Analysis of Solar Capacity Equivalent Values
for the South Carolina Electric and Gas System

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The assessment of solar energy's contribution to meeting peak demands by South Carolina Electric and Gas Company (SCE&G) undervalues the actual capacity benefit of solar. This is particularly true in the summer and for tracking systems. SCE&G undervalues solar because the company assesses solar contribution to peak using what appears to be simplistic averages of solar capacity factors during certain hours, regardless of whether the system is peaking during those hours.[1] This method is flawed because it gives the same weight to on-peak solar generation (e.g., during the hottest, sunniest hour of a peak load afternoon) as to off-peak generation (e.g., during a summer thunderstorm).

Solar contributes far more to summer peak resource needs than SCE&G currently acknowledges. The contribution of solar power to peak resource needs is measured by the capacity equivalent value, the amount of on-peak power that solar power is expected to provide during peak demand periods. SCE&G's assessment of capacity equivalent values for solar in its Integrated Resource Plan (IRP) differs from this report in three critical ways.

- Fixed mount systems provide 66% on-peak power, about one-third greater summer capacity equivalent values than the value assumed in the IRP.
- Single axis tracking systems provide 74% on-peak power, nearly half again as much capacity equivalent than the value assumed in the IRP.
- Although winter capacity equivalent values are low, winter peaks are infrequent: Of 1,579 peak hours in this analysis, only 77 occurred during winter months.

Table 1, below, compares the values used in SCE&G's resource plan with the capacity equivalent value, calculated as discussed later in this report.

Table 1: Comparison of solar capacity equivalent values used for SCE&G IRP vs. values based on SACE analysis of Clean Power Research data

	Capacity Equivalent Value
Summer Capacity Equivalent	
IRP – PV solar[A]	**50.0 %**
Fixed mount PV system[B]	66.1 %
Single axis tracking PV system[B]	74.2 %
Winter Capacity Equivalent	
IRP – PV solar[A]	**(not specified)**
Fixed mount PV system[B]	3.1 %
Single axis tracking PV system[B]	6.5 %

Source A: SCE&G 2017 IRP, p. 37.
Source B: SACE analysis of Clean Power Research data.

[1] Capacity factor refers to the percent of maximum output for a generation resource. For example, a 50% capacity factor means that a generation resource is expected to generate 50% of the maximum possible output.

SACE's analysis of Clean Power Research's solar generation simulations showed that instead of 50%, the summer capacity equivalent value of solar power should be 66 - 74%, depending on solar technology.

These calculations are derived directly from two hourly datasets covering the 1998-2015 time period.[2] One dataset includes the actual hourly system load and year-ahead peak load forecast for the SCE&G planning area; these data are filed by SCE&G on FERC Form 714. The second dataset are simulated hourly generation profiles, relying on actual observed weather conditions, for fixed mount and a single axis tracking PV systems at 14 locations in or adjacent to South Carolina. These data were provided to SACE by Clean Power Research using its SolarAnywhere model (see attached documentation).[3]

By aligning historical system load data with simulated solar generation, the actual performance of solar PV systems can be evaluated under a range of recent meteorological conditions. The 1998-2015 coverage allows for nearly 135,000 comparisons of hourly system load with hourly solar generation. As such, it provides an opportunity to conduct a robust statistical analysis of the correlation of solar generation to system load during peak periods.

A. SCE&G's methods for calculating solar capacity equivalence value

Capacity equivalent values based on analysis of Clean Power Research data are significantly higher than those based on SCE&G's analysis and methods. SCE&G's methods give equal weight to solar generation during an on-peak hour (e.g., during the hottest, sunniest hour of a peak load afternoon) as during an off-peak hour (e.g., during a summer rainshower). This is true for each of the two different methods used by SCE&G to place a capacity value on solar power.

One method used by SCE&G to determine the capacity equivalent value for solar power is used in its integrated resource plans. Based on the description of these values, it appears that SCE&G calculates these values for the summer only, by averaging solar generation during certain hours.

- In 2013, SCE&G used a 61% capacity equivalent value.[4]

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[2] SCE&G data for calendar year 2004 are not available from the FERC website. Throughout this report, data reported for 1998-2015 does not include data from 2004.

[3] Using its SolarAnywhere model, Clean Power Research conducted hourly simulations for seven different configurations of solar photovoltaic (PV) systems at 147 locations across the Southeast region, including South Carolina. This analysis is based on the simulated hourly production data produced by Clean Power Research, as explained in the attached documentation.

[4] "… 700 megawatts of solar capacity in 2015 with 427 megawatts coincidental with the system peak …" SCE&G 2013 IRP, p. 33.

- In 2014, SCE&G used a 48% capacity equivalent value.[5]
- In 2015, SCE&G did not specify its capacity equivalent value in its IRP.
- In 2016 and 2017, SCE&G used a 50% capacity equivalent value.[6]

SCE&G has not specified the hours used for averaging the capacity factors, nor explained the substantial year-to-year changes. Furthermore, SCE&G appears to lack any capacity equivalent value for winter season planning purposes.

The second method used by SCE&G to place capacity value on solar power does not include the calculation of a system-wide capacity equivalent value, but rather embeds this calculation within its Public Utility Regulatory Policy Act (PURPA) calculations of avoided capacity costs, as reflected in related tariffs.[7] According to testimony filed by SCE&G, its PURPA avoided cost PR-1 and PR-2 tariffs assign capacity value based on the actual performance of solar systems during "critical peak hours."[8]

B. Flaws in SCE&G's solar capacity equivalence methods

SCE&G's two methods for evaluating solar capacity equivalence do not reflect the actual performance of solar on its system. Each method *inappropriately excludes* many hours in which system peak loads are observed and *inappropriately includes* many hours in which system peak loads are *not* observed.

SCE&G's method for evaluating solar capacity equivalence for its IRP appears to be an average of solar generation during some hours during the summer months (see footnote 5). However, because SCE&G has not explained its calculation of solar capacity equivalent values in recent IRPs, the ability to provide a detailed critique of those calculations is limited.

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[5] "Approximately 56% of the DC rating of solar capacity will be generating on a summer afternoon and contribute to reducing the summer peak demand. There will be no solar generation at the time of SCE&G's winter peak demand which usually occurs between 7 and 8 am." SCE&G 2014 IRP, p. 39.

[6] SCE&G 2016 IRP p. 38; SCE&G 2017 IRP, p. 37.

[7] In 2014, in response to SACE testimony describing a proposed method for calculating the capacity equivalent value, SCE&G witness Joseph Lynch testified that, "Determining the firm capacity level of a [Distributed Energy Resource (DER)] is a utility specific calculation which will be a function of its system load profile, various weather conditions such as solar radiation, cloud cover, wind speed -- all depending in part on the geographic location of the service territory. The determination of firm capacity level for a DER is more properly addressed in the docket where each utility files [its utility-specific rates]." South Carolina Electric & Gas, *Rebuttal Testimony of Joseph M. Lynch on behalf of South Carolina Electric & Gas Company,* South Carolina Public Service Commission Docket No. 2014-246-E (January 13, 2015), p. 6.

[8] SCE&G identified the set of critical peak hours where energy would have a capacity value on the system and spread the avoided capacity cost across those hours. A capacity credit is then paid for whatever QF energy is provided during the critical peak period. *Direct Testimony of Joseph M. Lynch on Behalf of South Carolina Electric & Gas Company*, South Carolina Public Service Commission Docket No. 2016-2-E (March 4, 2016), p. 16.

Nonetheless, the analysis of Clean Power Research's data provided in this report demonstrates that the IRPs undervalue the actual capacity benefit of solar power, as shown in Table 1.

(1) SCE&G's critical peak period inappropriately excludes many system peak load hours

The SCE&G system is not limited to peak hours during the critical peak hour periods defined in the PR-1 and PR-2 tariffs.[9] SCE&G defines its critical peak hours as between 6 am and 9 am, Monday through Friday, in the winter, and between 2 pm and 6 pm, Monday through Friday, in the summer.[10] With regard to reliability, however, what matters is not a standard period of time in which the system often peaks, but rather the hours in which the actual peak is relatively high compared to the forecast peak.

The importance of focusing on hours in which the actual peak is relatively high compared to forecast peak is related to the reason that utilities value capacity. Capacity is needed in order to serve peak demand, and the risk of not being able to serve peak demand is measured in a reliability assessment. A reliability assessment considers many factors in measuring that risk, the most important of which is the actual demand in a given hour. In contrast, SCE&G's critical peak hours method includes some hours with peak demand, but also many other hours in which demand is well below peak, hours in which the reliability risk is nearly zero. A better approach to measuring the contribution of solar power to system reliability is to conduct a robust statistical analysis of the correlation of solar generation to system load during peak periods.

Accurately identifying the peak periods is a critical element of this method. Hours with actual reliability risk occur more frequently in years with atypical weather – unusually hot summers or cold winters. Not all years are equal in a reliability assessment. For example, in 2009 the SCE&G peak was only 4,718 MW, whereas in 2007 it was 4,926 MW. Thus the performance of solar during peak hours in 2007 would have benefitted system reliability more than it would have during the less extreme 2009 peak hours when SCE&G likely had capacity to spare.

In order to evaluate solar generation during the hours that "matter" for purposes of system reliability, this analysis considers solar performance during the top 1% of hours (1998-2015) based on system load factor.[11] Table 2, below, demonstrates that summer peak hours may occur any time between 10 am and 10 pm EDT. Winter peaks are relatively rare, comprising

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[9] For the most recently proposed PR-1 and PR-2 tariffs, see *Direct Testimony of Allen W. Rooks on Behalf of South Carolina Electric & Gas Company*, South Carolina Public Service Commission Docket No. 2017-2-E (February 24, 2017), exhibits AWR-13, AWR-15.

[10] *Direct Testimony of Joseph M. Lynch on Behalf of South Carolina Electric & Gas Company*, South Carolina Public Service Commission Docket No. 2016-2-E (March 4, 2016), p. 17.

[11] Load factor is calculated as hourly load divided by the annual peak, as forecast in the prior year by SCE&G. For SCE&G, the top 1% load factor hours are hours with a load factor of 91% or greater.

only about 5% of the high load factor hours analyzed for this study. About 66% of high load factor hours occur during the SCE&G critical peak hours.[12] Thus, many peak hours during which reliability risks are higher are likely to occur outside the critical peak hours in the SCE&G tariffs.

Table 2: SCE&G peak hour distribution, 1998-2015

Hour Beginning		Summer						Winter					
EST	**EDT**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**
23	**0**	0	0	0	0	0	0	0	0	0	0	0	0
0	**1**	0	0	0	0	0	0	0	0	0	0	0	0
1	**2**	0	0	0	0	0	0	0	0	0	0	0	0
2	**3**	0	0	0	0	0	0	0	0	0	0	0	0
3	**4**	0	0	0	0	0	0	0	0	0	0	0	0
4	**5**	0	0	0	0	0	0	0	0	0	0	0	0
5	**6**	0	0	0	0	0	0	0	2	1	0	0	0
6	**7**	0	0	0	0	0	0	3	10	1	2	0	0
7	**8**	0	0	0	0	0	0	4	18	5	3	0	0
8	**9**	0	0	0	0	0	0	3	12	1	2	0	0
9	**10**	0	0	0	0	0	0	2	2	0	0	0	0
10	**11**	6	12	7	0	0	0	0	1	0	0	0	0
11	**12**	17	40	36	0	0	0	0	0	0	0	0	0
12	**13**	29	67	61	2	0	0	0	0	0	0	0	0
13	**14**	41	95	89	2	0	0	0	0	0	0	0	2
14	**15**	47	107	98	4	0	0	0	0	0	0	0	2
15	**16**	48	103	98	8	0	0	0	0	0	0	0	4
16	**17**	41	85	82	2	0	0	0	0	0	0	0	2
17	**18**	26	57	54	0	0	0	0	0	0	0	0	0
18	**19**	14	30	25	0	0	0	0	1	0	0	0	0
19	**20**	8	21	13	0	0	0	0	1	0	0	0	0
20	**21**	5	7	5	0	0	0	0	1	0	0	0	0
21	**22**	0	0	0	0	0	0	0	1	0	0	0	0
22	**23**	0	0	0	0	0	0	0	1	0	0	0	0
Monthly Total		**282**	**624**	**568**	**18**	**0**	**0**	**12**	**50**	**8**	**7**	**0**	**10**

Source: SCE&G data filed on FERC Form 714 for 1998-2015. The SCE&G critical peak hours are indicated by the boxes.

(2) Impact of solar deployment on SCE&G's peak hours

According to the 2017 SCE&G IRP, 280 MW of solar power have been deployed on the system.[13] Deployment of solar power affects the hours in which other resources are needed to address the system peak. Table 3 illustrates the impact of 280 MW on the hours in which the SCE&G system would peak, treating the 280 MW of solar power as a load reduction.[14] The impact of this level of solar deployment on solar peak hours is minimal; for example, net peak hours occur in winter months 6% of the time, an increase of only 5% from the baseline case.

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[12] Day of week restrictions were not considered in this analysis.

[13] SCE&G 2017 IRP, p. 37.

[14] To adjust for the reduction in net demand but maintain the 1% load factor threshold, the cutoff for the load factor was reduced from 91% to 90% for the 280 MW analysis. Even with the lower cutoff level, the he number of hours included in the analysis was reduced from 1,579 to 1,563.

Thus, the addition of additional solar resources does not change the finding that SCE&G's critical peak period inappropriately excludes many system peak load hours.

Table 3: SCE&G peak hour distribution, net of 280 MW of solar systems, 1998-2015

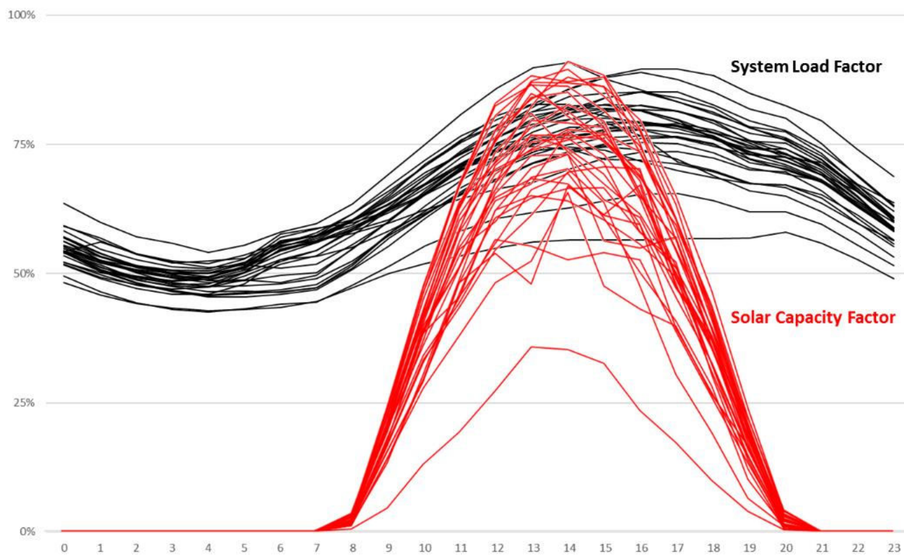
Hour Beginning		Summer						Winter					
EST	**EDT**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**
23	**0**	0	0	0	0	0	0	0	1	0	0	0	0
0	**1**	0	0	0	0	0	0	0	0	0	0	0	0
1	**2**	0	0	0	0	0	0	0	0	0	0	0	0
2	**3**	0	0	0	0	0	0	0	0	0	0	0	0
3	**4**	0	0	0	0	0	0	0	0	0	0	0	0
4	**5**	0	0	0	0	0	0	0	1	0	0	0	0
5	**6**	0	0	0	0	0	0	1	2	1	0	0	0
6	**7**	0	0	0	0	0	0	3	13	2	2	0	0
7	**8**	0	0	0	0	0	0	5	23	6	3	0	0
8	**9**	0	0	0	0	0	0	3	14	1	2	0	0
9	**10**	0	0	0	0	0	0	2	3	0	0	0	0
10	**11**	5	10	7	0	0	0	0	1	0	0	0	0
11	**12**	17	39	35	0	0	0	0	0	0	0	0	0
12	**13**	26	63	55	0	0	0	0	0	0	0	0	0
13	**14**	40	86	79	2	0	0	0	0	0	0	0	2
14	**15**	45	101	92	3	0	0	0	0	0	0	0	2
15	**16**	46	100	96	4	0	0	0	0	0	0	0	2
16	**17**	40	85	83	2	0	0	0	0	0	0	0	1
17	**18**	27	59	56	0	0	0	0	0	0	0	0	0
18	**19**	14	35	27	0	0	0	0	1	0	0	0	0
19	**20**	9	26	23	0	0	0	0	1	0	0	0	0
20	**21**	6	13	6	0	0	0	0	1	0	0	0	0
21	**22**	0	0	0	0	0	0	0	1	0	0	0	0
22	**23**	0	0	0	0	0	0	0	1	0	0	0	0
Monthly Total		**275**	**617**	**559**	**11**	**0**	**0**	**14**	**63**	**10**	**7**	**0**	**7**

Source: SCE&G data filed on FERC Form 714 for 1998-2015. The SCE&G critical peak hours are indicated by the boxes. Peak hours are selected based on a 1% system net load factor threshold. The net load factor for each hour is actual demand less solar generation divided by peak forecast demand less solar capacity. The 280 MW of solar generation and capacity are assumed to be south-facing fixed mount systems located at the six sites most closely associated with the SCE&G service area (see Table 6 and the attachment).

(3) SCE&G's critical peak period inappropriately includes many off-peak load hours

SCE&G's use of a critical peak period undervalues solar because it fails to track evidence that system load and solar generation are correlated, particularly in summer months. Figure 1, below, shows solar generation for an average fixed mount system for all hours of August 2015 in comparison to the SCE&G system load. On certain days, solar generation falls short of an optimal generation shape. For example, on August 7th at 1 pm EDT, solar generation is estimated at a 48% capacity factor.

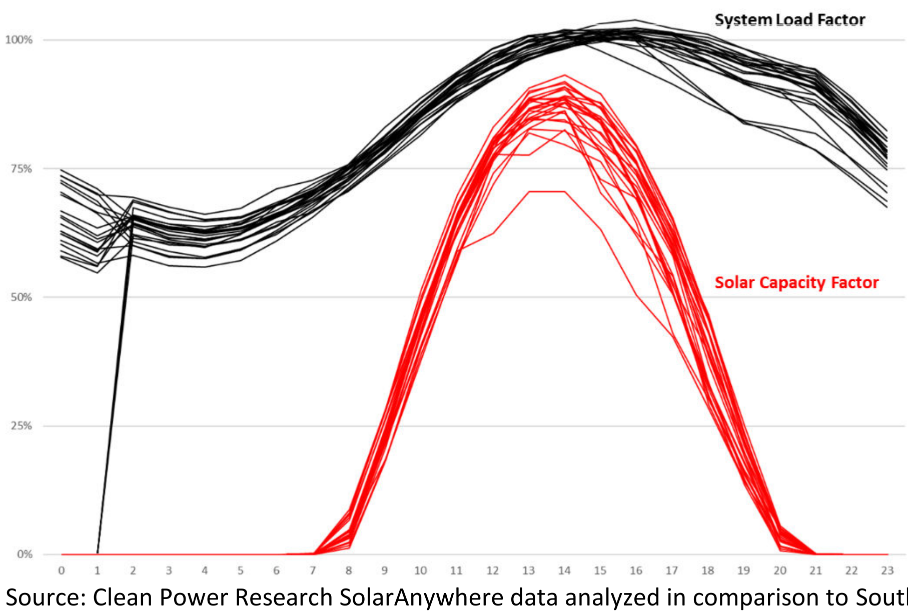
Figure 1: SCE&G load factor vs. solar capacity factor, August 2015



Source: Clean Power Research SolarAnywhere data analyzed in comparison to South Carolina Electric & Gas data filed on FERC Form 714 for 2015.

On peak days, however, solar capacity factors show a much higher consistency of output. In Figure 2, below, solar generation for the same average fixed mount system is shown for the top 25 peak days from 1998-2015. On peak days, solar generation is much more consistent, with only one instance of diminished output (July 8, 1998) like those seen in Figure 1. This makes intuitive sense because cloudy days tend to be more moderate in temperature, and loads are highest in the summer on sunny days.

Figure 2: SCE&G load factor vs. solar capacity factor, peak load days 1998-2015



Source: Clean Power Research SolarAnywhere data analyzed in comparison to South Carolina Electric & Gas data filed on FERC Form 714 for 1998-2015. Anomalous data from source file obtained from FERC.

Another way in which SCE&G's critical peak period method inappropriately includes many off-peak hours is by allocating 80% of capacity value to the summer period and 20% to the winter peak period. As demonstrated by the data in Tables 2 and 3, only 5-6% of peak hours occur in the winter peak period. By excessively weighting the winter peak period at 20%, the SCE&G PR-1 and PR-2 tariffs effectively overemphasize many winter hours in which loads fall far short of system peaks, thus overemphasizing hours without any significant reliability risk in the calculation.

(4) Impact of SCE&G's critical peak period on capacity equivalent values

Table 4, below, illustrates the impact of SCE&G's method on the capacity equivalent value. The capacity factor is calculated for all hours, SCE&G's critical peak hours, and actual system peak hours (top 1% of hours ranked by system load factor).

Table 4: Seasonal capacity factors by peak hour selection method, SCE&G 1998-2015

	Fixed Mount PV System	Single Axis Tracking PV System
Summer (June-September)		
All Hours	23.7 %	29.8 %
Critical Peak Hours	54.4 %	64.2 %
System Peak Hours	66.1 %	74.2 %
Winter (December-March)		
All Hours	19.1 %	20.5 %
Critical Peak Hours	9.2 %	18.2 %
System Peak Hours	3.1 %	6.5 %

Source: Clean Power Research SolarAnywhere data analyzed in comparison to South Carolina Electric & Gas data filed on FERC Form 714 for 1998-2015.

Based on these data, it appears that solar performs about 10-12% better during summer system peak hours than it does during SCE&G's summer critical peak hours. In the winter, solar performs about 6-12% worse during winter system peak hours than during the winter critical peak hours. However, as noted earlier, SCE&G's system history is dominated by summer peaks: Using the top 1% load factor threshold, about 95% of all peak hours occur during summer months.

Further analysis of these data indicate that the majority of the difference between the critical peak hours method and the system peak hours method can be explained by the inclusion of many hours in which system peak loads are not observed. Performing the system peak hours method calculation on just the critical peak period results in about a 1% change in the result for most technologies.[15] Thus, while the excluded hours are significant from a reliability assessment perspective, the performance of solar during those hours is not very different from the performance of solar during on-peak hours that happen to occur during the critical peak period.

(5) Consideration of different PV technologies by SCE&G's critical peak period method

Notwithstanding these problems with the critical peak hours method, its technology-neutral approach does give due consideration to the enhanced on-peak performance of certain PV generation technologies. As shown in Table 4, application of the critical peak hours method does recognize single axis tracking systems as providing more capacity during peak hours.

To further explore the potential impact of technology choice on capacity equivalent value, Clean Power Research provided data on a variety of PV system configurations reflecting a range of differing system deployments. With the exception of the west facing fixed mount system design, all system design configurations tested similarly to the other systems of the same technology class, as shown in Table 5.

Table 5: Performance of various solar PV system technologies, SCE&G 1998-2015

	Annual Capacity Factor	Capacity Equivalent Value	
		Winter	Summer
Fixed Mount PV Systems			
South facing, 20° tilt, 130 % DC/AC	21.7 %	2.9 %	66.6 %
South facing, 25° tilt, 115 % DC/AC	21.8 %	3.1 %	66.1 %
South facing, 25° tilt, 130 % DC/AC	21.7 %	2.9 %	66.6 %
West facing, 25° tilt, 130 % DC/AC	18.4 %	0.6 %	67.6 %
Single Axis Tracking Systems			
115 % DC/AC	25.7 %	6.5 %	74.4 %
130 % DC/AC	25.7 %	6.5 %	74.2 %
145 % DC/AC	25.6 %	6.5 %	74.1 %

Source: Clean Power Research SolarAnywhere data analyzed in comparison to South Carolina Electric & Gas data filed on FERC Form 714 for 1998-2015.

[15] West facing fixed mount systems should receive a higher capacity equivalent value than a south facing system. South facing systems tested at 54-55%, but the west facing system tested at 62%. The critical peak hours method should provide a portion of this value spread, as it undervalues solar capacity by only 6%, compared to an undervaluation of 12% for south facing systems.

C. Recommended improvements to solar capacity equivalence method

In summary, neither the simple 50% capacity equivalent factor used in the SCE&G IRP nor the more nuanced critical peak hours method fully capture the enhanced performance of solar on summer peak days. These practices undervalue the contribution of solar power to summer peak loads by as much as 24%. The system peak hours method used in this study includes peak hours excluded by SCE&G's methods, excludes non-peak hours included by SCE&G's method, and considers the impact of solar PV technology selection (which is not considered in SCE&G's IRP capacity equivalence values).

The shortcomings of the critical peak hour method are explained both by the omission of peak load hours that occur outside the SCE&G critical peak period, as well as the inclusion of load hours that occur during the critical peak period, but represent lower-than-peak system demand. These shortcomings could be addressed by shifting to different methods for both planning and tariff design. For example, SCE&G could revise its tariff to include an adjustment factor to align its critical peak hours method with the results shown in Table 1. A more nuanced approach would be to utilize an effective load carrying capacity (ELCC) calculation or an incremental capacity equivalent (ICE) calculation. The ELCC and ICE methods have been adopted by other utilities in order to evaluate the contribution of solar and other variable energy resources by placing the greatest weight on time periods with the highest reliability risks. Until some improvement is made, SCE&G's understatement of the capacity equivalence value of solar will continue to undervalue solar capacity both from a tariff perspective as well as from a resource planning perspective.

Notes on the Clean Power Research Data Used in This Analysis

The solar systems analyzed for this report were modeled by Clean Power Research using the SolarAnywhere Standard Resolution resource data. Although the modeled data cover 1998-2016, FERC Form 714 data are currently available only through 2015, and thus 2016 data are not analyzed in this report. SACE selected six of the modeled systems using two of the modeled technology for analysis in this report. The annual capacity factors and capacity equivalent values for each PV site on the South Carolina Electric & Gas system are provided in Table 6.

Documentation for the data modeled by Clean Power Research is attached.

Table 6: Fixed mount and single axis tracking system solar performance on South Carolina Electric & Gas system

	Annual Capacity Factor	Capacity Equivalent Value Capacity Factor During Top 1% System Load Factor Hours		
		Annual	Summer	Winter
Fixed South 25-115	**21.8%**	**63.1%**	**66.1%**	**3.1%**
Plant McIntosh, GA	22.0%	63.4%	66.4%	3.2%
Plant Vogtle, GA	21.6%	62.3%	65.3%	2.8%
Richard B Russell Dam, GA	21.9%	63.5%	66.5%	2.9%
Dover, GA	22.0%	64.0%	67.1%	2.9%
Lumberton, NC	21.7%	61.6%	64.5%	3.8%
Greenville, SC	21.9%	64.0%	67.0%	2.8%
Hagood Gas Plant, SC	22.1%	62.8%	65.7%	3.5%
Anderson, SC	22.1%	65.3%	68.5%	2.8%
McMeekin Coal Plant, SC	21.8%	64.3%	67.4%	3.1%
Spartanburg, SC	21.9%	63.2%	66.2%	2.6%
Pickens, SC	21.8%	63.4%	66.4%	2.6%
Plant Robinson, SC	21.5%	60.7%	63.6%	3.2%
Lancaster, SC	21.7%	62.3%	65.4%	2.9%
Johnsonville, SC	21.7%	63.0%	65.9%	3.8%
Tracking 130	**25.7%**	**70.9%**	**74.2%**	**6.5%**
Plant McIntosh, GA	26.1%	71.8%	75.1%	6.8%
Plant Vogtle, GA	25.5%	70.3%	73.5%	5.6%
Richard B Russell Dam, GA	25.8%	71.3%	74.6%	6.2%
Dover, GA	26.0%	72.3%	75.6%	6.0%
Lumberton, NC	25.5%	69.5%	72.5%	8.6%
Greenville, SC	25.8%	71.2%	74.5%	5.6%
Hagood Gas Plant, SC	26.2%	71.3%	74.4%	7.5%
Anderson, SC	26.1%	73.0%	76.3%	5.9%
McMeekin Coal Plant, SC	25.7%	72.3%	75.6%	6.7%
Spartanburg, SC	25.7%	70.1%	73.4%	5.4%
Pickens, SC	25.5%	70.3%	73.6%	5.4%
Plant Robinson, SC	25.3%	68.2%	71.3%	6.9%
Lancaster, SC	25.6%	70.1%	73.4%	6.2%
Johnsonville, SC	25.6%	71.4%	74.5%	8.3%

Source: Clean Power Research SolarAnywhere data analyzed in comparison to South Carolina Electric & Gas data filed on FERC Form 714 for 1998-2015. Sites included in this analysis include all sites in South Carolina, plus Georgia and North Carolina sites located close to the border. The six sites most closely associated with the SCE&G service territory are Plant McIntosh, Plant Vogtle, Lumberton, McMeekin Coal Plant, Plant Robinson, and Johnsonville.

Clean Power Research®

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Clean Power Research (CPR) has completed its hourly simulations for seven PV system configurations at each of 147 locations using its SolarAnywhere modeling services. The PV production datasets for these 1,029 systems may be scaled and aggregated by SACE as needed.

We have provided simulated PV production for each hour from January 1, 1998 through December 31, 2016 using the local SolarAnywhere Standard Resolution (approximately 10 km x 10 km x 1 hour resolution) resource data corresponding to the system location. CPR has provided a description of the data and details of the system configurations in the Appendix.

Sincerely,

Philip Gruenhagen

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Consulting Engineer

Appendix

System Specifications

Table 1 lists the specifications for the seven PV systems that CPR modeled at each location. Each system has a 1.0 MW AC rating with losses. CPR designed the fixed system configurations to highlight differences due to three attributes: tilt, DC to AC ratio, and azimuth. Tracking system configurations only vary in DC to AC ratio. All three tracking systems are horizontal (0° tilt) and have a tracking rotational limit of +/- 52°. The tracking systems are identical except for the inverter AC maximum power rating, which we adjusted to provide the three different DC to AC ratios.

We configured all systems with 5,333 modules. Each module was rated at 250.1 Watts DC_{STC} (225 Watts DC_{PTC}), making the combined system rating 1,334 kW DC_{STC} (1,200 kW DC_{PTC}). Multiplying the 1,200 kW DC_{PTC} rating by the 98% average inverter efficiency rating yields a CEC-AC rating of 1,176 kW AC_{CEC}. After applying a general derate factor of 85% to account for other DC losses, we arrive at a rating of 1,000 kW (1.0 MW) AC with losses.

CPR laid out the arrays using 30 rows for fixed systems and 60 rows for tracking systems and a relative row spacing of 2.0. Relative row spacing does not indicate the absolute distance in feet or meters, but instead indicates the distance as a proportion of the height of the array, as shown in Figure 1.

Figure 1 - Relative Row Spacing

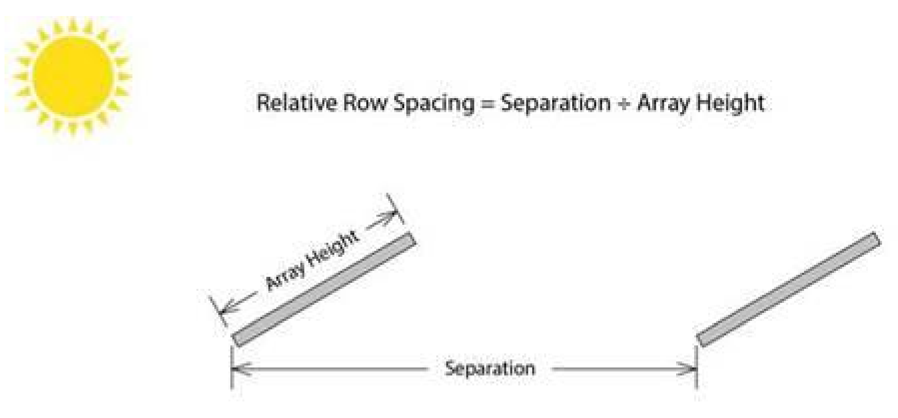


Table 1 - PV System Configurations

	Fixed South 20-130	Fixed South 25-115	Fixed South 25-130	Fixed West 25-130	Tracking 115	Tracking 130	Tracking 145
Module Specifications							
Module Count	5,333	5,333	5,333	5,333	5,333	5,333	5,333
Module Rating (Watts DC_{STC})	250.1	250.1	250.1	250.1	250.1	250.1	250.1
Module NOCT	45.0° C	45.0° C	45.0° C	45.0° C	45.0° C	45.0° C	45.0° C
Efficiency Reduction (% per °C)	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Ventilation Quality	Average	Average	Average	Average	Average	Average	Average
Annual Degradation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PV Array Specifications							
System STC Rating (kW DC_{STC})	1,334	1,334	1,334	1,334	1,334	1,334	1,334
Module Derate (PTC/STC Ratio)	90%	90%	90%	90%	90%	90%	90%
System PTC Rating (kW DC_{PTC})	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Inverter AC Max Power (kW)	1,025	1,159	1,025	1,025	1,159	1,025	920
DC_{STC} to Inverter AC Ratio	130%	115%	130%	130%	115%	130%	145%
Inverter Efficiency Rating	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
AC_{CEC} Rating (kW AC_{CEC})	1,176	1,176	1,176	1,176	1,176	1,176	1,176
General Derate Factor	85%	85%	85%	85%	85%	85%	85%
AC Rating with Losses (kW AC)	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Albedo	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Installation Specifications							
Array Azimuth[1,2]	180°	180°	180°	270°	180°	180°	180°
Module Row Count	30	30	30	30	60	60	60
Relative Row Spacing	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Array Tilt[3]	20°	25°	25°	25°	0°	0°	0°
Tracking Rotation Limit	n/a	n/a	n/a	n/a	+/- 52°	+/- 52°	+/- 52°

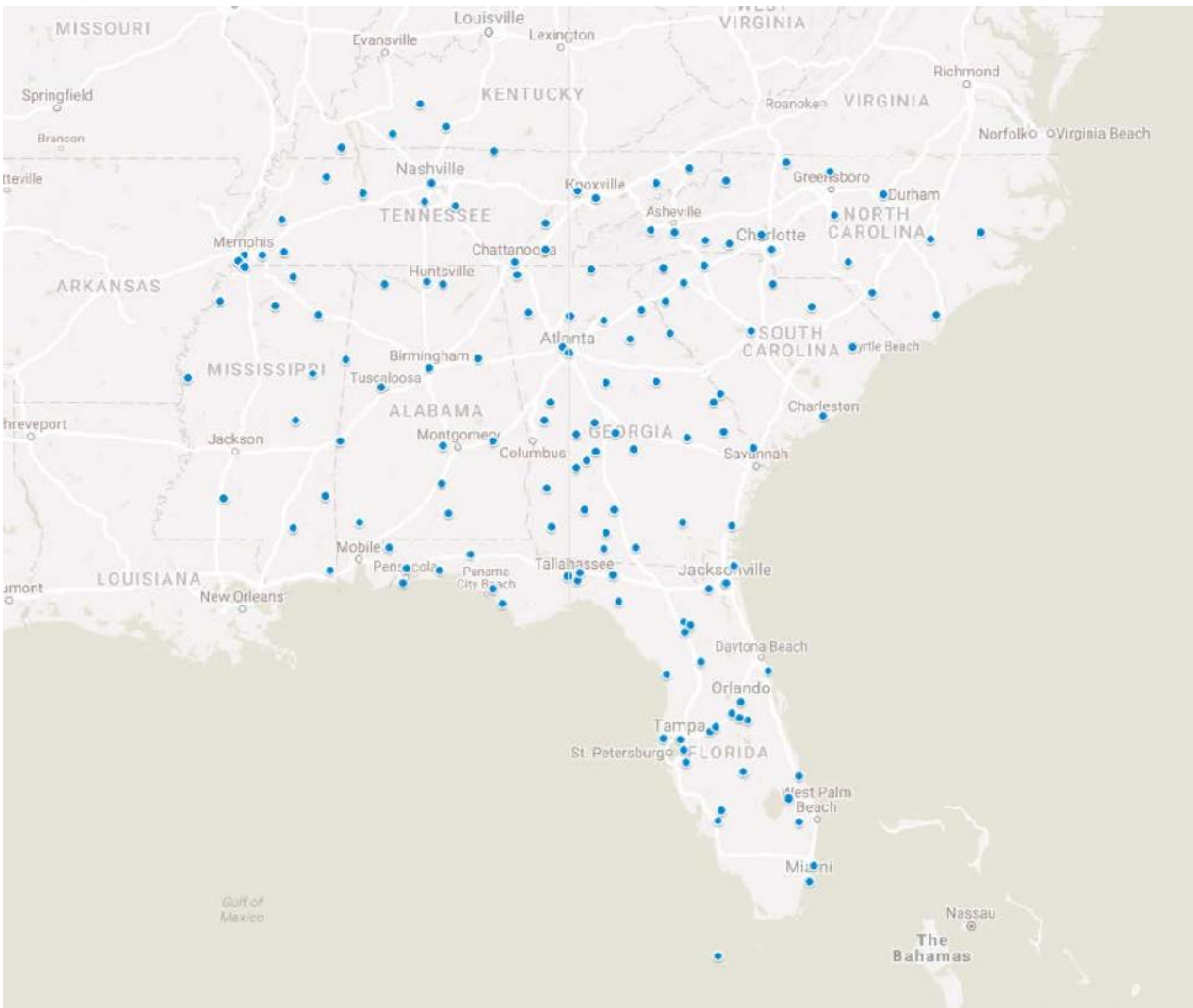
[1] Tracking systems are aligned north-south, tracking east-west.
[2] Solar south is 180°
[3] 0° is horizontal, 90° is vertical

System Locations

SACE provided a list of 147 locations, as shown in Figure 2. The system locations are provided in list form in Table 2. CPR modeled each of the seven system configurations at each of the locations listed.

A KMZ file for the system locations is also available. You can use this file with tools like Google Earth to visualize the location of the simulated systems (as shown in Figure 2).

Figure 2 - Map of System Locations



Modeling Results Data Files

The simulated hourly PV production data is available in individual comma separated values (CSV) format files for each system. Most spreadsheet programs can open CSV files. We've named the 1,029 files based on the location ID and system configuration. For example, you can find the results for the Fixed South 20-130 configuration modeled at Huntsville Downtown, AL (location ID A01) in the file named, "A01 Fixed South 20-130.csv." To save space and reduce download times, the CSV files have been compressed into a single WinZip archive named, "SimulationResults.zip."

There are five columns in each CSV file. The first (leftmost) two columns provide the start and end time of the period that the energy value in the third column corresponds to. All time stamps are in standard time for the locale where the system was located, with a UTC offset to indicate whether the time stamp is Eastern Standard Time (UTC -5:00) or Central Standard Time (UTC -6:00). Time stamps in these files do not use Daylight Saving Time.

Energy values are in kWh AC for each hour (equivalent to average kW AC per hour). The fourth column contains the ambient temperature for the period in degrees Celsius and the last column contains the observation type for the period, where AN means, "Archive Night," AD means, "Archive Day," and AM means, "Archive Missing." [4]

Clean Power Research makes use of satellite-derived irradiance data for PV modeling. When satellite imagery at some location is unavailable for one or more periods, the observation type will end with the letter 'M.' In this case, the energy value for that period should be considered invalid. A complete list of missing periods for each location is available in the file named, "MissingPeriods.xlsx."

Table 2 – System Locations

ID	Name	State	Latitude	Longitude
A01	Huntsville Downtown, AL	AL	34.73	-86.58
A02	Muscle Shoals, AL	AL	34.74	-87.6
A03	Chickamauga, GA	GA	34.87	-85.27
A04	Paradise Fossil Plant, KY	KY	37.2597	-86.9781
A05	Magnolia Power Plant CC, MS	MS	34.8353	-89.2018

[4] For a full list of irradiance observation type prefixes and suffixes, see https://www.solaranywhere.com/validation/data/file-formats/

A06	Oxford, MS	MS	34.42	-89.52
A07	Philadelphia, MS	MS	32.75	-89.15
A08	Gleason Power Plant CT, TN	TN	36.2451	-88.6121
A09	Johnson City, TN	TN	36.37	-82.3
A10	Oak Ridge, TN	TN	36.05	-84.25
A11	Murray, KY	KY	36.65	-88.35
A12	Cordova, TN	TN	35.14	-89.74
A13	Murfreesboro, TN	TN	35.85	-86.35
A14	Bowling Green, KY	KY	36.94	-86.52
A15	Hopkinsville, KY	KY	36.85	-87.45
A16	Tupelo, MS	MS	34.29	-88.76
A17	Starkville, MS	MS	33.45	-88.85
A18	Memphis Downtown, TN	TN	35.15	-90.05
A19	Nashville Downtown, TN	TN	36.16	-86.78
A20	Knoxville Downtown, TN	TN	35.96	-83.92
A21	Chattanooga Downtown, TN	TN	35.05	-85.31
A22	Cleveland, TN	TN	35.22	-84.79
A23	Caledonia CC, MS	MS	33.6478	-88.2721
A24	Lagoon Creek CT-CC, TN	TN	35.6532	-89.3937
A25	Johnsonville Fossil Plant, TN	TN	36.0278	-87.9864
A26	Watts Bar, TN	TN	35.6023	-84.7896
B08	Washington County CoGen Facility, AL	AL	31.2542	-88.0319
B09	E B Harris Electric Generating Gas Plant, AL	AL	32.3814	-86.5736

B10	Crist Coal Plant, FL	FL	30.5653	-87.2248
B11	Lansing Smith Coal and Gas Plant, FL	FL	30.2689	-85.7003
B12	Plant McIntosh, GA	GA	32.3562	-81.1686
B13	Deerhaven Generating Station, FL	FL	29.7589	-82.388
B14	Plant Mitchell, GA	GA	31.4447	-84.132
B15	Robins Gas Plant, GA	GA	32.5806	-83.5831
B16	Plant McManus, GA	GA	31.2125	-81.5458
B17	Plant Vogtle, GA	GA	33.1418	-81.7621
B18	Jack McDonough Plant, GA	GA	33.8228	-84.4757
B19	Plant Daniel, MS	MS	30.5335	-88.5574
B20	Brookhaven, MS	MS	31.62	-90.41
B21	Crystal River Nuclear Plant, FL	FL	28.9671	-82.6991
B22	West County Energy Center Gas Plant, FL	FL	26.6862	-80.3801
B23	Tampa Downtown, FL	FL	27.95	-82.46
B24	Fort Myers Gas Plant, FL	FL	26.6967	-81.7831
B25	Orlando Downtown, FL	FL	28.54	-81.39
B26	Arvah B Hopkins Gas Plant, FL	FL	30.4522	-84.4
B27	Miami Downtown, FL	FL	25.76	-80.19
B28	Jacksonville Downtown, FL	FL	30.35	-81.66
B29	L V Sutton Coal Plant, NC	NC	34.2828	-77.9861
B30	Shelby, NC	NC	35.31	-81.59
B31	HF Lee Power Plant, NC	NC	35.3734	-78.09
B32	Rockingham County CT Station, NC	NC	36.3302	-79.8285

B33	Durham Downtown, NC	NC	36	-78.9
B34	Lumberton, NC	NC	34.61	-79.09
B35	Lincoln CT Plant, NC	NC	35.4317	-81.0347
B36	Asheville Power Plant, NC	NC	35.4712	-82.5415
B37	Greenville, SC	SC	34.75	-82.39
B38	Hagood Gas Plant, SC	SC	32.8263	-79.9613
B39	Anderson, SC	SC	34.49	-82.72
B40	McMeekin Coal Plant, SC	SC	34.0556	-81.2167
C01	Huntsville West, AL	AL	34.76	-86.86
C02	Plant Allen, TN	TN	35.06	-90.15
C03	Plant Southaven, MS	MS	34.98	-90.04
C04	Franklin, TN	TN	35.9	-86.9
C05	Pensacola NAS, FL	FL	30.35	-87.27
C06	Walnut Hill, FL	FL	30.88	-87.51
C07	Tyndall AFB, FL	FL	30.04	-85.53
C08	Eglin AFB, FL	FL	30.53	-86.64
C09	Defuniak Springs, FL	FL	30.78	-86.1
C10	Plant McWilliams, AL	AL	31.4	-86.48
C11	Butler, GA	GA	32.56	-84.27
C12	Waycross, GA	GA	31.26	-82.41
C13	Atlanta Downtown, GA	GA	33.75	-84.39
C14	Big Bend Power Station, FL	FL	27.7974	-82.3963
C15	Hollywood Beach, FL	FL	26.01	-80.12

C16	Ft Pierce, FL	FL	27.39	-80.37
C17	Babcock Ranch, FL	FL	26.86	-81.74
C18	Martin Power Plant, FL	FL	27.05	-80.56
C19	Parrish Power Plant, FL	FL	27.6053	-82.352
C20	CD McIntosh Power Plant, FL	FL	28.0828	-81.9234
C21	Perry, FL	FL	30.07	-83.53
C22	Swainsboro, GA	GA	32.51	-82.34
C23	Spartanburg, SC	SC	34.99	-82.04
C24	Rutherfordton, NC	NC	35.36	-82.01
C25	Pickens, SC	SC	34.96	-82.75
C26	Gainesville, GA	GA	34.2	-83.78
C27	Canon, GA	GA	34.35	-83.13
C28	Athens, GA	GA	33.95	-83.34
C29	Blairsville, GA	GA	34.95	-84
C30	Canton, GA	GA	34.28	-84.37
C31	Rome, GA	GA	34.33	-85.09
C32	Waynesboro, MS	MS	31.65	-88.64
C33	Birmingham Downtown, AL	AL	33.52	-86.81
C34	Anniston Army Depot, AL	AL	33.66	-85.95
C35	Greenville, NC	NC	35.47	-77.2
C36	Sparta, GA	GA	33.32	-82.88
C37	Plant Robinson, SC	SC	34.401	-80.1591
C38	Lancaster, SC	SC	34.73	-80.84

C39	Johnsonville, SC	SC	33.82	-79.43
C40	Greenville, GA	GA	33.02	-84.71
C41	Richard B Russell Dam, GA	GA	34.02	-82.63
C42	Mt Airy, NC	NC	36.46	-80.6
C43	Bulldozer Rd, TN	TN	36.61	-85.67
C44	Camp Mackall, NC	NC	35.04	-79.51
C46	Tuscaloosa, AL	AL	33.24	-87.65
C47	Cuba, AL	AL	32.45	-88.37
C48	Camp Shelby, MS	MS	31.18	-89.19
C49	Sebring, FL	FL	27.46	-81.35
C50	Valdosta, GA	GA	30.88	-83.23
C51	Monticello, GA	GA	33.31	-83.74
C52	Lula, MS	MS	34.48	-90.47
C53	Tuskeegee, AL	AL	32.46	-85.69
C54	Boone, NC	NC	36.2	-81.66
C55	Waynesboro, NC	NC	35.51	-82.97
C56	Asheboro, NC	NC	35.72	-79.76
C57	Charlotte Downtown, NC	NC	35.22	-80.85
C58	Key West, FL	FL	24.58	-81.8
C59	Greenville, MS	MS	33.37	-91.03
C60	Greenville, TN	TN	36.16	-82.88
C61	Greenville, FL	FL	30.47	-83.62
C62	Greenville, AL	AL	31.83	-86.6

C63	Clearwater, FL	FL	27.98	-82.76
C64	New Smyrna Beach, FL	FL	29.02	-80.92
C65	Tallahassee Southwood, FL	FL	30.39	-84.24
C66	Tallahassee Killearn, FL	FL	30.51	-84.2
C67	Gainesville, FL	FL	29.61	-82.38
C68	Gainesville Airport, FL	FL	29.7	-82.27
C69	Disney World, FL	FL	28.37	-81.56
C70	Polk City, FL	FL	28.15	-81.83
C71	St. Cloud, FL	FL	28.25	-81.28
C72	Fernandina Beach, FL	FL	30.61	-81.52
C73	Baldwin, FL	FL	30.27	-81.95
C74	Kissimmee, FL	FL	28.29	-81.41
C75	Ocala, FL	FL	29.16	-82.09
D01	Cuthbert, GA	GA	31.7665	-84.7623
D02	Alexander, GA	GA	33.025	-81.8811
D03	Dover, GA	GA	32.591	-81.6997
D04	Empire, GA	GA	32.3443	-83.2763
D05	Montezuma, GA	GA	32.3016	-83.9228
D06	Colquitt, GA	GA	31.1871	-84.6893
D07	Americus, GA	GA	32.0602	-84.2643
D08	Tifton, GA	GA	31.45	-83.6
D09	Thomasville, GA	GA	30.87	-83.79
D10	Roberta, GA	GA	32.73	-83.94

D11	Hamilton, GA	GA	32.76	-84.8
D12	Andersonville, GA	GA	32.16	-84.09
D13	Moultrie, GA	GA	31.1	-83.74
D14	Somerville, TN	TN	35.19	-89.36