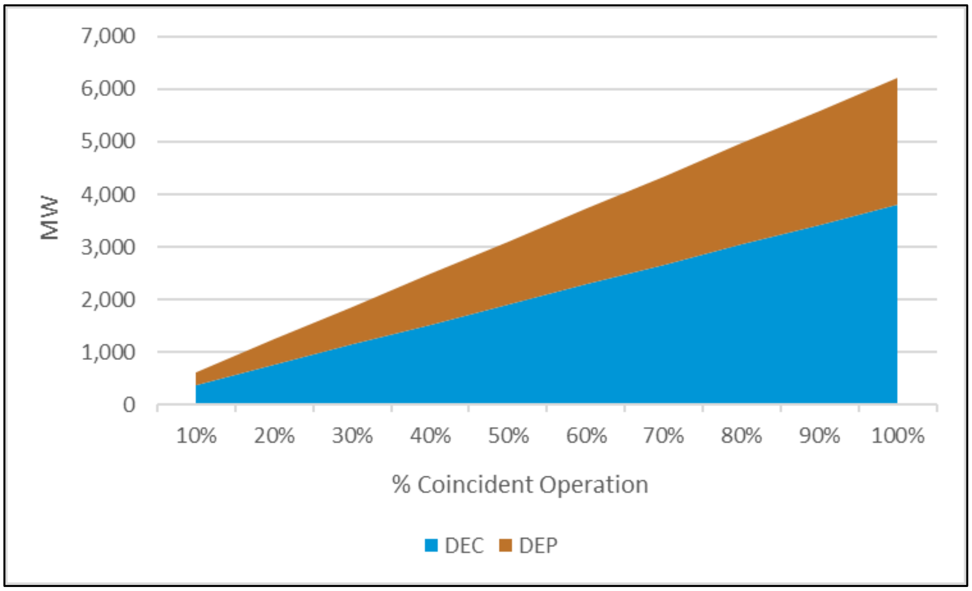
- 3.5 kW/ton
- 630 sq. ft./ton for all building type except for warehouse and storage, where we estimate 3,000 sq. ft. / ton

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

Table 42. Estimated Heat Pump Heating Technical Demand

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

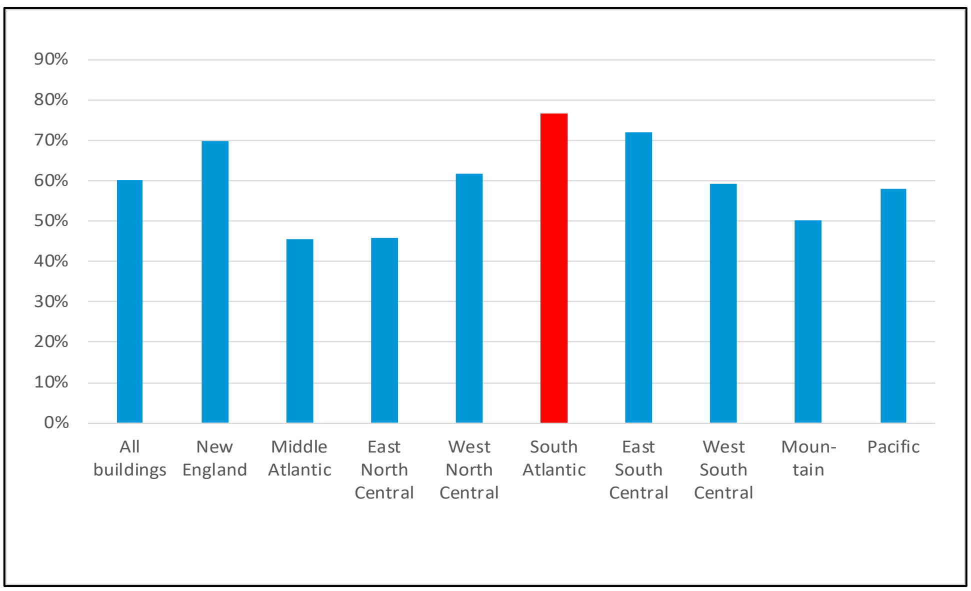
Figure 72. Commercial Heat Pump Operating Coincidence Demand



Hot Water Heating

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

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



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

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

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

Figure 74. Commercial Electric Hot Water Heater Shipment Trends

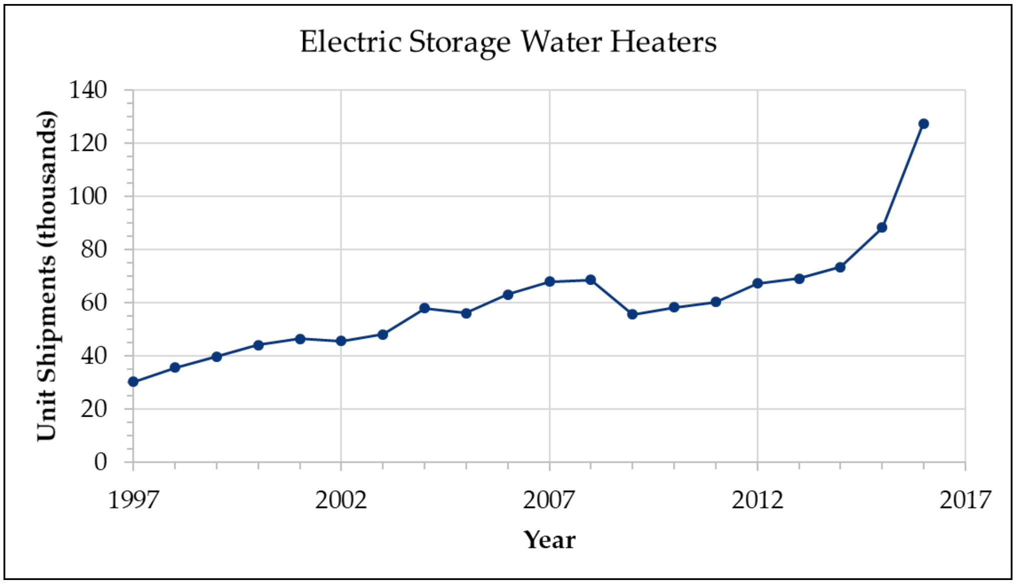
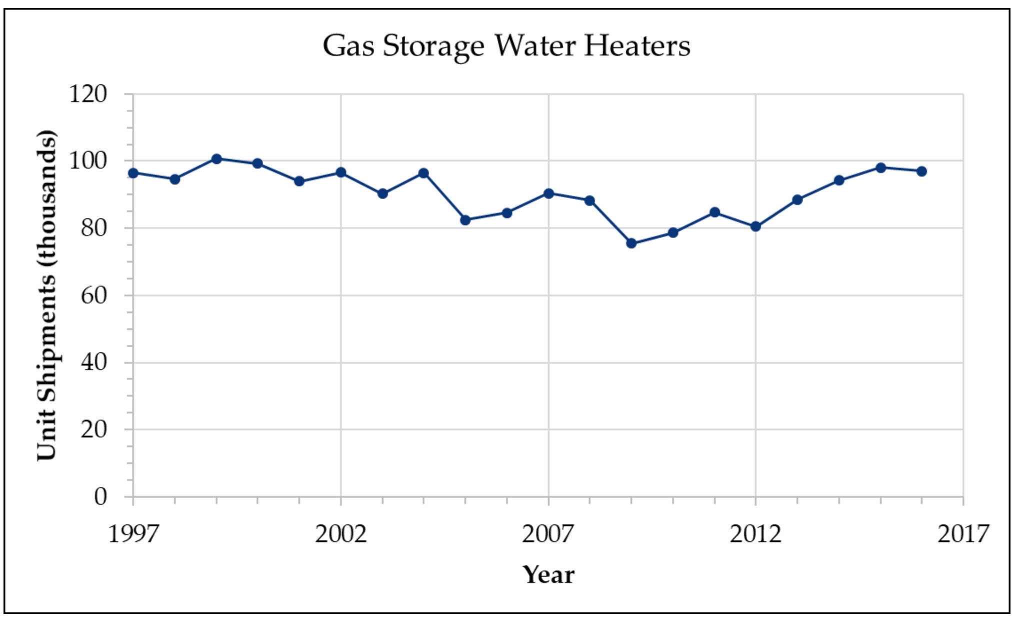


Figure 75. Commercial Natural Gas Hot Water Heater Shipment Trends



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

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

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

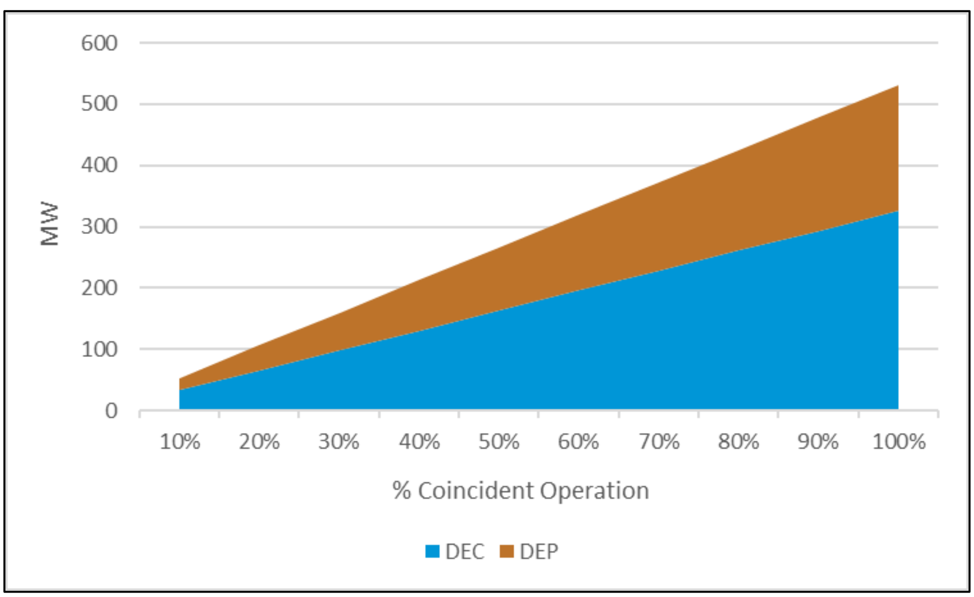
- Ratio of commercial CHWH heater size to average residential CHWH size = 2.38
- Average kW demand during winter morning peak period = 1.93 kW

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

Table 43. Estimated Electric HWH Technical Demand

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

Figure 76. Commercial Electric HWH Operating Coincidence Demand



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

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

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

Solution Set Recommendations

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

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

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

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

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

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

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

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

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

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

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

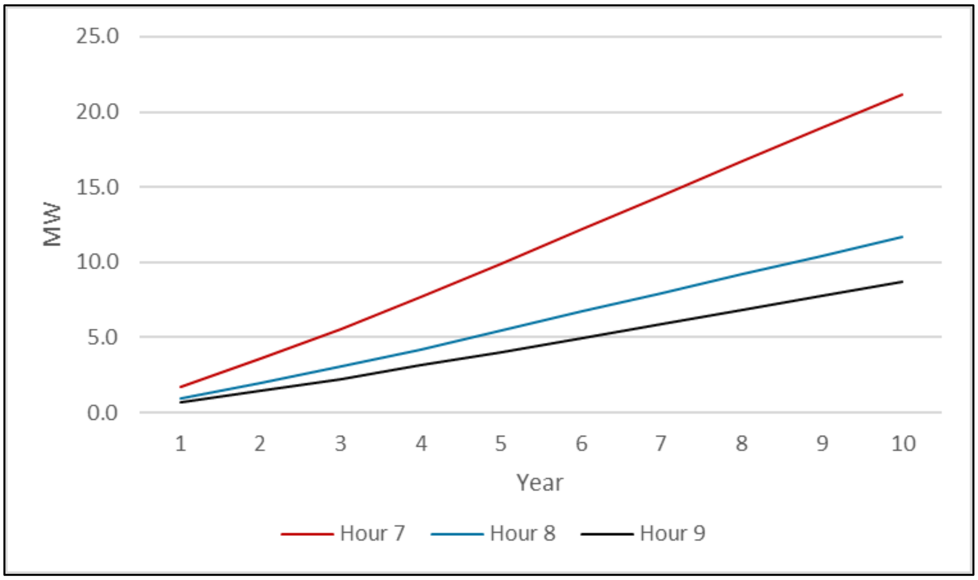
Figure 72 shows the forecast by hour over a 10-year horizon based on the following assumptions for the combined C&I BYOT and RET offering:

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

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

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

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



Automated Demand Response

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

Solution Set Measures Considered but Not Forecast

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

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

6. Large C&I Market and Solutions

Rate Definitions

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

Table 45. Large C&I Rates Summary

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

Peak Load Profile

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

DEC

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

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

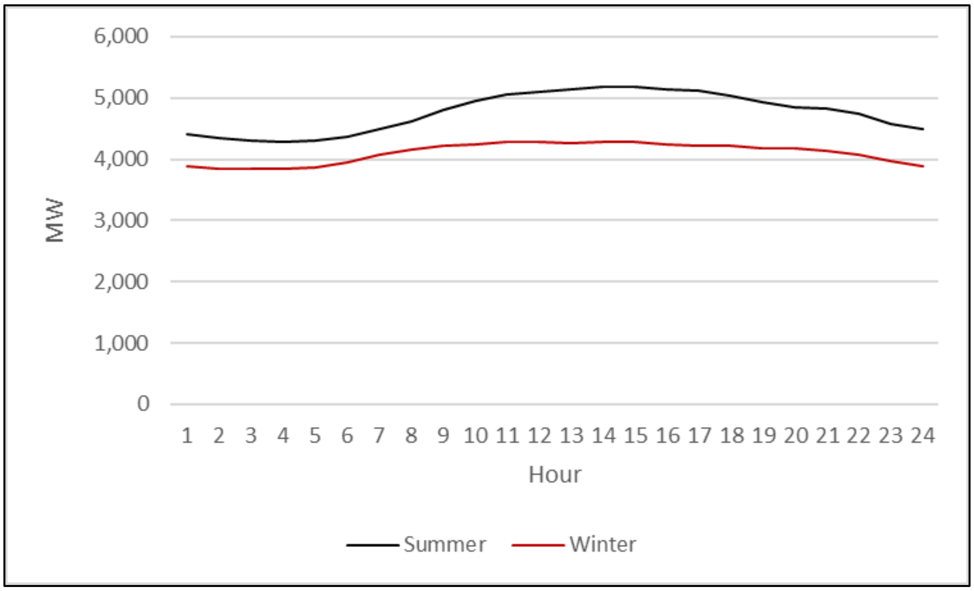


Figure 79. DEC 2018 Large C&I - Study Peak Day

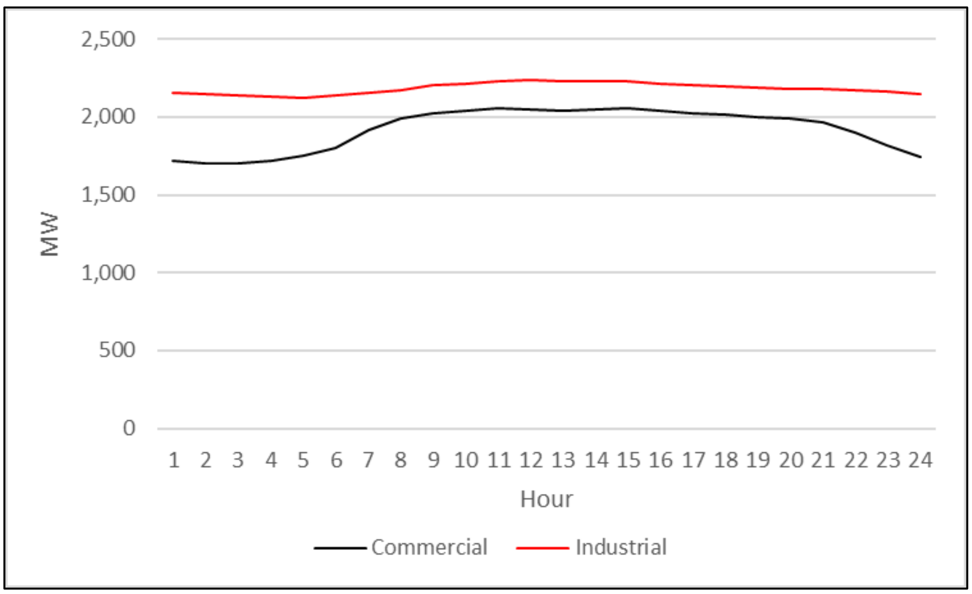


Figure 77 looks at the study peak day and adjusts the scale to emphasize the difference in load shapes between commercial and industrial TOU customers. We analyzed the underlying data and estimate that the heating load attributable to Opt-C customers is 155 MW by comparing average demand of 2,108 MW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

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

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

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

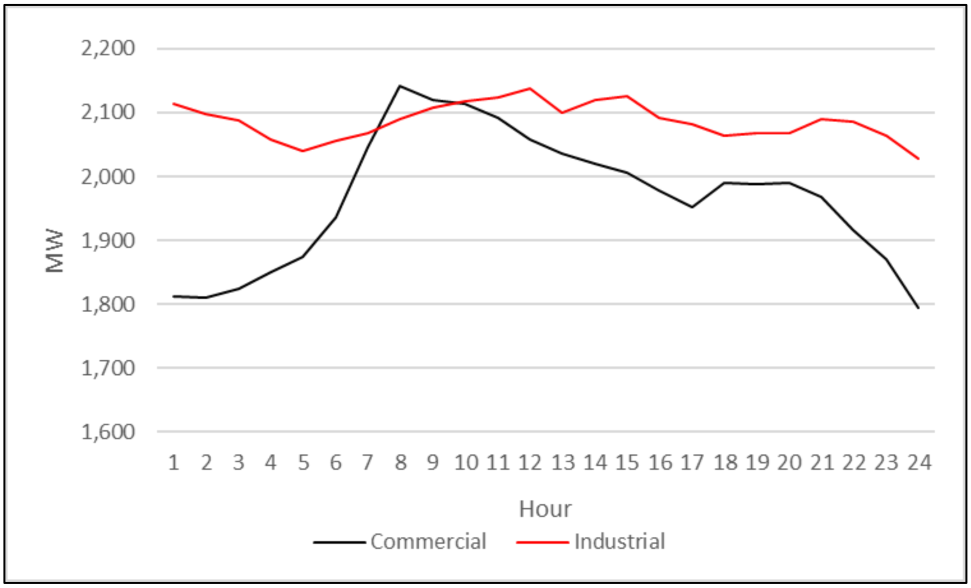


Figure 77 compares demand between the study peak day and the average winter peak days for Opt-C customers, showing a difference of about 130 MW between hours 7:00 and 8:00, indicating that these customers have demand associated with heating that is moderately sensitive to weather events.

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

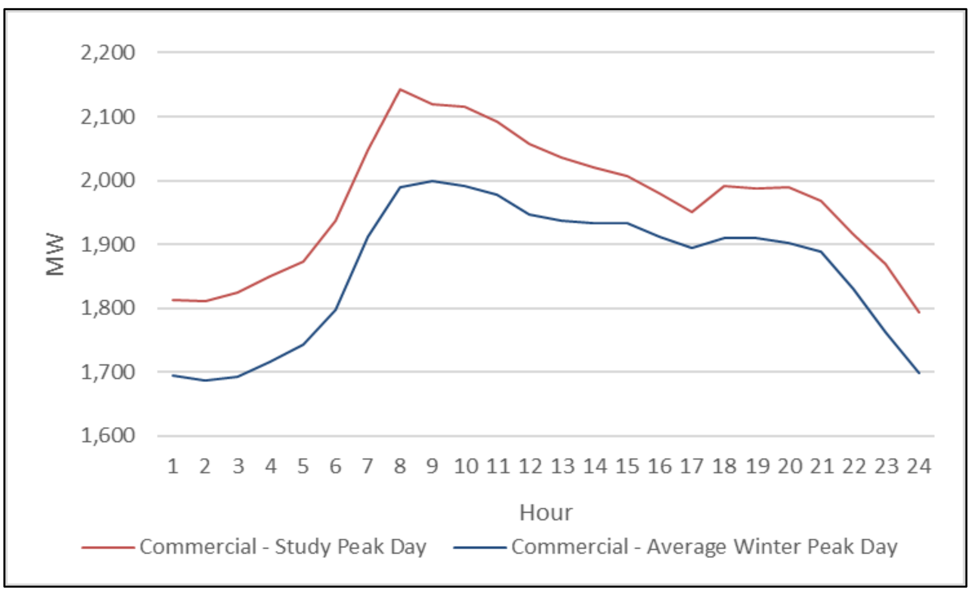
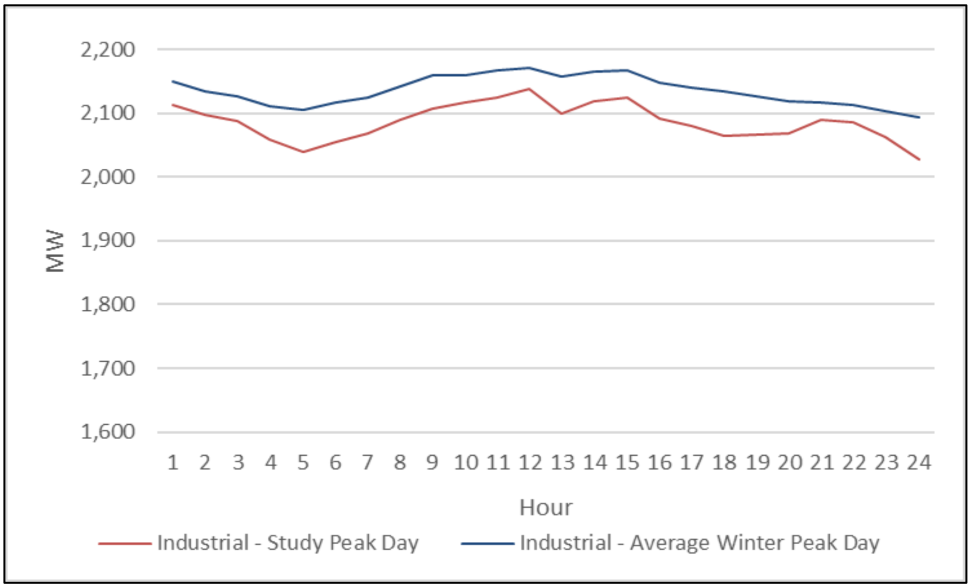


Figure 77 compares demand between the study peak day and the average winter peak days for Opt-I customers, showing slightly lower usage during our study peak day when compared to the average winter peak day, indicating that these customers may not be sensitive to weather events.

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



DEP

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

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

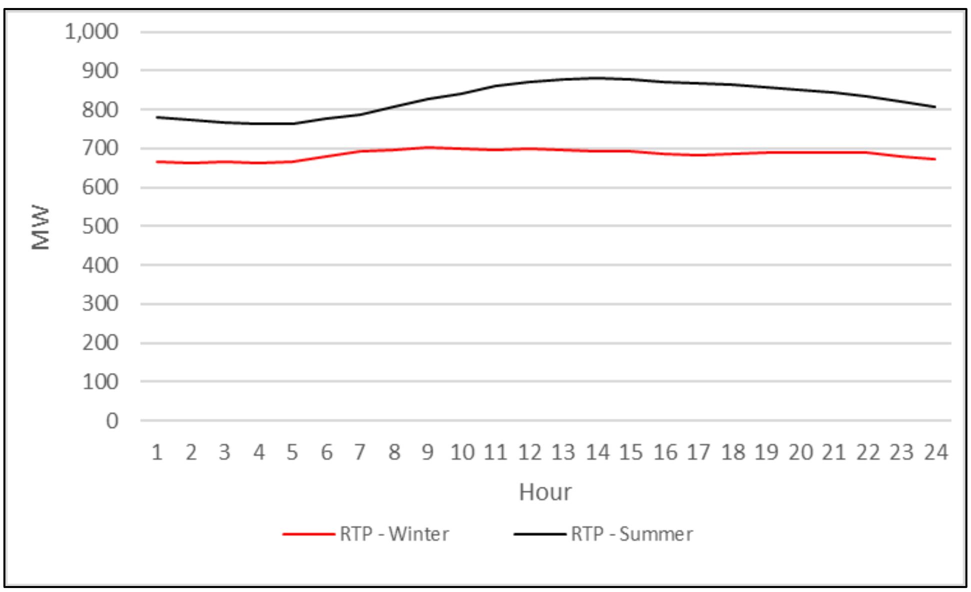


Figure 80 looks at the study peak day and adjusts the scale to emphasize the load shape profile during our study peak day, showing peak demand between 7:00 a.m. and 11:00 a.m., indicating some heating load. Like DEC, we analyzed the data underlying Figure 80 to define a heating load of 41 MW as shown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

Figure 84. DEP 2018 RTP Demand – Study Peak Day

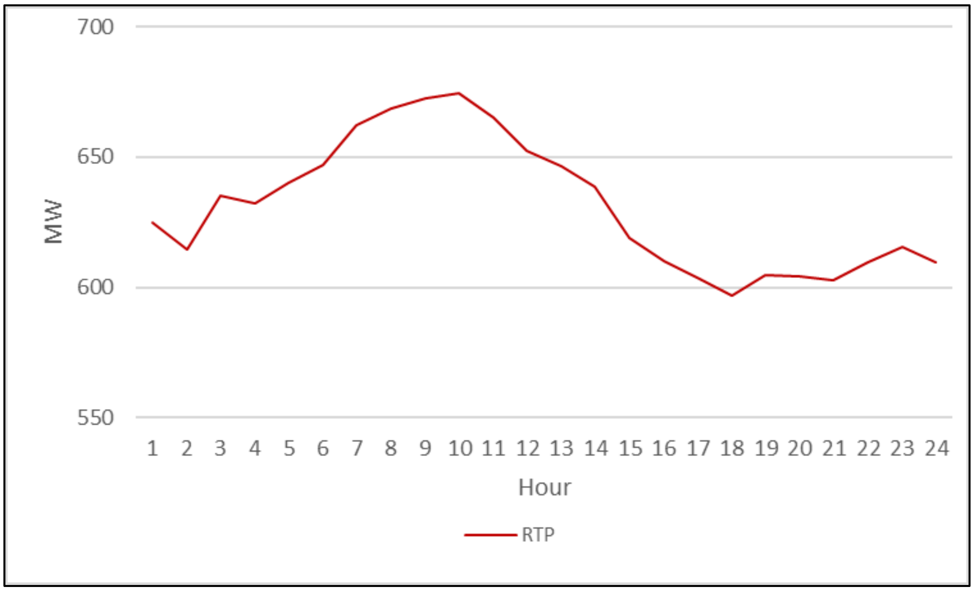


Table 47. DEP RTP Demand – Study Peak Day

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

Market Characteristics

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

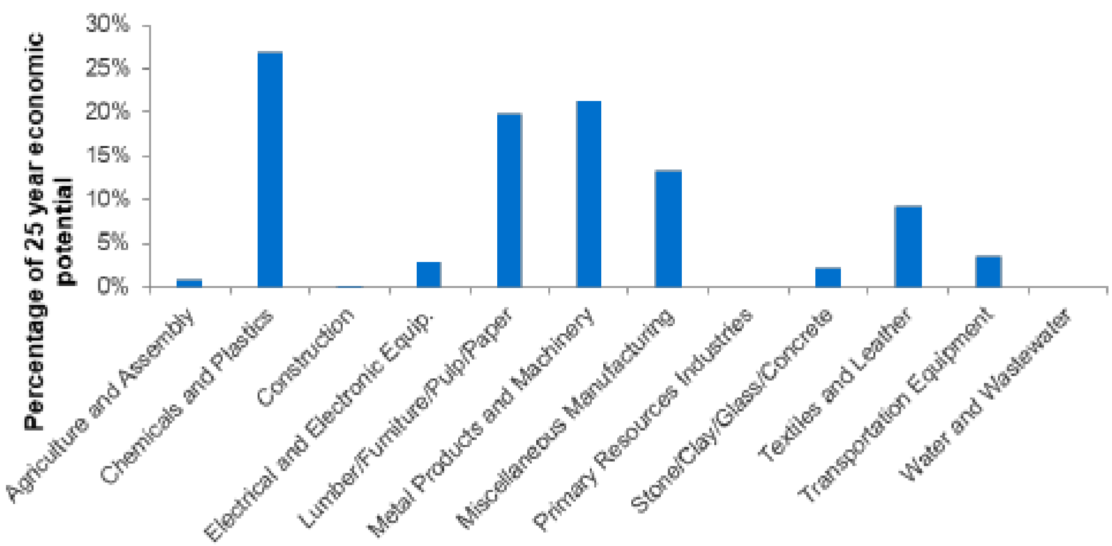
Table 48. Estimated Population of Large Buildings by Segment

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

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

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

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



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

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

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

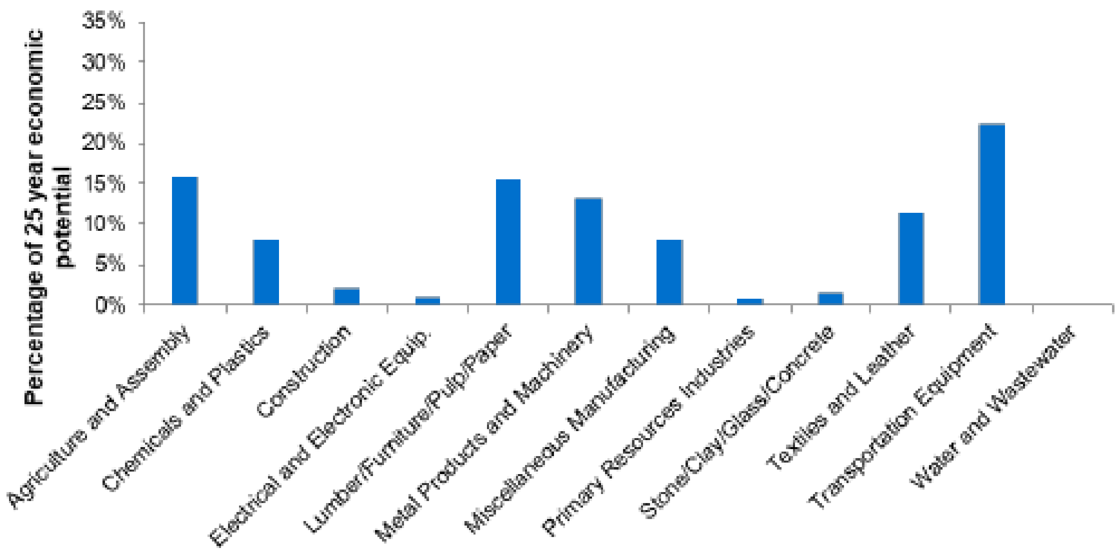
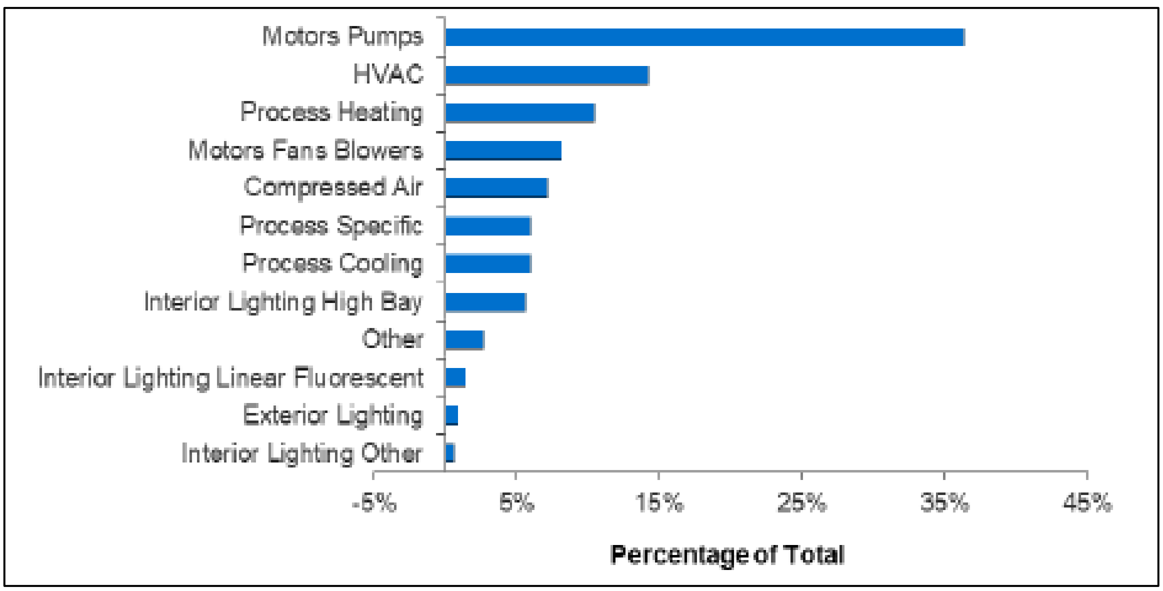


Figure 87. DEP NC Industrial Baseline Load Shares[48]



Solution Set Recommendations

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

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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

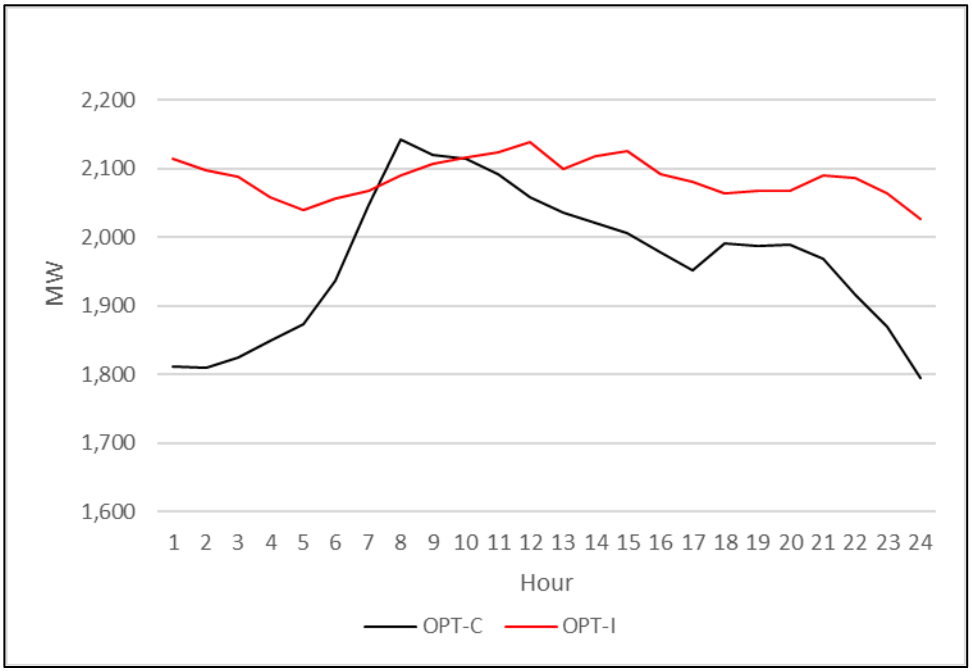


Table 49.DSM Capacity for PS and DRA

Primary Load Reduction Source	Participants	Capacity (MW@mtr) Summer	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 DEC - PS	OPCO - Program DEP - DRA	System DEC	System 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	Customers: % Viable	Customers: Viable Customers
DEC	LGS	11,431	40%	4,572
	OPTC	21,133	40%	8,453
	OPTI	1,642	10%	164
DEP	MGS	32,108	40%	12,843
	LGS	345	40%	138
Total		66,659	39%	26,171

Expanding the DSM Value Proposition

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

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

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

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

[50] Customers over 30,000 sq. ft. controllable via access to EMCS system

[51] KEY FILE - PowerShare and DRA Participant Info - July 2020 2020.07.07

[52] KEY FILE - DSM EE Opt Out_Apr20_Floyd (version 1).xlsb

LGS-RTP	90	80	113%

Reduce Participant Attrition

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

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

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

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

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

Leverage Emerging Duke Data Infrastructure to Manage DSM Operation Costs

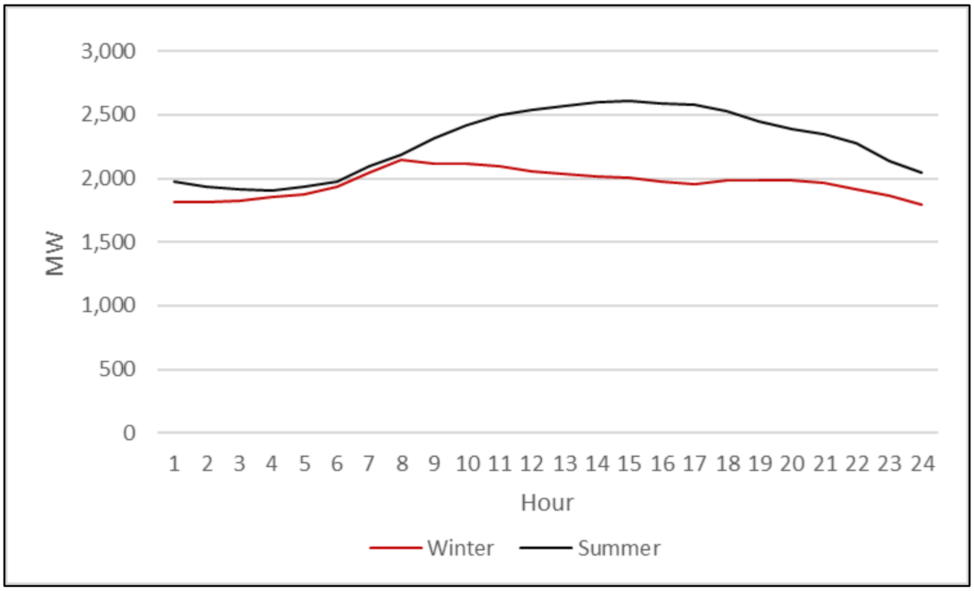
The proposed ADR design leverages Duke's expanding AMI and CIS/customer analytic capacity. This may help lower program costs in several ways, thereby enhancing cost effectiveness, including reducing the cost of identifying high potential sites and the use of normalized metered energy consumption to reduce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

Expand Both Summer and Winter Demand Response Capacity

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

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

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



Provide a Pathway for Expanded Use of Existing and Emerging Technologies

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

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

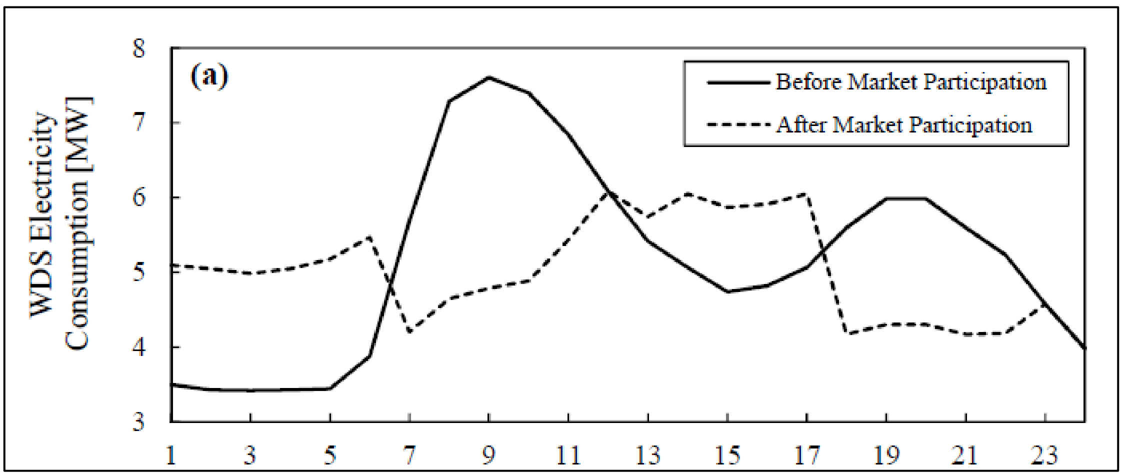
[54] 2018 SDG&E Demand Response Emerging Technologies Program semi-annual report accessed June 2020 at https://www.sdge.com/sites/default/files/regulatory/SDGE%20Semi%20Annual%20DR%20Emerging%20Tech%20Report%202018Q3.pdf

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

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

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

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



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

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

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

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

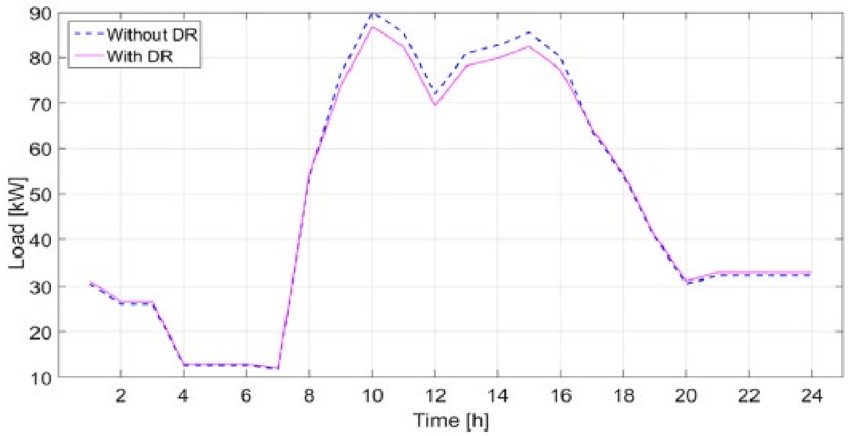
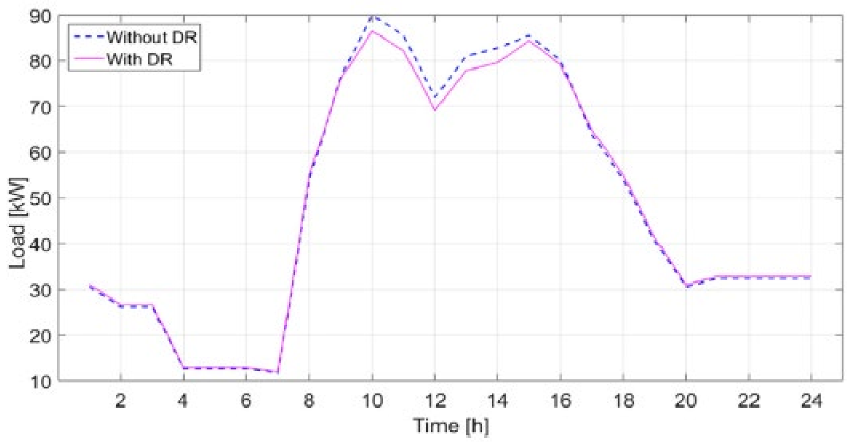


Figure 92. Shaved Curve of Load After RTP Implementation on an 11-bus MG



Key ADR Barriers

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

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

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

ADR Modelling Inputs

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

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

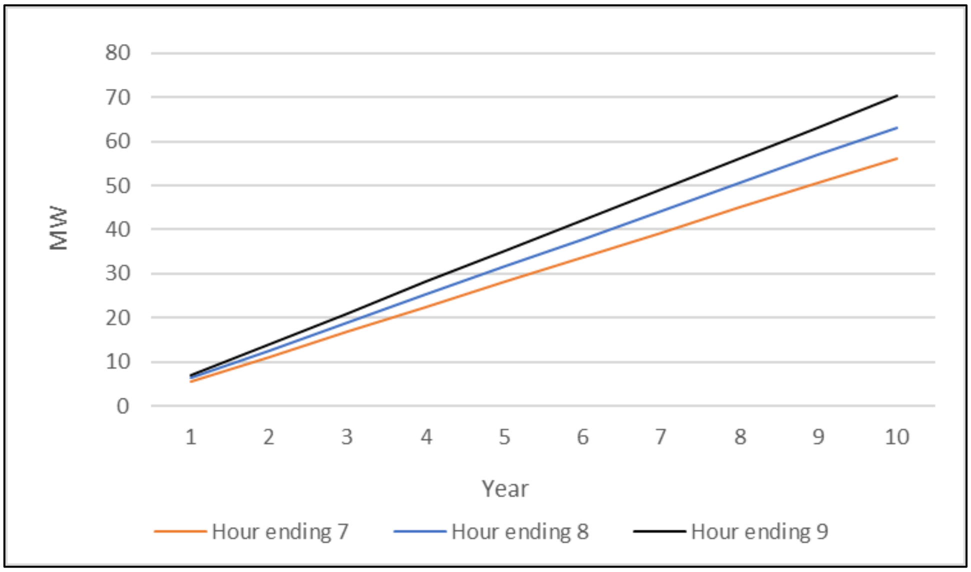
During the 3-hour event beginning at hour starting 7:00, some systems automatically adjust HVAC and light setpoints, savings will increase as facilities become more active with peak impact in hour starting 9:00. Table 54 shows our modelled ADR kW reduction occurring between 7 and 9, and likely kW increase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

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

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

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

Figure 93. 10-Year ADR Savings Forecast



Additional Large C&I Solution Set Consideration

Managed EV Charging

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

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

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

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

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

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

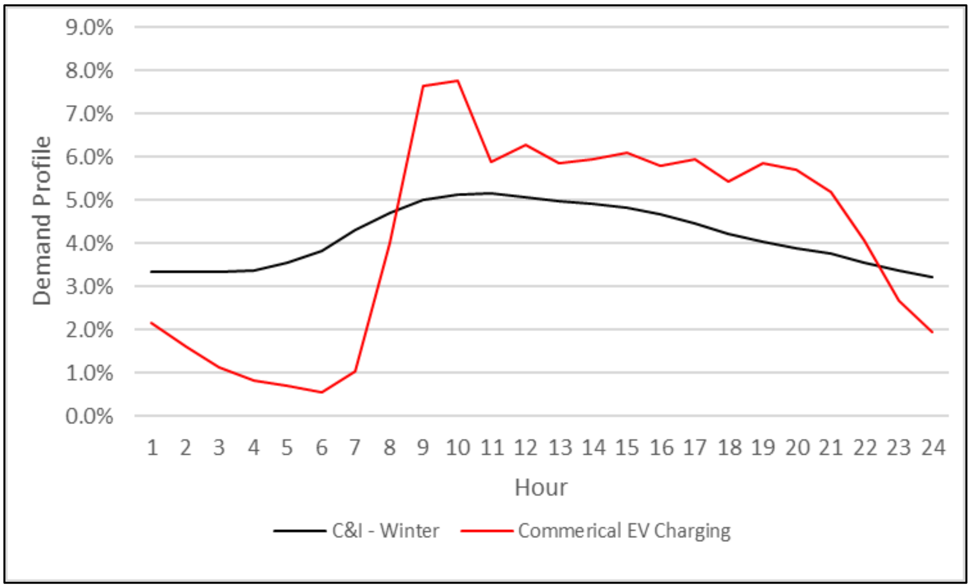
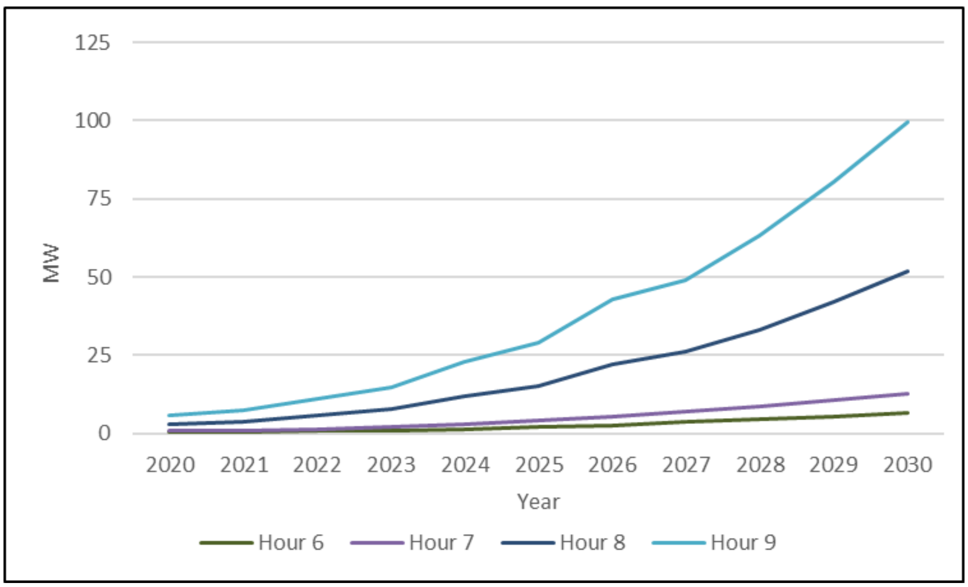


Figure 95. Public EV Charging Load Forecast by Morning Hour



Microgrids

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

7. Appendices

Appendix 1, Public Segment DSM Value

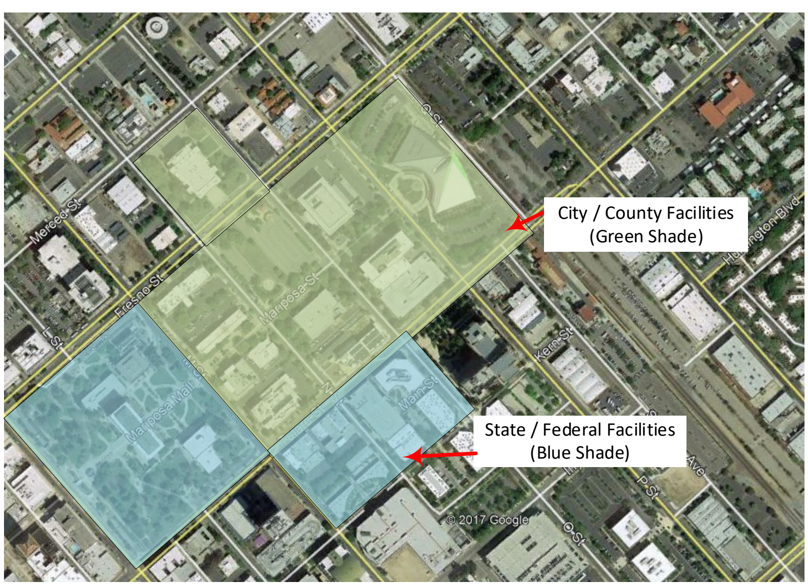
Consider that the public sector has various characteristics that support active load management and has provided market signals that align with an ADR solution:

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

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

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

Figure 96. Fresno Public Facility Microgrid Footprint



Appendix 2, Water Treatment Segment DSM Value

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

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

Overview

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

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

Equipment Controls

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

Aerators:

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

Disinfection Equipment:

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

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

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

Load Shed Strategies

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

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

Pumps:

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

Load Shift Strategies

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

Over-Oxygenation:

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

Storing Wastewater:

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

Process Rescheduling:

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

Anaerobic Digestion:

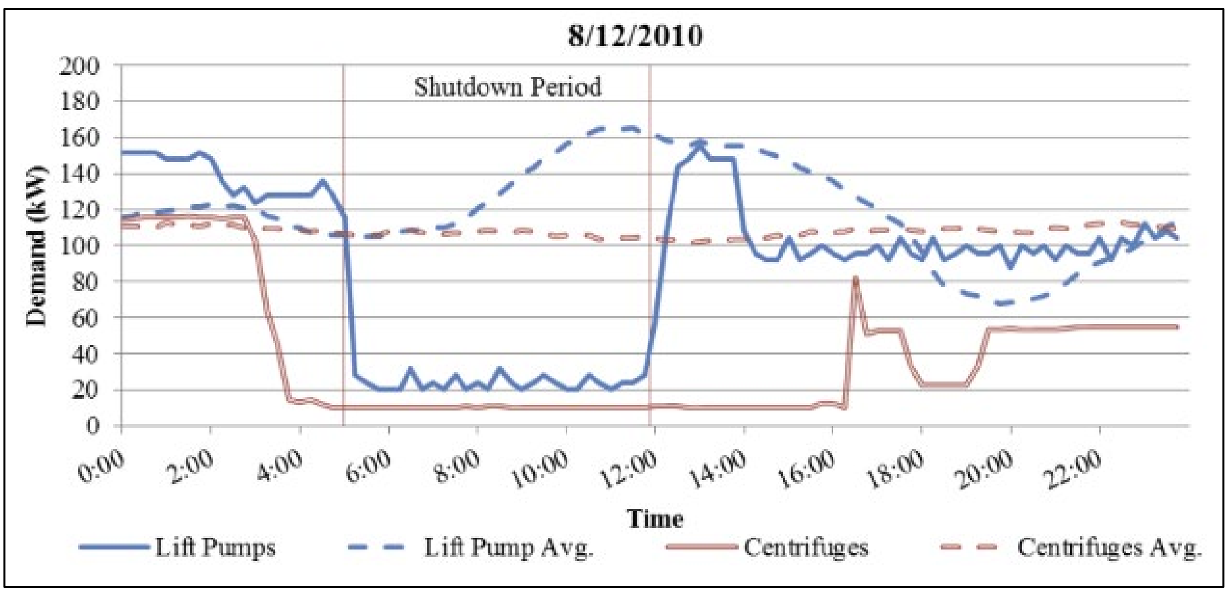
Using the biogas from anaerobic digestion to produce electricity can be an important demand response resource for the wastewater facilities.

Case Study

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

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

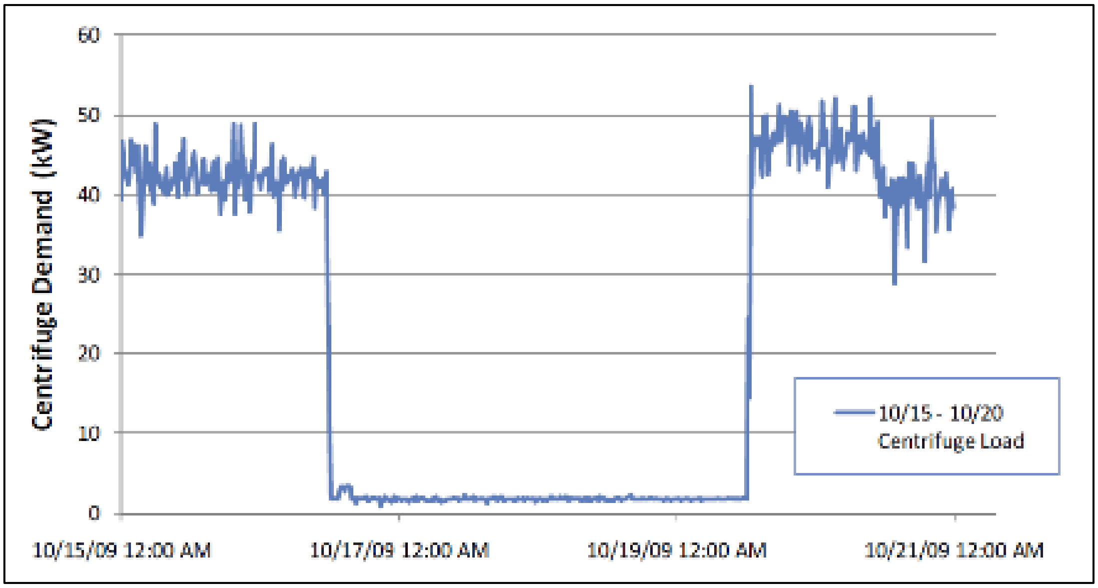
Figure 97. Shift Profile, Wastewater Treatment Plant Case Study #1



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

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

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



Appendix 3, DSM Program Structures and Types

Table 55. DSM Program Structures

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

Table 56. DSM Program Types

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