SEASONAL ELECTRIC DEMAND IN THE SOUTHEASTERN UNITED STATES

JOHN D. WILSON, MAGGIE SHOBER

JOHN D. WILSON
Research Director
Resource Insight, Inc.
MAGGIE SHOBER
Director of Utility Reform
Southern Alliance for Clean Energy

cleanenergy.org
Southern Alliance for Clean Energy

EXECUTIVE SUMMARY

The Southeast is widely perceived as a summer peaking region, though many of its utilities experience winter peak events. This analysis summarizes trends in seasonal demand peaks using data from 1999 through 2018 and provides commentary on how this analysis may or may not inform utility load forecasting and resource planning moving forward. Even though the Southeast peaks in both summer and winter, the summer season likely remains the most constrained in terms of generation resources.

SOUTHEASTERN REGIONAL ELECTRIC DEMAND TRENDS

From a Southeastern regional perspective, six important trends can be observed.

- The Southeast's peak electric load has shifted from a period of growth to decline.
- The Southeast is now a dual peaking region due to declining summer peaks.
- Even though the Southeast is a dual peaking region, the vast majority of peak hours occur during the summer.
- Winter peak variability is higher than summer peak variability, but there is no evidence of an increase or decrease to seasonal peak variability.
- Southeastern utilities appear to have adjusted forecast methods to reflect a weaker relationship between economic growth and load growth.
- Southeastern utilities are still overestimating future peak demand for electricity.

UTILITY ELECTRIC DEMAND TRENDS

While there are many individual utility trends, several key differences from the regional perspective can be observed in these data.

- While the Southeast region is in a period of peak load decline, it is not easy to discern a clear trend in individual utility peak loads. Year-to-year weather fluctuations may mask a trend.
- Utility trends are, however, evident in electric power consumption. Some utilities have experienced growth at rates that may exceed 2% annually. In contrast, some other utilities have experienced declining loads.
- The Southeast is a dual peak region, and utility systems are evenly balanced between winter and summer peaking systems. Eight appear to be winter peaking, six appear to be dual peaking, and eight appear to be summer peaking. Winter peaks are more common in recent years than in the earlier years of our 20-year analysis.
- Winter peaks at all utilities are less frequent than summer peaks.
- Summer peak events tend to be of similar length (on average, under 5 hours) and have a similar load shape, although a few utilities tend to have longer duration peak events of up to 12 hours.
- For most utilities, winter peaks are of shorter duration than summer peaks. However, the most strongly winter peaking systems also have occasional long duration peak events of 14 hours or more and occasionally more than 20 hours.

- Utilities vary in the degree of coincidence with the overall regional peak. Several large utilities are closely associated with regional peak events, but others tend to be more seasonal in their association. Peninsular Florida utilities require special consideration due to the pattern of coincidence and the limitations on transmission connections to the rest of the Southeast.

COMMENTARY

Utility planning for resource acquisition and independent power development are important activities that determine the cost and reliability of power in the Southeast. Forecasts for peak demand play a key role in this utility planning process.

It is surprising just how steady seasonal peak demand characteristics have been over the past 20 years, even while there have been notable shifts from growth to flat or declining annual energy consumption. For example, summer and winter peak durations appear similar now to two decades ago.

The reliability risks to power and transmission resources are associated not only with demand during the largest peak event, but with the number of hours that a system is at or near peak demand. There are about 20 times as many summer peak hours than winter peak hours, thus the cumulative reliability risk associated with thermal power plant failures is likely higher in the summer season as a whole for all (or nearly all) utilities in the Southeast.

There does not seem to be support in the data for suggestions by some utility planners that reliability risk is increasing in the winter due to increasing variability in winter peaks. Utility load data do not demonstrate a clear trend towards increases in winter peaks, either at the regional level or at the individual utility level. Some utility planners have also assigned reliability risk to an increased reliance on solar power. Although solar power's generation profile is poorly aligned with winter peaks, other resources may be more reliably available. For these reasons, reliability risk in the winter may not be increasing as much as has been implied.

The fact that Southeast regional trends are not shared among all utility systems is a significant finding in and of itself. Seasonal peaks are variable across utility systems in the Southeast and do not appear to follow trends related solely to climate, technology, or other demographics. Utility planners and regulators should consider the context provided by regional data, should apply a high degree of scrutiny to trends that may initially appear significant, and avoid being misled by statistically insignificant trends.

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INTRODUCTION

The Southeast is widely perceived as a summer peaking region, though many of its utilities experience winter peak events. Due to high use of electricity for space heating, residential and small commercial resistance heating loads, including backup heating installed in heat pump units, often drive these winter peak events. Understanding where winter peak events may occur, and identifying energy efficiency, demand response, and distributed energy resource solutions may help address these issues.

Peak demand is important to electric utilities and their regulators because high levels of demand are associated with greater system reliability risks and thus drive investment in power plants, transmission, and (to a lesser extent) distribution systems. If anticipated seasonal peaks are in the summer, winter, or potentially either season, then utility investment decisions will focus on resources that perform in its peak demand season.

Utilities often describe the planning process around being winter, summer, or dual peaking, but there is no single regulatory filing in which utilities declare a season, nor is there a widely accepted method for making such a determination. If a utility's anticipated weather-normalized peak[1] for the summer exceeds that for the winter, then it could be a summer peaking utility. But what if a utility anticipates that in a median year it will be summer peaking, but in an extreme-weather year it is highly likely to be winter peaking?

In order to look at both "normal" and "extreme" weather years, in Table 1, we classify utilities as winter, dual, or summer peaking using three measures: winter peak hours, winter peak events, and a seven-year winter-to-summer peak ratio. The classification order reflects an aggregated measure, but the measure is somewhat arbitrary and thus the specific ranking should not be closely relied upon.

[1] A forecast, weather-normalized peak is essentially the median peak, i.e., the actual peak is equally likely to exceed or fall short of the forecast.

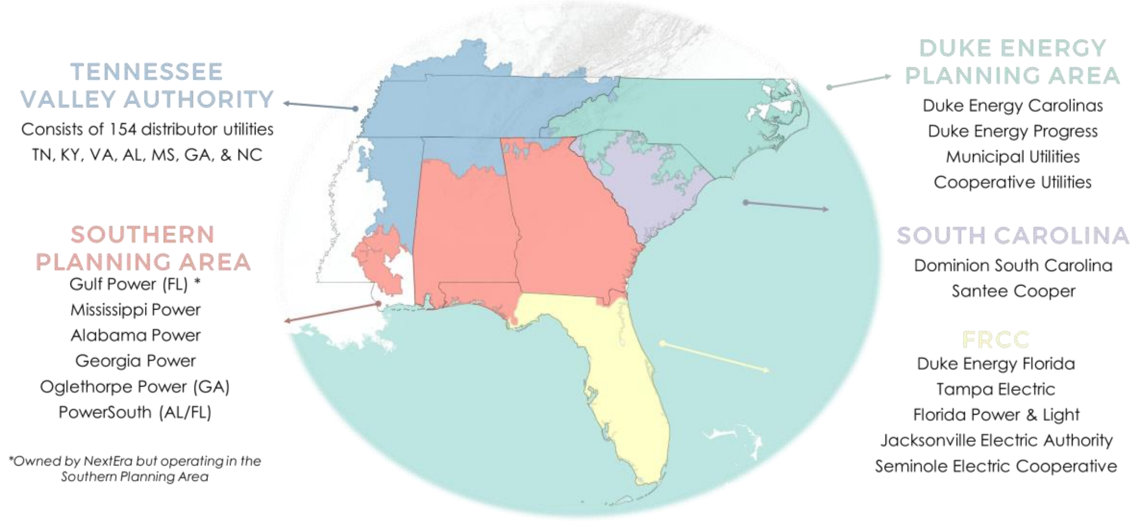
TABLE 1: SEASONAL ELECTRIC DEMAND TENDENCIES OF SOUTHEASTERN UTILITY SYSTEMS

WINTER PEAKING	DUAL PEAKING /TRANSITIONAL	SUMMER PEAKING
• PowerSouth Energy Cooperative • Santee Cooper • Seminole Electric Cooperative • Duke Energy Progress, including Greenville Utilities Commission • Tennessee Valley Authority (TVA) • JEA • Mississippi Power • Lakeland Electric	• Duke Energy Florida • Gulf Power • Alabama Power • Duke Energy Carolinas • Dominion Energy South Carolina (DESC) • City of Tallahassee	• Tampa Electric • Florida Municipal Power Agency (FMPA), including City of Homestead • Oglethorpe Power • Georgia Power, including Southern Power • Municipal Electric Authority of Georgia (MEAG) • Gainesville Regional Utilities (GRU) • Orlando Utilities Commission (OUC), including City of St. Cloud • Florida Power & Light (FPL)

The Southeast region as a whole appears to be a dual peaking region. This conclusion is based on regional coincident peak data, using aggregated hourly load data from the Southeast's utility systems. Specific utility classifications do not follow an obvious geographic or climate pattern, but rural utility systems appear to be overrepresented in the winter peaking group.

The 22 utility systems analyzed in this report are actually planning authorities designated by the Federal Energy Regulatory Commission (FERC). Planning authorities often include multiple utilities. In four cases, we combined reports from two planning authorities into a single aggregated utility system. The utility systems listed above are believed to include 100% coverage of utility electric demand in Alabama, South Carolina, Georgia and Florida, as well as partial coverage of Kentucky, Tennessee (>99%), Mississippi, North Carolina and Virginia (<1%). The service area of these 22 utility systems is illustrated in Figure 1.

FIGURE 1: SOUTHEAST ELECTRIC UTILITY SYSTEMS



BACKGROUND AND METHOD OF ANALYSIS

The premise of this analysis is that peak demand is important to electric utilities and regulators because high levels of demand are associated with greater system reliability risks and thus drive investment in power plants, transmission, and (to a lesser extent) distribution systems. In our experience, utilities typically evaluate peak demand in two ways (using historical or forecast data, for example). Most commonly, a simple annual or seasonal peak demand trend is discussed. In more detailed studies, utilities often look at multiple hours per year, such as a "top 100 hours" analysis.

While we agree with the usefulness of the first approach, the second approach comes with some issues. Some years have more extreme weather or demand conditions than others. But if a utility uses a "top 100 hours" method to examine multiple years of data, then it effectively weights less extreme peak hours (from a less extreme year) equally with more extreme peak values (from a more extreme year). As noted by Mills and Rodriguez, "The [capacity credit] using all hourly data across 11 years at once is arguably the most accurate way to estimate the overall contribution of a resource toward reliability."[2]

To overcome this limitation, we select peak hours over a long-term dataset. Similar to Mills and Rodriguez, our method is patterned after the method utilities use in reliability studies, in which hours with greater reliability risk are used to determine the optimal reserve margin for the system. Since reliability risk metrics are not often publicly available, we use an equal weighting of the top 1.1% demand hours in a long-term dataset, as described below.

[2] Andrew D. Mills and Pia Rodriguez, Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities, Lawrence Berkeley National Laboratory (October 2019).

We obtained data from Federal Energy Regulatory Commission (FERC) Form 714 and from utilities, for years from 1999-2018.[3] We used two measures: prior-year seasonal peak forecast and actual hourly system load data for the planning areas listed in Table 1.

Actual hourly system load data are not adjusted for demand-side or distributed energy resources. To the extent that they exist and are operating, net metered generation and demand response programs would tend to reduce peak demand.

The top 1.1% peak demand hours were selected for each utility, and for the Southeast as a region, based on our calculation of system load factor.[4] The load factor is calculated as the actual hourly demand divided by the annual peak forecast. For example, if system demand for an hour is 900 MW, and the utility's forecast annual peak demand for that year is 1,000 MW, then the load factor for that hour would be 90%. This method normalizes the 20 years of data in the study for system growth or contraction.

We decided to use a load factor based on the year-ahead forecast[5] because the year-ahead forecast is the best publicly-available indication of what the utility's planning experts believe the weather normalized peak would be in each year.

A mismatch in the regional peak demand data is unavoidable due to the data characteristics. The actual seasonal peaks reported for the entire Southeast region are a coincident peak, as we aggregated the data on an hourly basis and then determined the actual peak hours for the region. But the benchmark year-ahead forecast value is the sum of the seasonal peaks reported by the planning areas, and is thus a non-coincident peak forecast. This mismatch (coincident peaks for historical vs non-coincident peaks for forecast) does not appear very impactful to our findings.[6]

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[3] In the case of small data gaps, we used linear extrapolation to estimate missing values. After completing this effort, our database lacked some data for three utilities: Seminole (2003), Orlando (2003 and 2004), and SCE&G (2004). The database also includes data for 1998, which is used in limited circumstances due to quality concerns.

[4] In this respect, our method differs from Mills and Rodriguez, who simply select the top 1.1% of hours. Selecting the top 1.1% hours over two decades would tend to overemphasize years with higher overall load and demand.

[5] Year-ahead forecasts (i.e. the forecast for 2010 released in 2009, the forecast for 2011 released in 2010, etc.) summed across the Southeast to get a non-coincident peak.

[6] There are two reasons the mismatch is not likely to have an impact. First, none of the analysis directly compares forecast peak to actual peak values. Second, the main application for the forecast peak value is as a benchmark across years for establishing the top 1.1% hours. While these benchmarks would be somewhat lower than they would have been if calculated using a coincident peak, the load factor ranking in any given year would be unchanged. If coincident peak forecasts were available, the multi-year ranking could change if the ratio of coincident to non-coincident peaks varied over time.

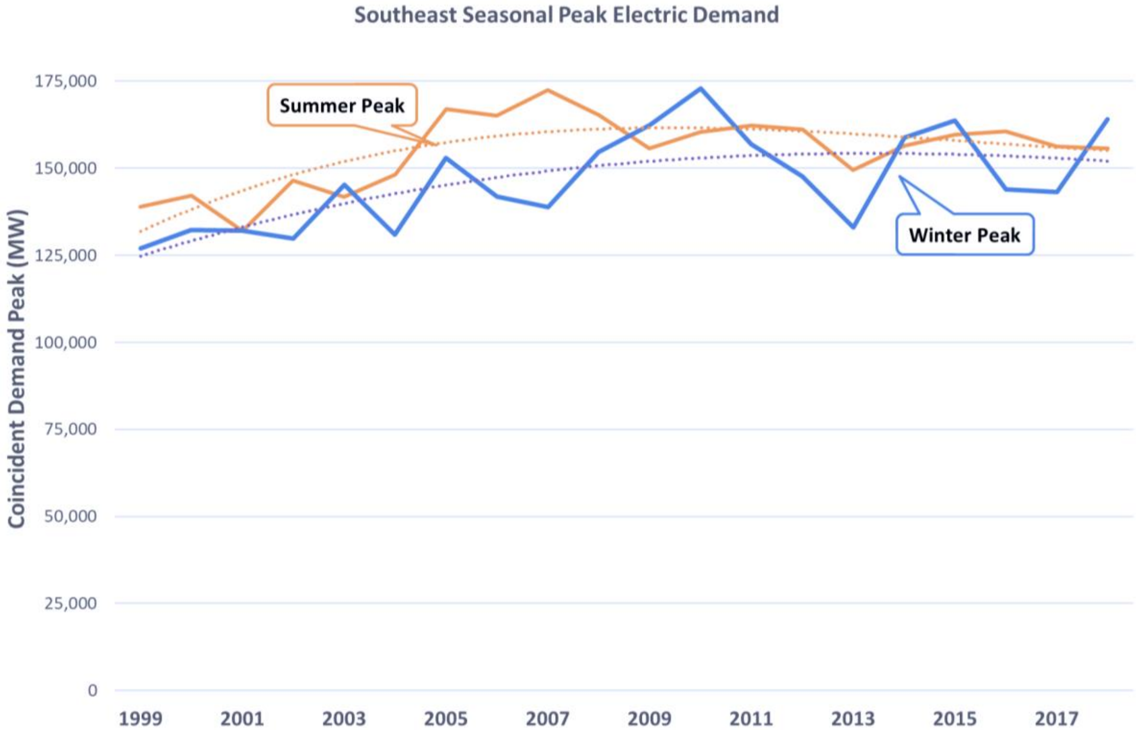
SOUTHEASTERN REGIONAL ELECTRIC DEMAND FINDINGS

OVERALL PEAK DEMAND HAS BEEN DECLINING SINCE AT LEAST 2010: The Southeast region's peak electric demand was increasing until sometime in the 2008 to 2010 time-period. (It is difficult to assign a specific date due to weather-driven variability.) As illustrated in Figure 2, since at least 2010, the region's peak electric demand appears to be declining.

WINTER PEAKS ARE CATCHING UP TO SUMMER PEAKS: The Southeast has historically been characterized as a summer peaking region. As illustrated in Figure 2, over most of the past twenty years, the region's winter peaks have averaged about 95% of the corresponding summer peak.

In seven of the past 20 years, the region peaked during the winter season. Of these seven peaks, five were in the past ten years. The Southeast's all-time maximum hourly demand occurred in a winter month, but was only slightly higher than the region's highest coincident summer peak.[7] For these reasons, as well as other evidence in this report, the Southeast is best characterized as a dual peaking region.

FIGURE 2: SEASONAL COINCIDENT PEAKS IN THE SOUTHEAST, 1999-2018



Notes:
Trendlines are third order polynomial equations. R^2 for summer peak trend is 68% and for winter is 60%.
Data for 1-2 small utilities are unavailable or incomplete for 1998, 2001, 2003 and 2004. For unavailable data, a proxy value based on adjacent years data is assumed, with a maximum proxy value adjustment of 4,500 MW in 2004.

Source: Utility data filed on FERC Form 714 for 1998-2018, or provided directly to SACE by utility staff.

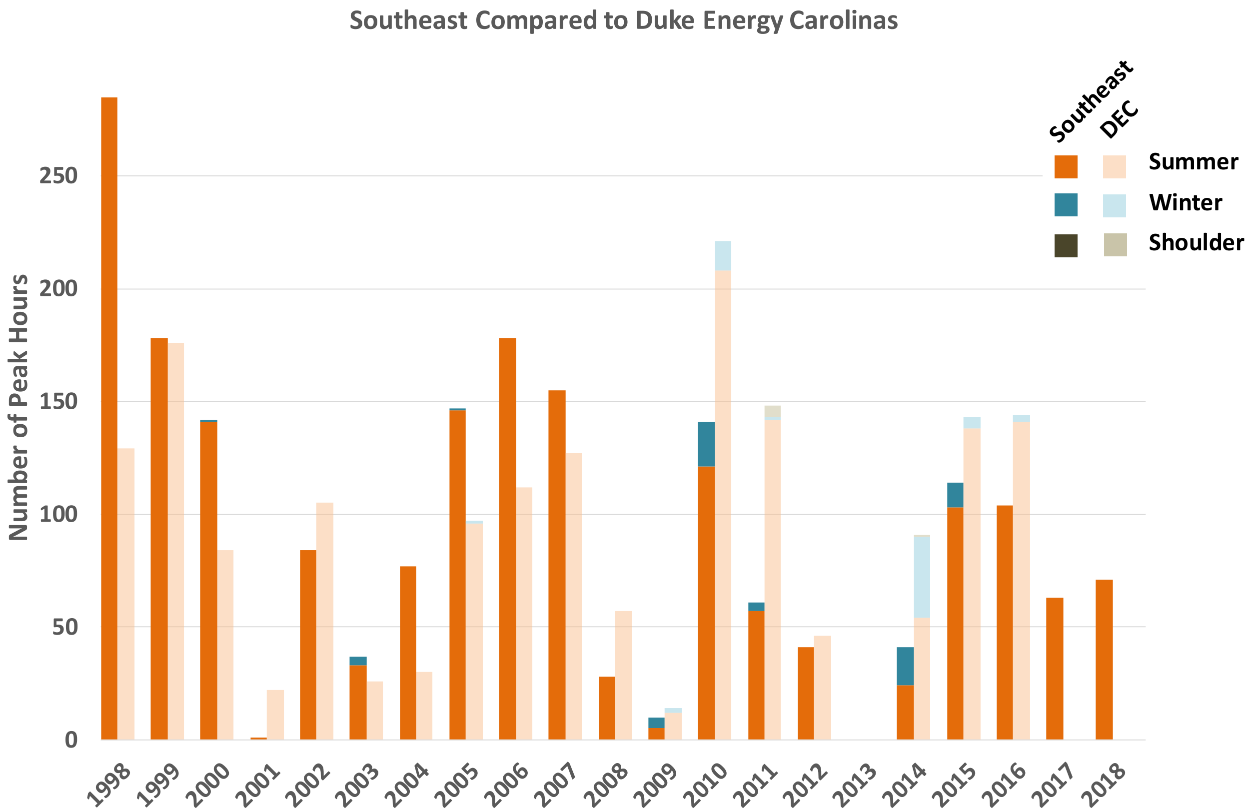
[7] All-time coincident peak of 172,900 MW occurred on January 11, 2010; all-time coincident summer peak of 172,517 MW occurred on August 9, 2007.

Since 2010, the trendline illustrated in Figure 2 suggests that the summer peak has declined by about 5%. However, during that same time the winter peak trend is flat. Over the 1999-2018 time period, the Southeast's summer and winter peaks have converged: winter peaks tended to be about 90% of summer peaks in the early years of the dataset, but the recent decline in summer peaks means that winter peaks are now about 98% of summer peaks.

PEAK HOURS MAINLY OCCUR IN SUMMER, BUT WINTER PEAK HOURS ARE BECOMING MORE FREQUENT: Even though the annual winter peaks average about 95% of the corresponding summer peak, utility systems experience summer peaks far more frequently than winter peaks. As illustrated in Figure 3, only about 5% of peak hours (the top 1.1% hourly loads over the 20 year period ranked by load factor) occur during the winter. Very occasionally, in years such as 2014, a large share of a year's peak hours can occur during the winter.

Corresponding to the narrowing gap between summer and winter peaks discussed above, the number of winter peak hours is increasing: 86 of the 97 winter peak hours in the Southeast occurred during the 2010-18 timeframe. However, there is no indication that winter peak hours will become as common as summer peak hours in the near future, as even over the past decade, 90% of peak demand hours occurred during the summer.

FIGURE 3: PEAK DEMAND HOURS PER YEAR, BY SEASON, 1998-2018



Source: Utility data filed on FERC Form 714 for 1998-2018.

Another point illustrated in Figure 3 is that the seasonal distribution of peak hours can differ among utilities and between a particular utility and the Southeast region as a whole. In 2011, for example, Duke Energy Carolinas (DEC) experienced an above average number of peak hours, even though the Southeast region experienced below average peak hours.

WINTER PEAKS ARE MORE VARIABLE THAN SUMMER PEAKS, BUT THERE IS NO TREND: Winter peaks appear to be more variable than summer peaks. Over the past two decades, the average winter peak is 95% of the corresponding summer peak and this difference varies between 81% and 108%. There is no apparent trend in the variability of regional winter peaks: the data do not indicate that winter peaks are becoming more or less variable relative to summer peaks.

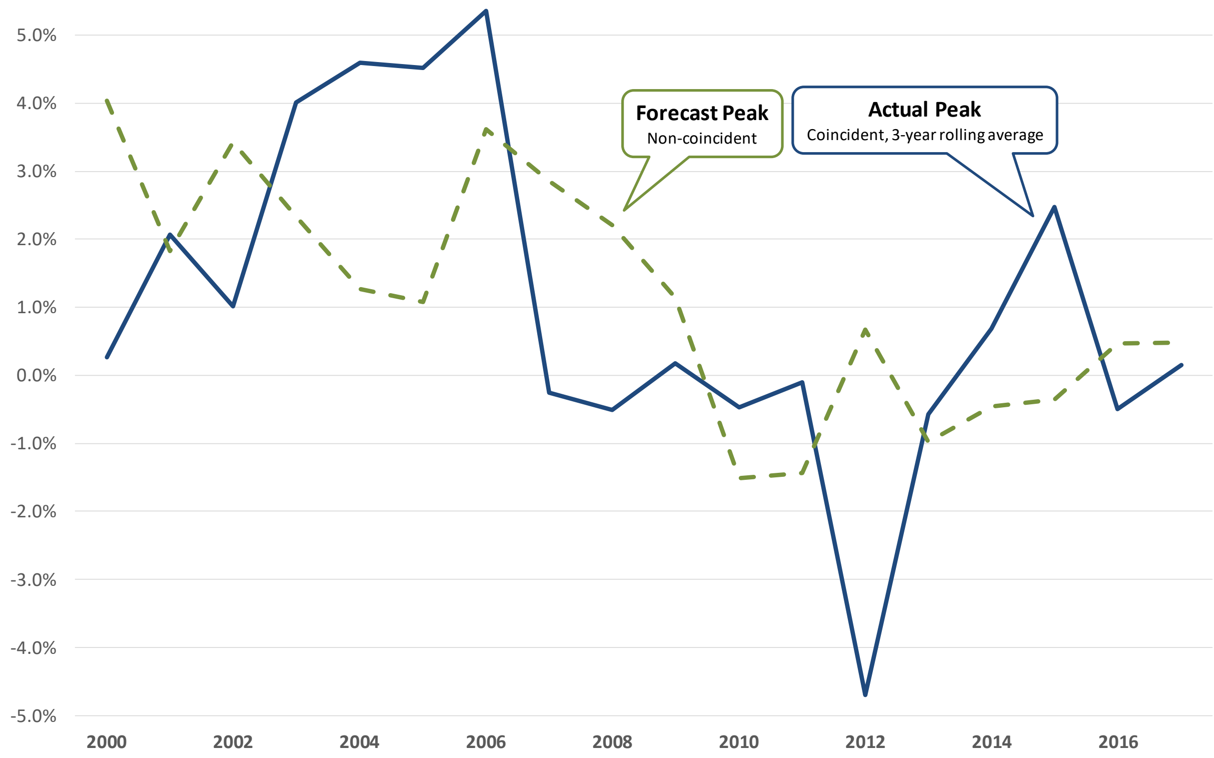
Some have suggested that winter peaks are becoming more variable due to recent "polar vortex" events, others have linked variability to an increase in heat pump technology (which usually relies upon high-demand resistance heating elements when cold weather renders heat pump technology inadequate). The data do not support an increase in regional load variability during the winter, but either of these explanations could be relevant to the convergence of summer and winter peaks.

Much of the variability in winter peaks is well explained by basic statistics. The relatively small number of winter peak hours compared to summer peak hours results in a naturally more variable peak. Out of 1,903 peak hours studied for the Southeast region, only 97 occurred during the winter. In 11 of 20 years, no peak hour occurred during the winter. In contrast, summer peak hours occurred every year, and overall summer peak demand has not strayed far from the trend line, with the exception of the significant spike in the 2005-2007 time period shown in Figure 2. In fact, it is statistically improbable that the 97 winter peak hours would be distributed evenly across the years, or even that the nine years with any winter peak hours would be distributed consistently across the two decades.

SHORT-TERM UTILITY FORECASTS HAVE IMPROVED: The utilities' year-ahead planning forecasts[8] have only roughly reflected actual peak trends. The difference between year-ahead planning forecasts and actual peaks should be dominated by weather effects, since the utility should, in theory, have a good idea of customer demand trends in the short run. However, the inability of utility planners to anticipate economic changes is also evident in these data.

[8] Year-ahead forecasts (i.e. the forecast for 2010 released in 2009, the forecast for 2011 released in 2010, etc.) summed across the Southeast to get a non-coincident peak.

FIGURE 4: SOUTHEAST ANNUAL PEAK GROWTH RATE, ACTUAL VS FORECAST, 1999-2018



Source: Utility data filed on FERC Form 714 for 1998-2018.

As shown in Figure 4, in the mid-2000s, Southeastern utilities predicted slow growth in annual peaks, when in fact they grew rapidly. Reacting to this growth, utilities increased their forecasts, only to be blindsided by the Great Recession (which began in 2008). However, during the past 6 years, Southeast utilities' year-ahead forecasts are somewhat aligned with actual peak growth rates, with the best match occurring during the past 7 years, as shown in Table 2.

TABLE 2: AVERAGE ANNUAL GROWTH RATE, ACTUAL VS YEAR-AHEAD FORECAST, SOUTHEAST UTILITIES, 2000-2018

	ACTUAL ANNUAL PEAK (COINCIDENT)	FORECAST ANNUAL PEAK (NON-COINCIDENT)
2000 – 2005	3.3 %	2.3 %
2006 – 2011	- 0.4 %	1.1 %
2012 – 2018	0.3 %	- 0.2 %

Economic growth has rebounded since the Great Recession but annual peak load growth in the Southeast has not returned to pre-recession levels. Southeastern utilities appear to have adjusted forecast methods to reflect a weaker relationship between economic growth and load growth.

LONG-TERM UTILITY FORECASTS CONTINUE TO OVERESTIMATE PEAK DEMAND: Although long-term forecasts have also improved, Southeast utilities continue to overestimate future demand. Utility forecasts have financial impacts on customers because they drive resource planning and generation procurement decisions. Systematically overestimating peak demand can result in unnecessary acquisition of generation and transmission resources.

As shown in Table 3, Southeast utilities do systematically overestimate peak demand. Table 3 summarizes the regional total for utility system forecasts filed in 2006-13 for the non-coincident peak demand five years later, in 2011-18. The five-year forecasts overestimated regional demand by an average of 8%.[9] However, there does appear to be a trend towards improving forecasts, with the average error declining by 1% per year.

TABLE 3: FIVE-YEAR FORECAST VS ACTUAL, SOUTHEAST UTILITIES, 2011-2018

	FORECAST PEAK (GW)	ACTUAL PEAK (GW)	FORECAST ERROR
2011	150.7	136.6	10 %
2012	189.9	170.6	11 %
2013	185.0	169.3	9 %
2014	181.6	167.1	9 %
2015	182.9	168.0	9 %
2016	180.5	169.4	7 %
2017	178.6	168.0	6 %
2018	176.7	167.9	5 %
AVERAGE			8 %
TREND			- 1 % / year

SOUTHEASTERN UTILITY ELECTRIC DEMAND FINDINGS

UTILITY TRENDS IN OVERALL DEMAND VARY WIDELY: Seasonal electric demand for individual Southeastern utilities is different than for the region as a whole. For example, as illustrated in Figure 3 earlier, DEC experienced more peak load hours in 2010 and 2011 than did the Southeast region (as a whole), but fewer such hours in 2007 and 2012. Considering trends since the Great Recession, it does not appear that there has been sufficient time for definitive trends in seasonal electric demand to be established for individual utilities.

[9] The five year ahead forecasts for all balancing authorities are available for 2011-18, except for MEAG. Only three utilities' five year ahead forecasts were readily available for 2010. Forecast availability for prior years is more difficult to obtain. The Southeast total is the sum of the utilities reporting data, and thus represents non-coincident peaks for both forecast and actual demand.

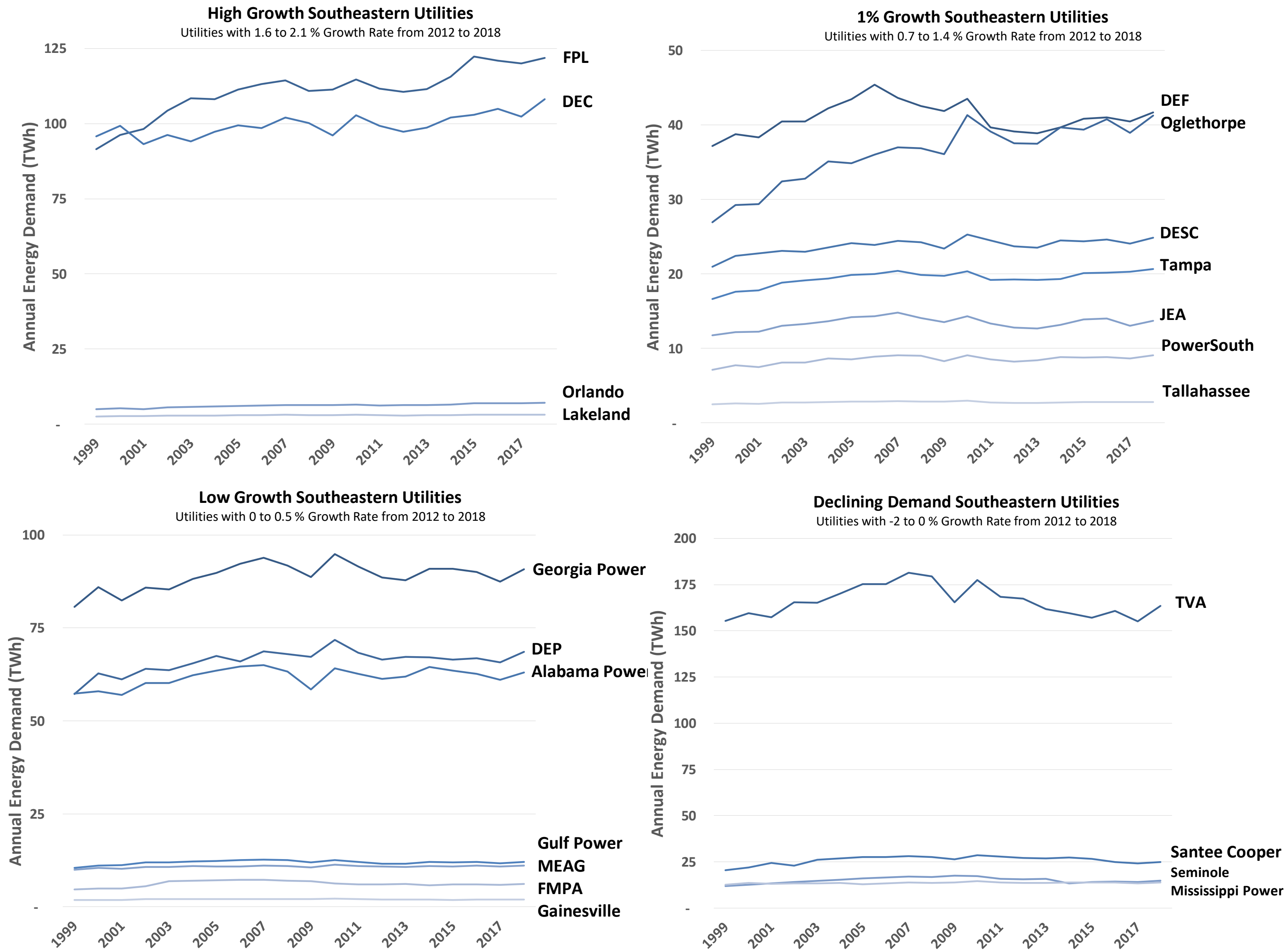
For some utilities, statistically meaningful trends in summer demand are present in the data. However, such trends are not apparent in the winter. For example, TVA shows a summer demand trend for 2012-2016 of -2.1% and no statistically significant winter trend. Due to the lack of definitive trend data, this report does not include trend data for specific utilities.

Nonetheless, with respect to annual energy consumption (retail sales plus losses), statistically meaningful trends do emerge. As illustrated in Figure 5, some utilities in the Southeast are showing relatively high growth of around 2% per year from 2012-18, while energy consumption at others is declining modestly. For the 2012-18 time period, annual energy consumption grew at about 0.5% per year.

As with the trend in regional peaks, the Great Recession marks a significant turning point for nearly every utility. On average, the annual change in energy consumption dropped by 1.6% after the Great Recession.[10] Only DEC showed an increased rate of growth, increasing from a 0.6% to a 1.6% annual growth rate. Among the larger utilities, the biggest inflection was at TVA, which decreased from a 1.9% growth rate to a 0.5% attrition rate.[11]

[10] Comparing the 1999-2008 time period to the 2012-2018 time period, thus mostly excluding the Great Recession impacts.
[11] One factor in TVA's attrition rate is the closure of a major customer (a uranium enrichment plant) in 2013.

FIGURE 5: ANNUAL POWER CONSUMPTION BY UTILITY, 1999-2018

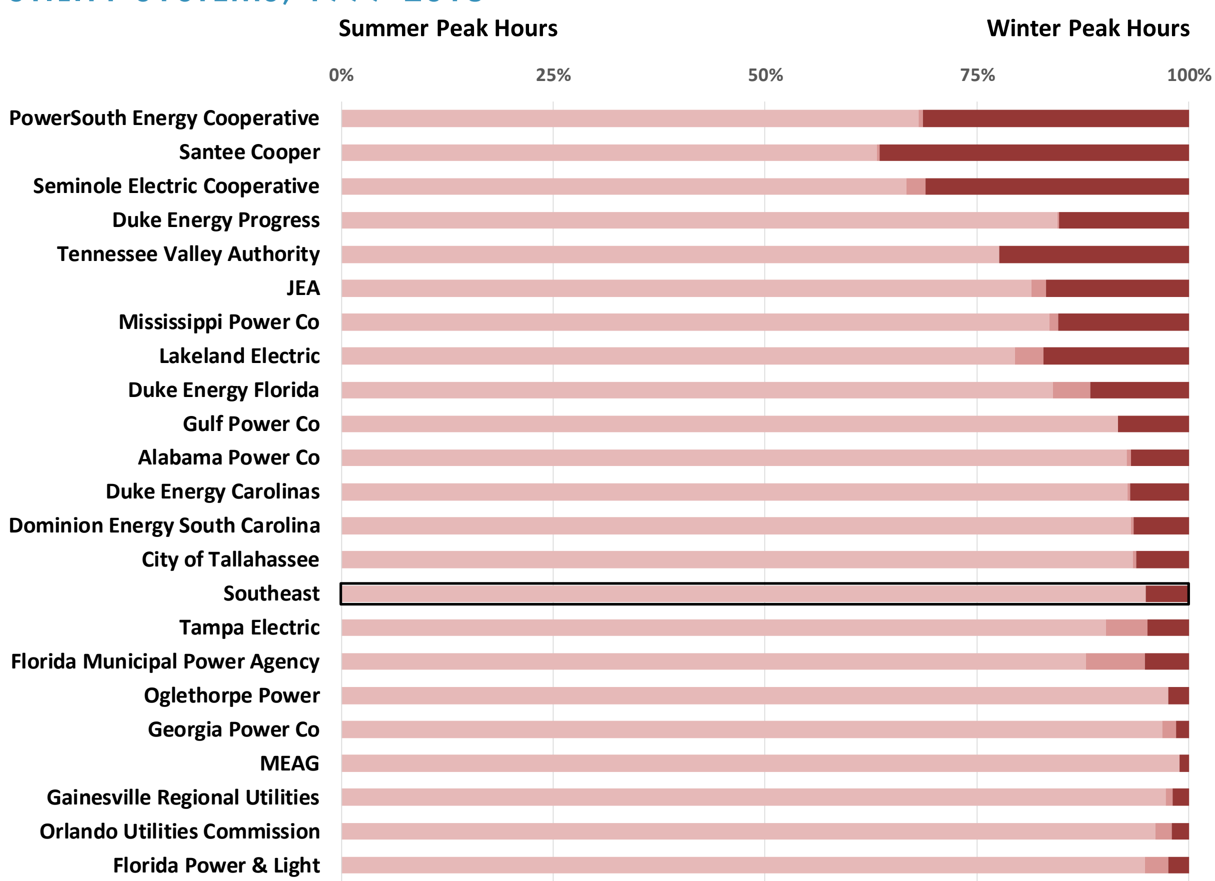


Source: SACE analysis of utility data filed on FERC Form 714 for 1999-2018. For some utilities, data coverage is incomplete.

UTILITY TENDENCIES FOR SEASONAL PEAKS: Regional trends towards converging winter and summer peaks, and the overall prevalence of summer peak hours, is generally reflected in individual utility data. However, there is substantial variation among utilities and trends in seasonal peaks are less clear-cut.

One measure that helps classify the seasonal peaking character of a utility system is to compare the number of peak hours by season. In Figure 6, the relative share of seasonal peak hours is graphed, considering the top 1.1% of total system load hours ranked by system load factor. (These are the same data reflected in Figure 3, above.) Southeastern systems range from a high of 36% of peak hours in the winter at Santee Cooper to a low of 1% at MEAG (Municipal Electric Authority of Georgia). Even for systems like Santee Cooper that often experience the highest peak during the winter season, high load hours occur *more frequently* in the summer.

FIGURE 6: PEAK HOURS, BY SEASON, REPORTED BY SOUTHEASTERN UTILITY SYSTEMS, 1999-2018



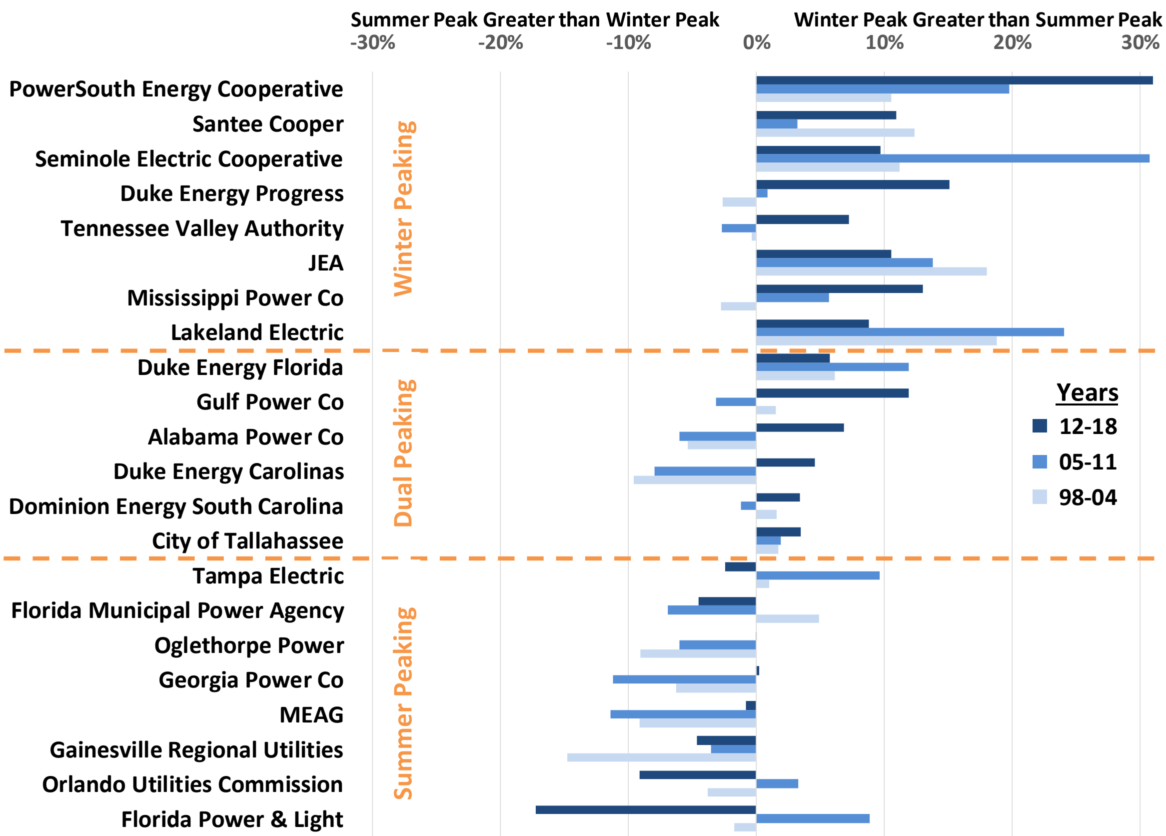
Source: SACE analysis of utility data filed on FERC Form 714 for 1999-2018. For some utilities, data coverage is incomplete.
Notes: Intermediate colored area represents shoulder months. Typically, November reflects winter characteristics, and May reflects summer characteristics. Southeast peak hours are regional coincident data, not an average of utility counts.

Another measure used to classify the seasonal peaking character of a utility system is the ratio of maximum winter and summer peaks. As illustrated in Figure 7, utilities with a relatively high number of winter peak hours tend to also have winter peaks greater than summer peaks. Figure 7 compares the maximum winter and summer peaks during three seven-year periods. For purposes of classifying utility systems by season, this report uses only the most recent seven-year period.

Trends at individual utility systems may or may not be meaningful. As discussed above, variability in winter peaks may simply reflect normal statistical variability. On the other hand, it is notable that with the convergence of winter and summer peaks across the region generally, Figure 7 illustrates that winter peaks over the past seven years have exceeded summer peaks at 16 of 22 utility systems. Prior to 2012, utility system peaks were divided more evenly between winter and summer maximum values.

Apparent trends towards winter peaking (e.g., DEP) or summer peaking (e.g., JEA) may simply be artifacts of the narrow gap between winter and summer peaks for most Southeast utilities. Climatic or technological drivers do not appear correlated with these apparent trends, as evidenced in Figure 7 by JEA and the City of Tallahassee (nearby municipal utilities) showing opposite trends.

FIGURE 7: SEASONAL PEAKS REPORTED BY SOUTHEASTERN UTILITY SYSTEMS, 1998-2018



Source: SACE analysis of utility data filed on FERC Form 714 for 1998-2018. For some utilities, data coverage is incomplete.

COMPARISON OF SEASONAL PEAK CHARACTERISTICS: There are two patterns that help explain how the number of summer peak hours is higher at all Southeastern utilities, even at utilities that often experience annual peaks during the winter season.

First, the highest winter peak events[12] tend to be less frequent compared to summer peaks. As summarized in Table 4, peak events at Southeastern utilities are most likely to occur during the summer. (Utilities are ranked in the same order as Figure 5.) Across the Southeast, only 1 in 11 peak events occurs in the winter.

However, this number varies widely by utility. Winter peak events at Santee Cooper, PowerSouth, and Seminole Electric represent 1/4 to 2/5 of all events. At the other extreme, utilities such as Georgia Power, Florida Power & Light, and Oglethorpe Power experience just one winter peak out of every 30 peak events.

Second, winter peak events tend to be shorter in duration than summer peaks at most Southeastern utilities. Also summarized in Table 4 are the average durations for each utility's summer, winter, and shoulder peaks. While four utilities have longer average peaks in the winter, most utilities have summer peaks that last one or two hours longer than winter peaks. The average Southeastern regional peak event is almost 2 hours longer in the summer than in the winter.

The shorter duration winter peaks affect the capability of utilities in the Southeast to rely on neighbors for generation. As shown in Table 4, the average Southeastern regional winter peak is just 2.6 hours, which is shorter than the average winter peak duration for most of the individual utility systems. This is because winter peaks in the Southeast are less coincident than summer peaks. Shorter system peaks mean that coincident regional demand peaks more briefly during winter peak events – utilities experience winter peaks during slightly different hours.

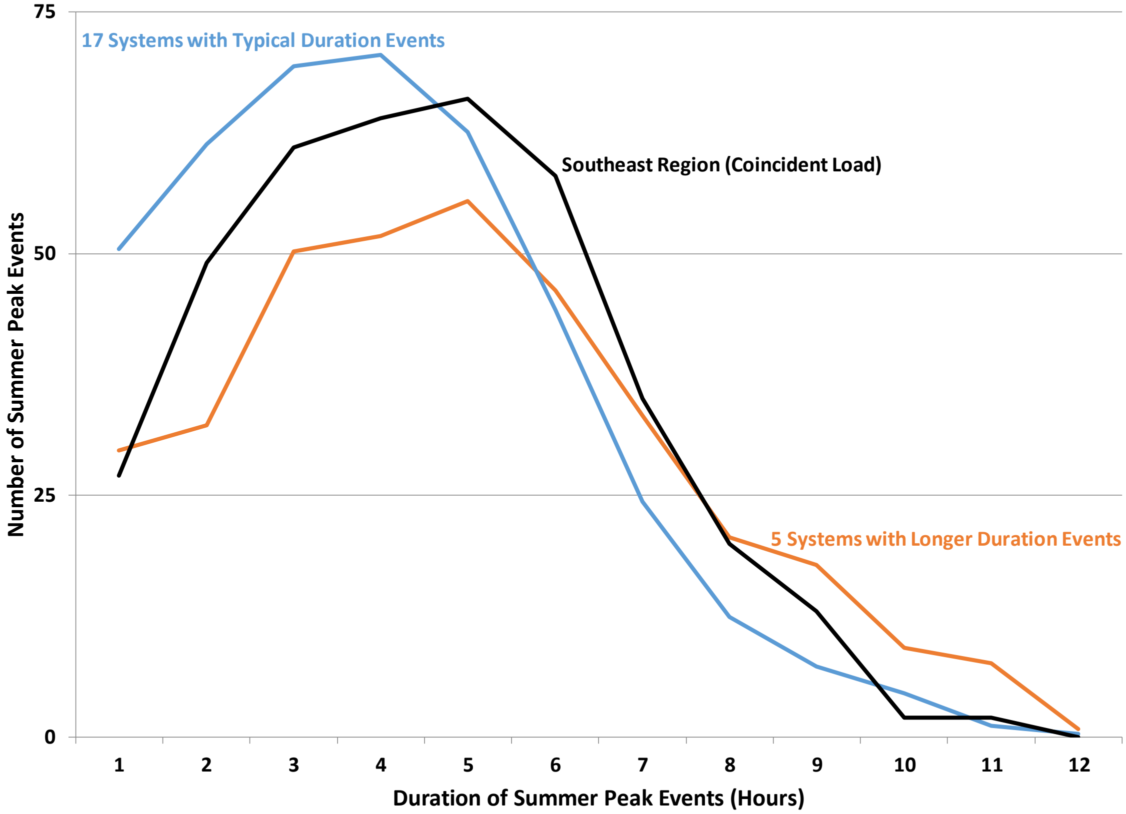
[12] A peak event is defined as a series of nearly-consecutive hours with a system load factor in the top 1.1% of the 20-year dataset. Summer peak events are all contained on a single calendar day. Winter peak events may stretch over more than one day, and there may be two winter peak events on the same day. By "nearly-consecutive," winter days are limited to no more than 2 non-peak hours during a single event. Summer events include all peak hours on the same calendar day. Our definition of peak events is not intended to relate to a utility's designation of a "peak event," such as for purposes of a peak pricing or demand response program.

TABLE 4: DISTRIBUTION AND DURATION OF PEAK LOAD EVENTS ON SOUTHEASTERN UTILITY SYSTEMS, 1999-2018

	UTILITY SYSTEM	PEAK EVENT DISTRIBUTION			AVERAGE DURATION (HOURS)			LONG DURATION WINTER EVENTS
		Summer	Winter	Shoulder	Summer	Winter	Shoulder	
	SOUTHEAST (COINCIDENT)	91 %	9 %	0 %	4.5	2.6	n/a	0
WINTER PEAKING	PowerSouth	63 %	36 %	1 %	4.6	3.8	2.0	10
WINTER PEAKING	Santee Cooper	61 %	38 %	1 %	4.5	4.2	2.0	13
WINTER PEAKING	Seminole	70 %	26 %	3 %	3.8	4.9	2.5	11
WINTER PEAKING	DEP	79 %	20 %	1 %	5.3	3.8	1.5	3
WINTER PEAKING	TVA	82 %	18 %	0 %	4.7	6.1	n/a	10
WINTER PEAKING	JEA	80 %	18 %	2 %	4.2	3.8	3.3	3
WINTER PEAKING	Mississippi Power	84 %	14 %	2 %	4.4	4.7	3.0	5
WINTER PEAKING	Lakeland	81 %	15 %	4 %	3.5	4.1	2.8	4
DUAL PEAKING	DEF	82 %	12 %	6 %	3.9	3.6	2.8	2
DUAL PEAKING	Gulf Power	92 %	8 %	0 %	4.3	4.6	n/a	2
DUAL PEAKING	Alabama Power	90 %	9 %	1 %	5.0	3.6	2.5	1
DUAL PEAKING	DEC	90 %	10 %	0 %	4.9	3.5	3.0	1
DUAL PEAKING	DESC	90 %	9 %	1 %	5.0	3.3	2.5	1
DUAL PEAKING	Tallahassee	92 %	7 %	1 %	3.5	3.1	2.7	1
SUMMER PEAKING	Tampa Electric	89 %	5 %	6 %	3.7	3.3	3.0	0
SUMMER PEAKING	FMPA	86 %	7 %	7 %	3.8	2.9	3.5	0
SUMMER PEAKING	Oglethorpe	96 %	4 %	0 %	4.4	2.9	n/a	0
SUMMER PEAKING	Georgia Power	95 %	3 %	2 %	4.6	2.3	4.0	0
SUMMER PEAKING	MEAG	98 %	2 %	0 %	4.4	2.6	n/a	0
SUMMER PEAKING	Gainesville	95 %	3 %	2 %	3.7	2.4	1.7	0
SUMMER PEAKING	Orlando	93 %	3 %	4 %	3.7	2.3	1.7	0
SUMMER PEAKING	FPL	94 %	3 %	3 %	4.0	3.4	3.2	0

Source: SACE analysis of utility data filed on FERC Form 714 for 1999-2018. For some utilities, data coverage is incomplete.

FIGURE 8: SUMMER PEAK EVENT DURATION OF SOUTHEASTERN UTILITY SYSTEMS, 1999-2018



Source: SACE analysis of utility data filed on FERC Form 714 for 1999-2018. For some utilities, data coverage is incomplete.

Third, however, winter and dual peaking utilities can have long duration winter peak events. Long duration winter peak events are defined as any event with more than 12 consecutive (or nearly consecutive) hours of load meeting our definition of peak hours. As summarized in Table 4, four utilities experienced the vast majority of long duration winter peak events in the Southeast, and these events do not occur at summer peaking utilities, nor do these events occur on a regional basis.[13] Long winter peaks tend to happen during prolonged cold waves and can infrequently extend for more than 20 hours.

Of note are the multi-hour shoulder season peaks, which occur mainly in Florida during middays in May or October, and are essentially extensions of summer peaks. (May and October are not typically classified as summer months by utility convention.) There have been a few April or November peak events at a few utilities that resemble winter peaks as well.

[13] The longest Southeast regional winter peak events lasted 6 hours.

SUMMER PEAK EVENT DURATIONS ARE SIMILAR AT MOST UTILITIES: As illustrated in Figure 8, summer peak events in the Southeast are usually less than 5 hours long. On average, most Southeast utility systems experience 8+ hour summer peaks only once a year. However, five utility systems experience summer peaks of 8-12 hours roughly three times a year. None of the summer peaks are longer than 12 hours since it generally cools overnight and also businesses generally reduce their electricity use when they are not open. The five longer-peaking systems are Alabama Power, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, and Georgia Power. As shown in Table 4, four of these longer-peaking systems also stand out as having average peak duration of about 5 hours, compared to other Southeastern utilities with average peak duration of 3.5 - 4.5 hours.

Load shapes on days with summer peak events tend to be very consistent load shapes. Figure 10 below illustrates the load shape for the top 10 summer peak events on the Oglethorpe Power system. Similar to most Southeastern utilities, Oglethorpe's summer peak load shape is very consistent across peak events. The duration of the peak event is mainly a reflection of the magnitude of the peak.

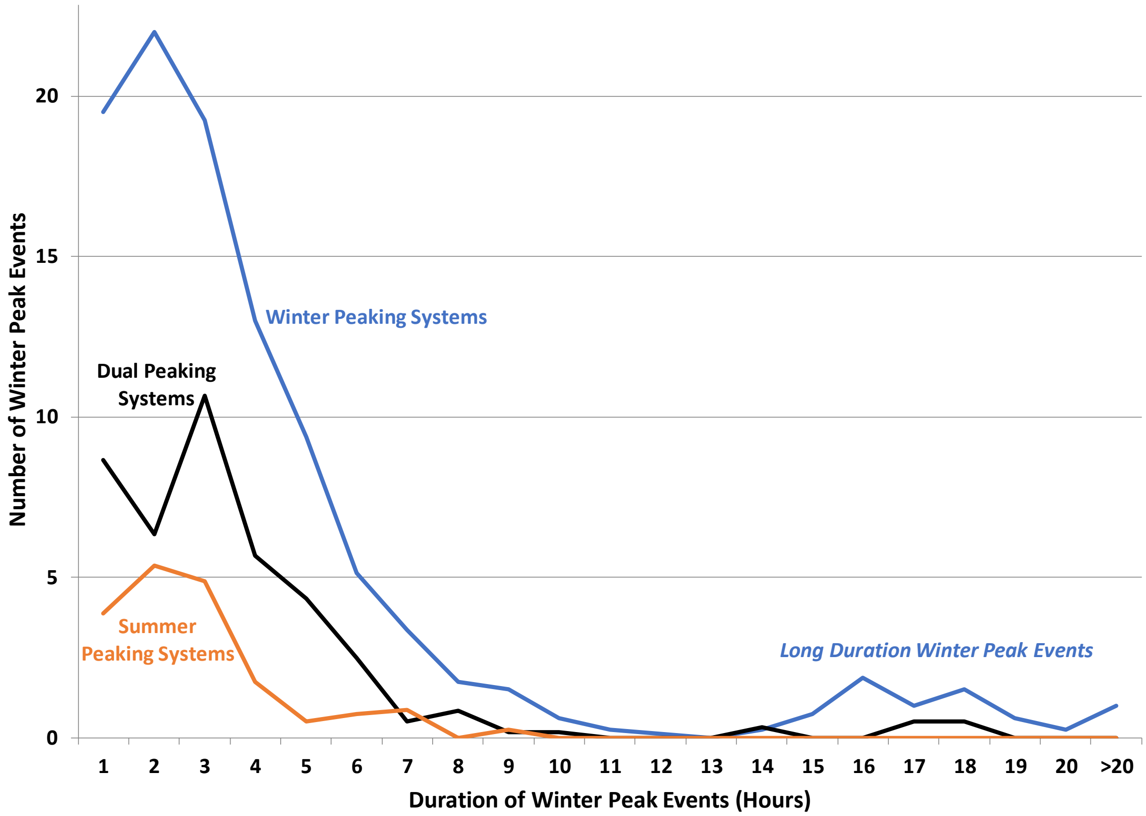
WINTER PEAK EVENT DURATIONS VARY AMONG SOUTHEASTERN UTILITIES: The duration of winter peak events varies significantly depending on the seasonal character of the utility system, as illustrated in Figure 9.

- Summer peaking systems – The typical summer peaking system has about 1 winter peak event per year, with half having a duration of 2 hours or fewer, and never exceeding 9 hours in duration.
- Dual peaking systems – The typical dual peaking utility system has about 2 winter peak events per year, with nearly two-thirds having a duration of 3 hours or fewer. Very rarely, these systems will experience a long duration peak event of 13-18 hours.
- Winter peaking systems – The typical winter peaking utility system has about 5 winter peak events per year, with over half having a duration of 3 hours or fewer. At four of these systems, a long duration peak event of more than 12 hours occurs every other year on average. At TVA, these events have only emerged in the past decade and are particularly long in duration, as shown in Figure 11.

It should be emphasized that a long duration winter peak events does not mean continuous demand at the system's seasonal peak. Demand will vary during these periods, but all of these hours have load factors in the top 1.1% experienced by that utility system.

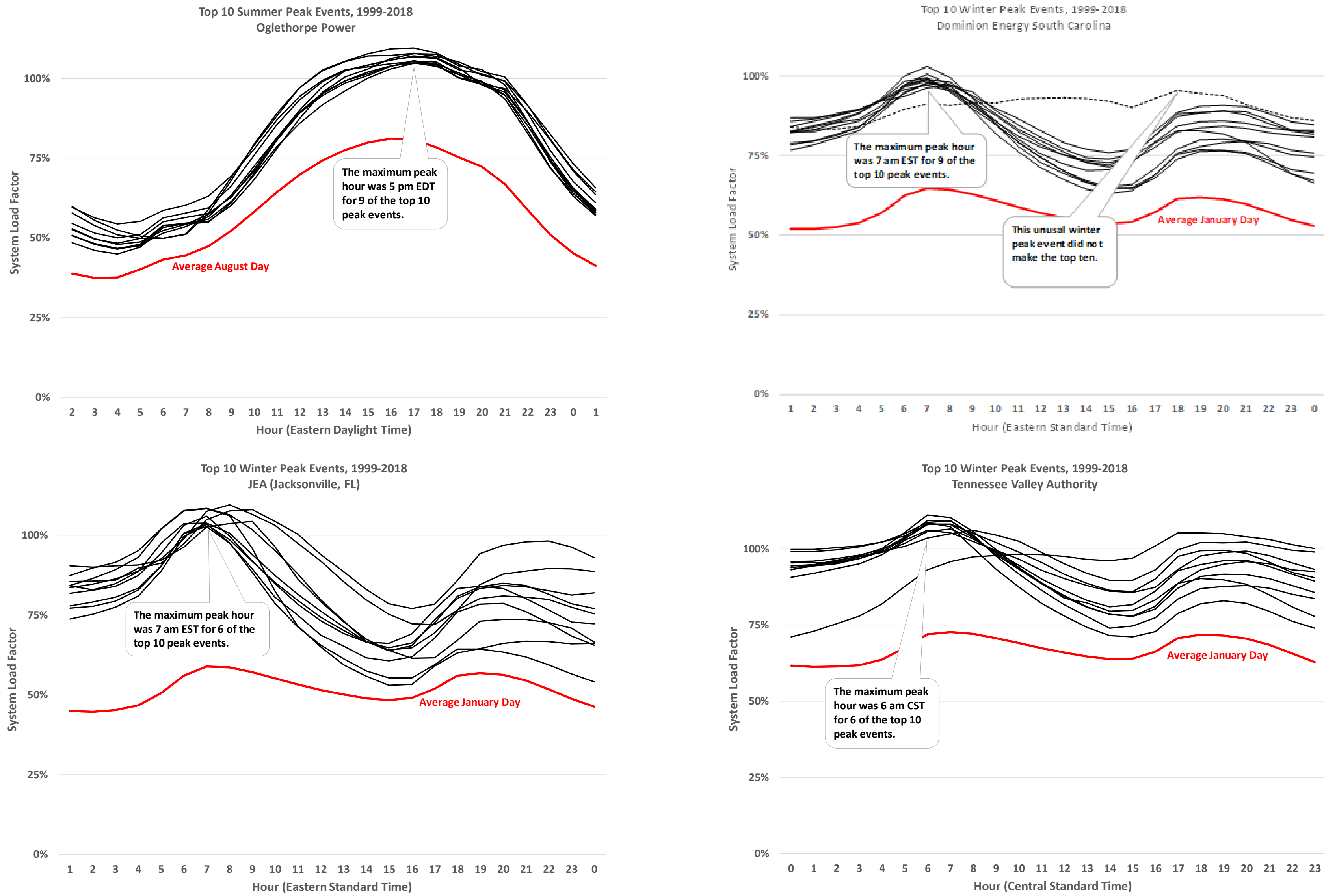
Load shapes on days with winter peak events tend to be less consistent than those for days with summer peak events. In Figure 10, the load shape for the top 10 winter peak events are illustrated for Dominion Energy South Carolina, JEA and the Tennessee Valley Authority systems. Like most dual peaking systems, DESC's winter peak load shape is consistent across most peak events (although one anomalous event is illustrated), but winter peaking systems like JEA and TVA illustrate more diversity, particularly as illustrated for TVA in Figure 11.

FIGURE 9: WINTER PEAK EVENT DURATION OF SOUTHEASTERN UTILITY SYSTEMS, 1999-2018



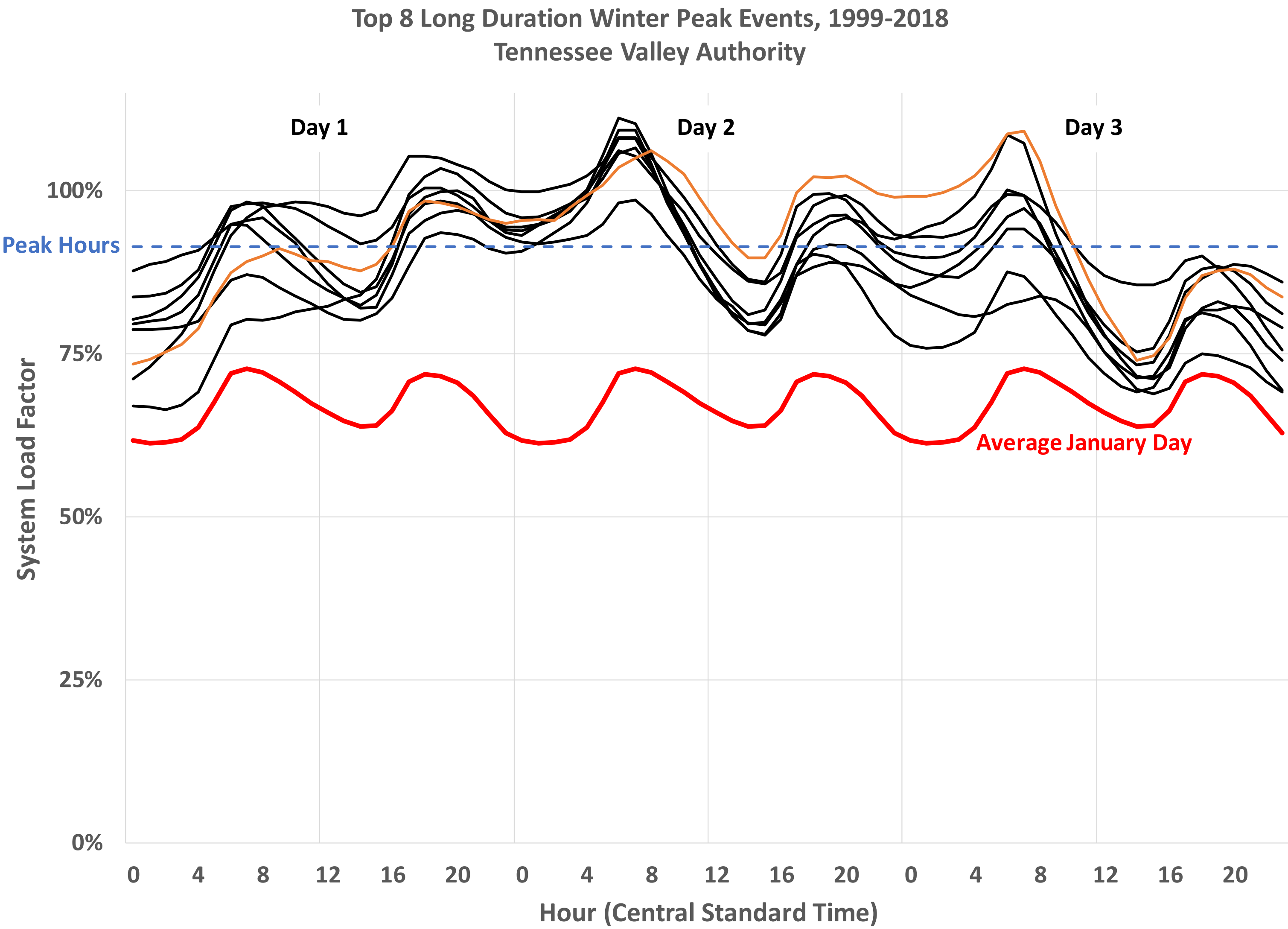
Source: SACE analysis of utility data filed on FERC Form 714 for 1999-2018. For some utilities, data coverage is incomplete.

FIGURE 10: SEASONAL PEAK LOAD SHAPES FOR REPRESENTATIVE UTILITY SYSTEMS



Source: SACE analysis of utility data filed on FERC Form 714 for 1999-2018.

FIGURE 11: LONG DURATION WINTER EVENTS, TENNESSEE VALLEY AUTHORITY



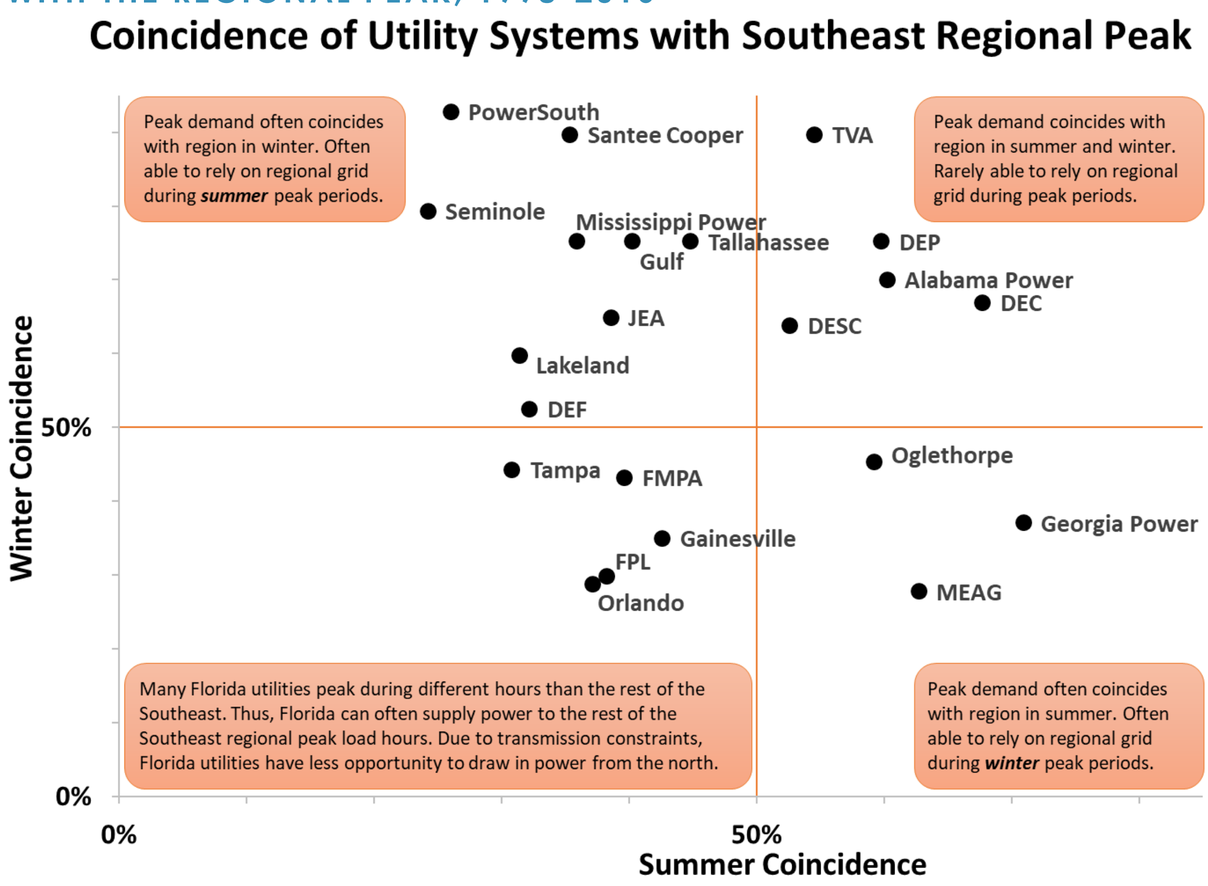
Source: SACE analysis of utility data filed on FERC Form 714 for 1999-2018. Orange line highlights a particularly long event.

COINCIDENCE OF UTILITY SYSTEM PEAK WITH SOUTHEASTERN SYSTEM PEAK: Utility systems often peak on the same day as utilities that are neighbors, with similar climates and customer profiles. The Southeast region's overall peak demand is most closely associated with the peak demands of four of the larger utilities, including Alabama Power, DEC, DEP, and TVA, and one smaller utility, DESC.

The significance of a coincident peak between the utility and the region is that the utility is less able obtain excess power from outside its system if every utility is peaking. When there is not a coincident peak, the utility in need of power has more options for obtaining that power via the regional grid. For example, Alabama Power peaked on about 61% of the Southeast region's peak hours, so Alabama Power would have more access to regional reserve power resources during the 39% of its peak hours when the region was not at peak demand.

The relationship of individual utility systems to the regional peak can be characterized in four groups, as illustrated in Figure 12.

FIGURE 12: HOURLY COINCIDENCE RATE OF SOUTHEASTERN UTILITIES WITH THE REGIONAL PEAK, 1998-2016



Source: SACE analysis of utility data filed on FERC Form 714 for 1998-2016. For some utilities, data coverage is incomplete.

- Four large utilities (Alabama Power, DEC, DEP and TVA) and one smaller utility (DESC) have peaks that usually coincide with the regional peak regardless of season.
- Three utilities in Georgia have peaks that coincide with the regional peak during the summer, but are often not peaking during regional winter peak hours.
- Four rural and four Florida utilities have peaks that usually coincide with the regional peak during the winter, but are often not peaking during regional summer peak hours.
- Five Florida utilities most often peak during different hours than the rest of the Southeast. Utilities in peninsular Florida (all except Gulf Power and PowerSouth) are constrained in the amount of additional power that may be imported during peak events by limited uncommitted transmission with the rest of the region. However, when the rest of the region is peaking, Florida utilities can often supply excess power to those utilities, especially during summer peak events.

While the Southeast does not have a substantial, organized market for power, bilateral transactions between utility systems are common and do have an influence on power plant development by utilities and independent developers.

COMMENTARY

The characteristics of Southeastern utilities' peak loads are important for a number of reasons. Even though the Southeast lacks a substantial, organized market, utility planning for resource acquisition and independent power development are important activities that determine the cost and reliability of power in the Southeast. Forecasts for peak demand play a key role in this utility planning process. Some observations related to these issues are offered below.

It is surprising just how steady seasonal peak demand characteristics have been over the past 20 years studied here. Certainly, there have been notable shifts from growth to flat or declining annual energy consumption. The recent decline in regional summer peak demand has resulted in a convergence of seasonal peaks. But in many other respects, things are relatively unchanged. Seasonal variability shows no significant trend. Summer and winter peak durations appear similar now to two decades ago.

The seasonal character of utility demand has some association with geography, but geography is not the only important factor. The three Georgia utilities have similar coincidence with Southeast regional peaks (see Figure 12), but utilities in Florida have very different winter coincidence characteristics. Notably, the only summer peaking utilities in the Southeast are in Florida and Georgia.

Yet winter peak demand doesn't seem to be geographic. The most strongly winter peaking systems, such as Mississippi Power, Seminole, PowerSouth and Santee Cooper have higher rural service territories. While data do not allow deep analysis of this tendency, rural systems may have a tendency towards winter demand peaks.

Another characteristic we considered was the relative shares of residential, commercial and industrial load. Utility systems with high commercial loads are associated with summer peaking, and those with low commercial loads are associated with winter peaking. The association of any particular customer class with winter peaks is less clear. Residential demand has a relatively weak association with winter peaking systems, and industrial demand has a similar weak association with summer peaking systems. But the statistical reliability of these findings does not appear to be strong, perhaps because customer class data are only available for retail sales (not peak demand), or because winter peaking systems are not strongly associated with any particular customer class.

Florida's peak demand patterns tend to be different from the rest of the Southeast. Peninsular Florida utilities control roughly 1/4th of the region's power supply, including significant resources to the north such as a portion of Plant Scherer in Georgia. Yet bilateral market transactions between these utilities and their neighbors to the north are constrained by limited transmission capacity.

- Because some of the power resources controlled by Florida utilities are located to the north (mainly in Georgia), it is feasible to re-direct Florida-controlled generation to supply other utilities such as those in Georgia or the Carolinas.
- Summer peak events are often characterized by high peak demand in Alabama, Tennessee, Georgia and the Carolinas, but milder demand in peninsular Florida. During such conditions, Florida utilities are in a strong position to market their surplus power resources to assist with meeting regional demand. [14]
- However, when Florida is peaking, those same transmission systems will likely be congested due to the commitment of transmission to deliver power from plants that are located north of Florida to their owners in peninsular Florida. As a result, Florida utilities probably have less frequent opportunities to obtain short-term supplies from outside the peninsula region during peak events.

Thus, Florida power plant owners with excess reserve capacity will tend to be in a strong position to sell power either to a constrained Florida market or to a large Southeastern market during peak events.

[14] Such transactions are disincentivized by the "pancaking" of multiple transmission charges when attempting to sell power to a utility that is not immediately adjacent.

Even though the Southeast is dual peaking, the summer season likely remains the most constrained in terms of generation resources. Several factors outside the scope of this analysis must also be considered when evaluating resource constraints.

- Thermal power plants (especially coal and nuclear) tend to provide less power during hot summer peak events. This is primarily due to more inefficient operation of cooling systems.
- Transmission systems are at greater risk of failure in hot weather. A major cause of transmission system failure is excessive temperatures in power equipment or along power lines caused by both air temperatures and heat buildup due to high power demand over longer periods of time.

The reliability risks to power and transmission resources are associated not only with demand during the largest peak event, but with the number of hours that a system is at or near peak demand. Considering that there are about 20 times as many summer peak hours than winter peak hours, the cumulative reliability risk associated with thermal power plant failures and transmission asset failures are higher in the summer season as a whole for all (or nearly all) utilities in the Southeast.

Another reliability risk related to power resources is the scheduling of maintenance or plant upgrades. If too many generators are undergoing seasonal maintenance and there are power supply disruptions, reliability issues can occur even during periods of relatively modest power demand.

Some utility planners have suggested that reliability risk is increasing in the winter due to increasing variability in winter peaks and increased reliance on solar power. "Polar vortex" events have provided a visible example of the relevance of winter peak events to utility planning. For a few utilities, long duration winter peaks should be a significant planning consideration. Nevertheless, utility load data do not demonstrate a clear trend towards increases in winter peak hours, either at the regional level or at the individual utility level. Although solar power's generation profile is poorly aligned with winter peaks, other resources may be more reliably available for reasons described above. For these reasons, reliability risk in the winter may not be increasing as much as has been implied.

The fact that Southeast regional trends are not shared among all utility systems is a significant finding in and of itself. Seasonal peaks are variable across utility systems in the Southeast and do not appear to follow trends related solely to climate, technology, or other demographics. Utility planners and regulators should consider the context provided by regional data, apply a high degree of scrutiny to trends that may initially appear significant, and avoid being misled by statistically insignificant trends.

WHAT NEXT?

Throughout the process of developing this analysis and discussing with reviewers several additional questions arose that are worth future exploration but fall outside the scope of this work.

- How to take a deeper dive into the thesis that rural systems tend to be more winter-peaking, and what could be driving this trend?
- How does building stock play a role in whether a utility system is summer, winter, or dual peaking?
- What do the frequency, shape, and duration of peak events, particularly the long-duration events, tell us about how to deploy solar, storage, and particularly the two combined? Similarly, what do these tell us about how to design and deploy energy efficiency and demand response that targets specific types of peak events?
- How do different rate structures either augment or mitigate winter peaks?
- How predictable are the peaks, particularly the long-term winter peaks, and how long do utilities have to prepare for them?
- How can this analysis be applied to the distribution system to determine where utility systems are peaking, and help with both distribution planning and distributed energy resource deployment decisions? Can similar analysis be done at the feeder level?

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