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DEC / DEP Joint Exhibit 11

DEC's and DEP's 2021 Solar Integration Service Charge Study prepared by Astrapé Consulting

Docket No. E-100, Sub 175

ASTRAPÉ CONSULTING
innovation in electric system planning

Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study

10/22/2021

PREPARED FOR

Duke Energy

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Executive Summary

The Solar Integration Service Charge (SISC) Study is the second SISC Study performed by Astrapé Consulting for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) referred to herein as the Companies. The first study was conducted in 2018. As part of this second study, the Companies, with input from the North Carolina Public Staff (NCPS) and South Carolina Office of Regulatory Staff (ORS), retained The Brattle Group ("Brattle") as Technical Review Committee (TRC) Principal consultant. Brattle coordinated TRC meetings to review the findings in this report, incorporated feedback from the TRC Technical Leads, and will separately author a TRC report for the Companies to incorporate in their 2021 regulatory filings. In addition to Brattle, the TRC consisted of regulatory observers from the NCPS, ORS, and technical leads from the national labs mentioned on page 2. The TRC provided significant feedback and recommendations during a bi-weekly review process which commenced in March 2021 and concluded in July of 2021. These were reflected in the Study as discussed throughout this report.

As DEC and DEP continue to add solar to their systems, understanding the impact the solar fleet has on real time operations is important. Due to the intermittent nature of solar resources and the requirement to meet real time load on a minute-to-minute basis, online dispatchable resources need to have enough flexibility to ramp up and down to accommodate unexpected movements in solar output. Not only can solar drop off quickly but it can also ramp up quickly. Unexpected movement in either direction causes system ramping needs. When solar output drops off quickly, reliability can be an issue if other generators are not able to ramp up fast enough to replace the lost solar energy. When solar ramps up quickly, if other generators are not able to ramp down to match the solar output change, some solar generation may need to be curtailed. At low solar penetrations, the unexpected changes in solar output can be cost effectively accommodated by increasing upward ancillary service[1] targets within the existing conventional fleet. Increasing ancillary service targets forces the system to commit more generating resources which allows generators to dispatch at lower levels giving them more capability to ramp up. There is a cost to this increase in ancillary services because generators are operated less efficiently when they are dispatched at lower levels. Generators may also start more frequently which also increases costs. As solar penetrations continue to rise, carrying additional ancillary services to mitigate solar uncertainty with the conventional fleet becomes more expensive. This Study analyzes multiple solar penetration levels and quantifies the cost of utilizing the existing fleet to reliably integrate the additional solar generation.

For this Study, the Strategic Energy and Risk Valuation Model (SERVM) was utilized because it not only performs intra-hour simulations which include full commitment and dispatch logic, but also because its commitment and dispatch decisions can be performed against uncertain net load forecasts. This uncertainty results in flexibility excursions defined as an event where the online generation fleet is not able to ramp fast enough to match upward net load perturbations. These flexibility excursions are not expected to represent firm load shed events, but rather are simply a measure of the fleet's ability to follow net load changes given a particular set of operating guidelines. At each solar penetration level, simulations were performed assuming the same ancillary service inputs that are used in SERVM simulations with zero solar capacity. The number of flexibility excursions were recorded from those simulations. Next, total flexibility excursions with solar generation were calibrated to the same level as in the zero solar simulations by increasing ancillary services in the form of load following reserves. The goal of the Study is to maintain the same ability to follow net load as demonstrated in the no solar base case in any solar

[1] Ancillary services are defined in further detail in the Input Section of the Report but for purposes of this Study, load following, which is represented by 10-minute system ramping capability, was used to resolve flexibility gaps.

penetration level analyzed. Finally, system costs were compared between operating with the zero-solar baseline ancillary services (lower cost, but more flexibility excursions) to operating with the higher-solar load following requirements (higher cost but achieves the same level of flexibility excursions that existed before the solar was added). The difference in cost is allocated to the solar energy and represents the Solar Integration Services Charge (SISC). The SISC was estimated for both an "island case," which assumes DEC and DEP need to follow their respective loads with their own resources and a "combined case", which approximates the joint dispatch agreement under which DEC and DEP are currently operating as recommended by the TRC.

Two levels of solar penetrations were modeled for both DEC and DEP as shown in Table ES-1. The solar penetration scenarios reflect a range of solar capacity that would cover the Companies' expectations over the next 3-5 years consistent with the 2024 Study year. Calculating the SISC for these levels provides the Companies with a SISC value as a function of solar penetration to be used in setting the SISC. The Appendix includes a third (even higher) tranche of solar generation, which was simulated but is not relevant to the current effort of setting the SISC due to solar capacity levels modeled that exceed the levels DEC and DEP will reach in the next several years.

Table ES-1. DEC and DEP Solar Penetrations Analyzed

	DEC MW	DEP MW
Tranche 1	976	2,908
Tranche 2	2,431	4,019

Table ES-2 shows the results of the island cases for both DEC and DEP which were used to determine the load following requirements for each Company. As solar generation is added, net load volatility increases, causing flexibility excursions to increase. To reduce the excursions, additional load following is added across the day, which is discussed in detail later in the report. SERVM then commits to the higher load following target which causes an increase in costs. For DEC, the results show that as solar increases from 0 MW to 967 MW, on average 12 MW of additional load following across the daytime hours is required to maintain the same number of excursions that occurred in the 0 MW solar scenario. When tranche 2 is added to the analysis, which includes 2,431 MW, 46 MW of additional load following on average across daytime hours is required compared to the 0 MW solar case. Similar patterns are seen in DEP, as shown in Table ES-3. Tranche 1, which assumes 2,908 MW of solar capacity, requires 95 MW of additional load following on average across daytime hours. Tranche 2 which, assumes 4,019 MW of solar capacity, requires 157 MW of additional load following on average across daytime hours.

Table ES-2. DEC Island Results

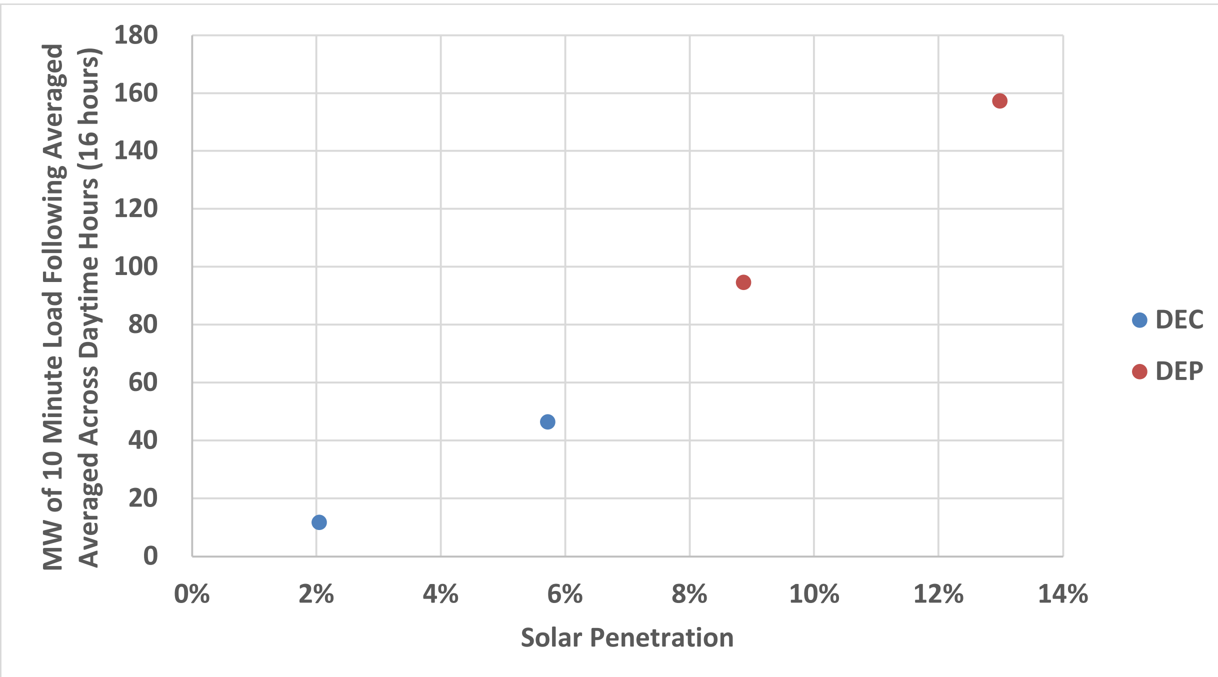
	DEC No Solar	DEC Tranche 1	DEC Tranche 2
Total Solar (MW)	0	967	2,431
Flexibility Violations (Events Per Year)	2.6	2.6	2.6
Realized 10-Minute Load Following Reserves (Average MW Over Daytime Hours Assuming 16 Hours) (MWh)	0	12	46

Table ES-3. DEP Island Results

	DEP No Solar	DEP Tranche 1	DEP Tranche 2
Total Solar (MW)	0	2,908	4,019
Flexibility Violations (Events Per Year)	0.6	0.6	0.6
Realized 10-Minute Load Following Reserves (Average MW Over Daytime Hours Assuming 16 Hours) (MWh)	0	95	157

Figure ES-1 shows the load following increase as a function of solar penetration for both DEC and DEP.

Figure ES-1. Quantified Required Increase in Load Following Reserves as a Percentage of Solar Penetration



As requested by the TRC, the Study simulated the Joint Dispatch Agreement (JDA) between the DEC and DEP balancing areas to determine the SISC.[2] The combined JDA results reflect modeling the DEC and DEP balancing areas simultaneously with transmission capability between them.

In these simulations, the realized load following additions determined in the island case with separate balancing areas were targeted for the combined case except now economic transfers can be made on a 5-minute basis. These economic transfers reduce system costs and in turn reduce integration costs. In

[2] The island SISC costs were also calculated and are shown in the body of the report.

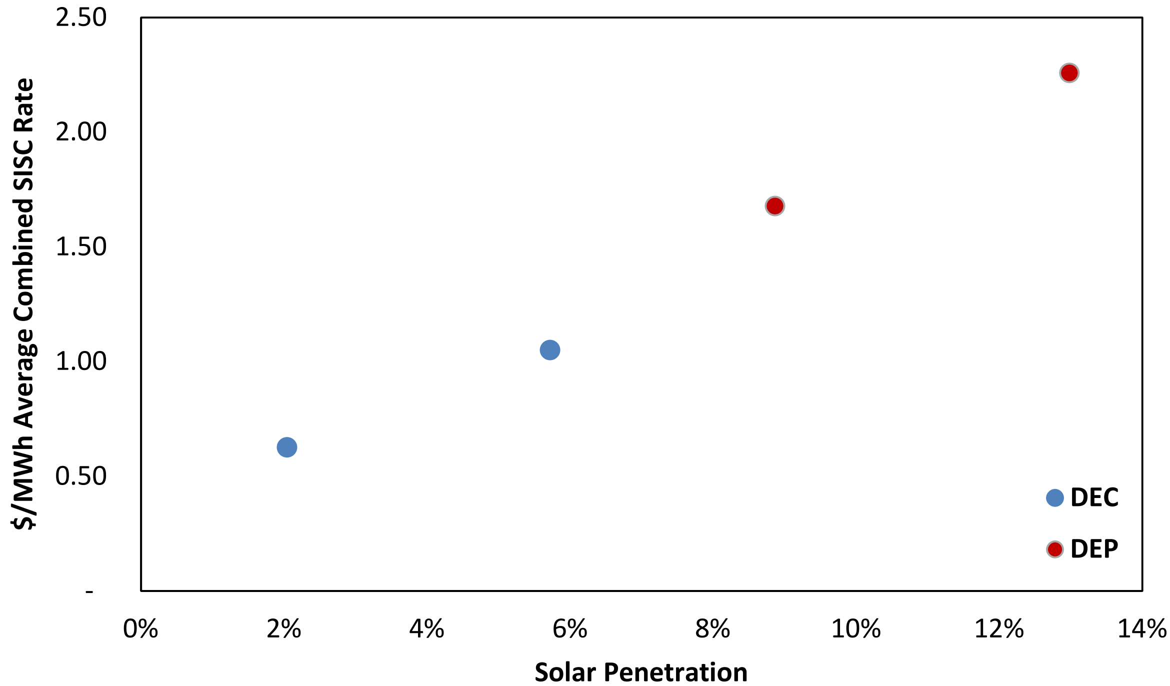
discussions with the Companies' operators, this method is potentially optimistic because SERVM has perfect foresight within the 5-minute time step to dispatch generation in both zones to perfectly minimize system production costs, whereas the JDA may be subject to more uncertainty and less dispatch flexibility. The results are shown in the following table. As expected, there are savings versus the island scenario as discussed in the body of the report. These benefits then have to be allocated to each Companies' integration cost. Astrapé along with the TRC and the Companies determined it was most appropriate to allocate the benefit based on the rated cost of load following (in $/MWh) from the combined analysis compared to the island results. Table ES-4 shows the load following cost rate as well as the average and incremental SISC rates based on the JDA simulations. The load following cost rate is the total production cost increase divided by the additional 10-minute load following reserves that are increased. The SISC rates for both DEC and DEP are lower in the combined case than in the island cases.

Table ES-4. Combined Results with Load Following Cost Allocation

	DEC Tranche 1	DEP Tranche 1	Combined Tranche 1	DEC Tranche 2	DEP Tranche 2	Combined Tranche 2
Solar Capacity (MW)	967	2,908	3,875	2,431	4,019	6,450
Solar Generation (MWh)	1,887,513	5,677,206	7,564,719	5,279,071	8,312,634	13,591,705
Combined (JDA Modeled) 10-Minute Load Following Cost Rate ($/MWh)	17.25	17.25	17.25	20.45	20.45	20.45
Average SISC with Combined (JDA Modeled) Load Following Rates ($/MWh)	0.63	1.68	1.42	1.05	2.26	1.79
Incremental SISC with Combined (JDA Modeled) Load Following Rates ($/MWh)	0.63	1.68	1.42	1.29	3.51	2.26

Figure ES-2 shows the average SISC for both tranches by Company for the combined cases.

Figure ES-2. Average Combined SISC Rates for Tranche 1 and 2



These SISC average and incremental rates across these tranches provide the Companies with information to determine a rate to be used in its avoided cost filing. There are average and incremental rates across a wide range of solar penetrations. The rates are highly correlated with the solar penetration as seen in Figure ES-2 so SISC rates for any penetration level can be deduced from the analysis.

Key Changes to Study Methodology from 2018 Study

Working with the TRC, incorporating feedback from the 2018 Study, and applying lessons learned from other renewable integration studies performed by Astrapé, the Study incorporated a number of key changes to its methodology. First, since the industry does not have a standard for modeled flexibility excursions, the targeted flexibility excursions for this study was changed to the number of flexibility excursions from the pre-solar case for each of the Companies. In the 2018 Study, flexibility excursions were targeted to 0.1 events per year.[3] Since the pre-solar case was setup to mimic the Companies' standard operating practices, maintaining the base case flexibility excursions in each solar penetration scenario is appropriate. While these varied by Company, they were higher than the value from the 2018 Study. Second, the 2018 Study added flat blocks of operating reserves to eliminate flexibility excursions. While additional overnight operating reserve targets isn't expected to significantly affect commitment[4], the study recognizes that the introduction of solar does not change the volatility of net load in non-solar hours, and so changes in operating reserve targets should only be added across the daytime hours to manage solar volatility and ramps. Finally, the recommended SISC is based on the production cost savings from the combined commitment and dispatch of the DEC and DEP systems. In this study, the rated cost of load following from the combined case is used to calculate the individual Company's SISC, reducing costs from the scenario where each Company is simulated as an island.

The following sections of this report provide greater detail regarding the SISC study framework, model inputs, simulation methodology, and study results.

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[3] In the 2018 Study these were referred to as LOLE FLEX events. Recognizing that these events do not correspond to load shed, they are now referred to as flexibility excursions.

[4] Unit constraints typically result in having excess reserves overnight.

I. Study Framework

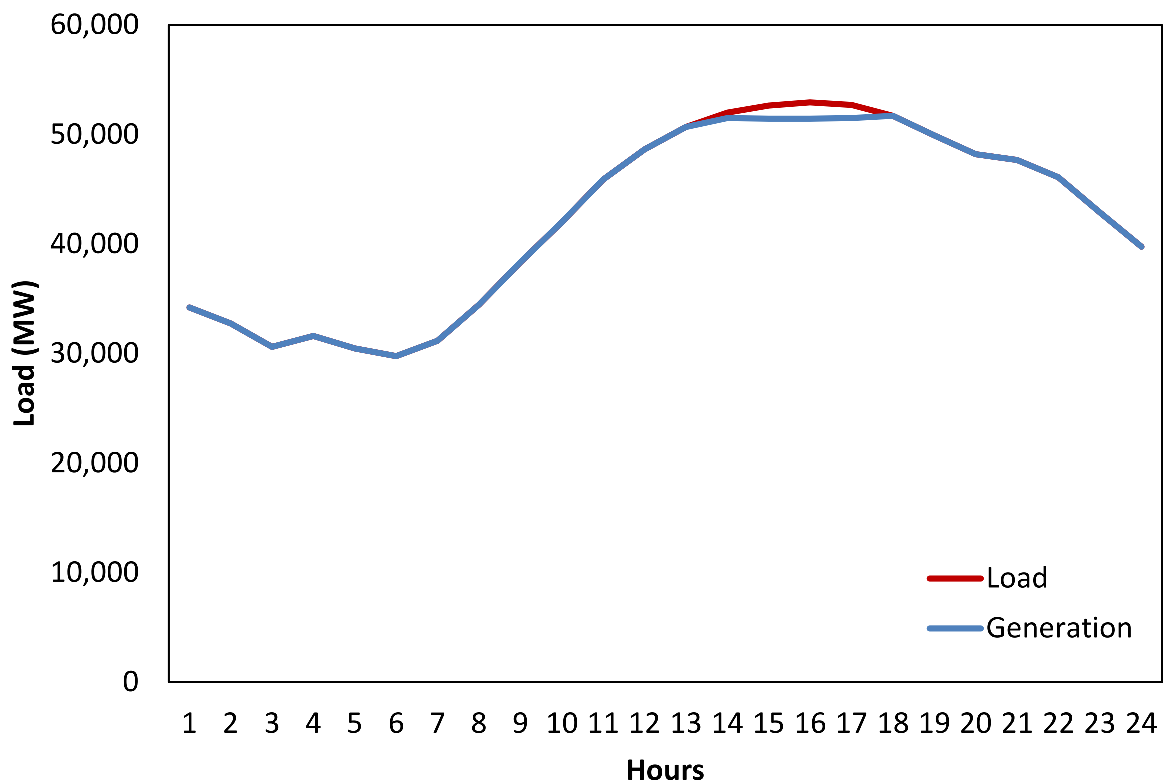
The economic effects of adding significant solar generation to a fleet are generally analyzed in a production cost simulation model. These models perform a commitment and dispatch of the conventional fleet against the gross load minus the expected renewable generation. Comparing the economic results from simulations with significant solar against simulations with more conventional resources allows planners to assess the economic implications of these additions. However, these analyses typically commit and dispatch resources with an exact representation of the load and solar patterns. This perfect knowledge aspect of the simulations overstates the value of resources like solar because they have significant inherent uncertainty. This Study incorporates the inherent uncertainty and forces the production cost model to make decisions without perfect knowledge of the load, solar, or conventional generator availability. In this framework, the objective function of the commitment and dispatch is still to minimize cost.

The enforcement of reliability requirements in simulation tools with perfect foresight is generally through a reserve margin constraint; each year is required to have adequate capacity to meet a particular reserve margin requirement. These types of simulations are unlikely to recognize reliability events partly because of their perfect foresight framework, but also because they use simplified generator outage logic. The outages at any discrete hour in the simulations typically represent average outages. In actual practice, reliability events are driven by coincident generator outages much larger in magnitude than the average. In the simulations performed for this Study, the SERVM model incorporates both load and solar uncertainty, as well as generator outage variability. In this framework, testing the capability of the conventional fleet to integrate solar resources is more reflective of actual conditions.

The inability to match generation and net load driven by solar output variability and volatility is different from capacity shortfall events analyzed in a typical resource adequacy analysis. They are events that could have been addressed by operating the existing conventional fleet differently. If solar output in a hypothetical system were to drop unexpectedly by 1,000 MW in a 5-minute period, only resources that are online or synched to the grid with the appropriate operating flexibility would be able to help alleviate the loss of the solar energy. So, for this analysis, the model differentiates events by their cause. Inputs are optimized such that events driven by a lack of capacity and events driven by a lack of flexibility achieve specific targets at minimum cost.

(1) Loss of Load Expectation (LOLE): number of days per year with loss of load due to capacity shortages. Figure 1 shows an example of a capacity shortfall which typically occurs across the peak of a day.

Figure 1. LOLE Example



(2) Flexibility Excursions: number of days per year the system cannot meet a known 5-minute net load ramp due to system flexibility shortfalls. In other words, there was enough capacity installed but not

enough flexibility to meet the net load ramps, or startup times prevented a unit from coming online fast enough to meet the unanticipated ramps. The vast majority of the flexibility excursions occur in less than one hour.

Reliability targets for capacity shortfalls have been defined by the industry for decades. The most common standard is “one day in 10 years” LOLE, or 0.1 LOLE. To meet this standard, plans must be in place to have adequate capacity such that firm load is expected to be shed one or fewer times in a 10-year period. Reliability targets for operational reliability are covered by the North American Electric Reliability Corporation (NERC) Balancing Standards. The Control Performance Standards (CPS) dictate the responsibilities for Balancing Areas (BA) to maintain frequency targets by matching generation and load.

Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and the Balancing Authority Area Control Error Limit (BAAL) would be ideal. However, simulating violations of these standards is not possible. While the simulations performed in SERVM do not measure the NERC Balancing Standards, the flexibility excursions (times when a 5-minute known net load could not be met by the system’s generation fleet) are correlated with the ability to balance load and generation. In SERVM, instead of replicating the second-to-second Area Control Error (ACE) deviations, net load and generation are balanced every 5 minutes. The committed resources are dispatched every 5 minutes to meet the unexpected movement in net load. In other words, the net load with uncertainty is frozen every 5 minutes and generators are tested to see if they are able to meet both load and minimum ancillary service requirements. Any periods in which generation is not able to meet load but there is sufficient installed capacity on the system are recorded as flexibility excursions. While there are operational reliability standards provided by NERC that provide some guidance in planning for flexibility needs, there is not a standard for flexibility excursions as measured by SERVM or in other solar integration modeling practices. Absent a standard, this Study assumes that maintaining the same level of flexibility excursions as solar penetration increases is an appropriate objective. The DEC and DEP systems were simulated with current loads and resources until operating reserves in the no solar case were similar to historical operating reserves. Running the system like this produces a number of flexibility excursions which would become the target that would be maintained after solar is added.

For each renewable penetration level analyzed, changes were made to the level of load following targeted to maintain the same number of flexibility excursions per year as seen in the base case with no solar. With more ramping capability provided by the increase in load following reserves, the unexpected drops in solar output are not as likely to create flexibility excursions. However, this creates a change in operating cost that has an impact on system costs. Comparing the total production costs assuming the same ancillary services targets used before the solar was added to the final, mitigated case production costs calculated using higher load following targets, which brings flexibility excursions back to the no solar case, determines the SISC on the system.

The more solar resources that are added, the more challenging and more expensive it becomes to carry the necessary additional ancillary services. In some hours, all conventional generation resources are dispatched near their minimum generation level in order to provide the targeted operating reserves, and yet the total generation is still above the load. This situation results in solar curtailment. The model assumes that any overgeneration can be used as load following and since incremental overgeneration is correlated with incremental solar penetration, higher curtailment is actually associated with lower SISC in this Study. Given existing solar contracts, this treatment is potentially optimistic in that curtailment may not be able to be used as flexibly as typical load following capability, and the real world system may be committed and dispatched less optimally to avoid some curtailment that is shown in the model results.

II. Model Inputs and Setup

The following sections include a discussion on the major modeling inputs included in the SISC Study. The majority of inputs are consistent with 2020 Resource Adequacy Studies completed for DEC and DEP. The model was simulated on 5-minute time intervals versus hourly intervals to capture the flexibility requirements of the system given imperfect knowledge around load, solar, and generating units. Simulating at 5-minute intervals requires additional information on generating resources and volatility distributions on load and solar as discussed in the following sections.

The utilities are modeled as islands for the SISC Study because each balancing area is responsible for its own NERC Compliance. However, given the joint dispatch agreements in place, the TRC requested a sensitivity that was performed to understand the benefits of dispatching DEC and DEP as combined systems, which is discussed later in the results. For resource adequacy, neighbor assistance capacity plays a significant role in the results. Weather diversity and generator outage diversity are benefits available to DEC and DEP regardless of the type of capacity neighboring regions build. Also, it is required to capture this assistance to achieve the one day in ten-year standard which equates to an LOLE of 0.1 events per year as outlined in the 2020 Resource Adequacy Studies. To achieve approximately 0.1 LOLE in this study, additional resources at costs above a gas CT were included in both DEC and DEP systems to mimic outside purchases.

A. Load Forecasts and Load Shapes

Load Forecasts and Shape Modeling

Table 1 displays the modeled seasonal peak forecast net of energy efficiency programs and behind the meter solar for 2024 for both DEC and DEP.

Table 1. 2024 Peak Load Forecast

	DEC	DEP East	DEP West	Coincident DEP
2020 Summer	18,456 MW	12,227 MW	879 MW	13,042 MW
2020 Winter	17,976 MW	13,390 MW	1,175 MW	14,431 MW

To model the effects of weather uncertainty, thirty-nine historical weather years (1980 - 2018) were developed to reflect the impact of weather on load. Based on the last five years of historical weather and load[5], a neural network program was used to develop relationships between weather observations and load. The historical weather consisted of hourly temperatures from five weather stations across the DEP service territory. The weather stations included Raleigh, NC, Wilmington, NC, Fayetteville, NC, Asheville, NC, and Columbia, SC. Other inputs into the neural net model consisted of hour of week, eight hour rolling average temperatures, twenty-four hour rolling average temperatures, and forty-eight hour rolling average temperatures. Different weather to load relationships were built for the summer, winter, and shoulder seasons. These relationships were then applied to the last thirty-nine years of weather to develop thirty-nine synthetic load shapes for 2024. Equal probabilities were given to each of the thirty-nine load shapes in the simulation. The synthetic load shapes were scaled to align the normal summer and winter peaks to the Companies' projected thirty-year weather normal load forecast for 2024.

[5] The historical load included January 2014 through September 2019.

Figures 2 to 5 below show the results of the weather load modeling by displaying the peak load variance for both the summer and winter seasons for each of the Companies. The y-axis represents the percentage deviation from the average peak. Thus, the bars represent the variance in projected peak loads for 2024 based on weather experienced during the historic weather years. The highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation as the winter. Based on the neural net modeling, the figures show that DEC and DEP summer peak loads can be 6-7% higher than the forecast due to weather alone, while winter peak can be about 18% higher than the forecast for DEC and more than 21% higher than the forecast for DEP in an extreme year.

Figure 2. DEC Winter Peak Weather Variability

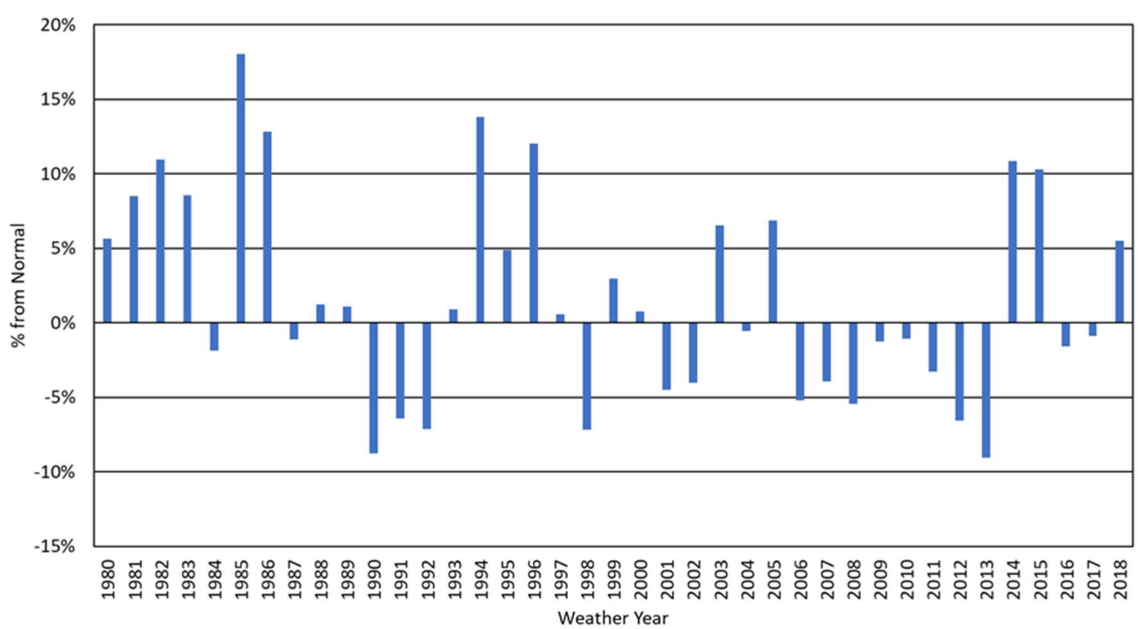


Figure 3. DEP Winter Peak Weather Variability

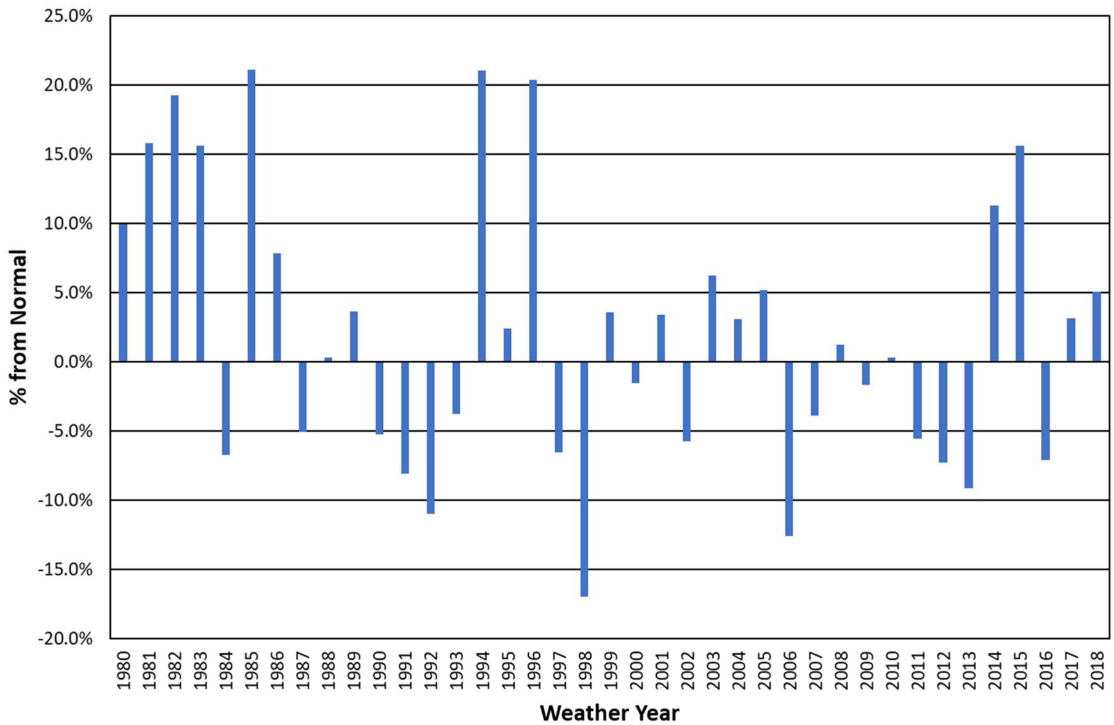


Figure 4. DEC Summer Peak Weather Variability

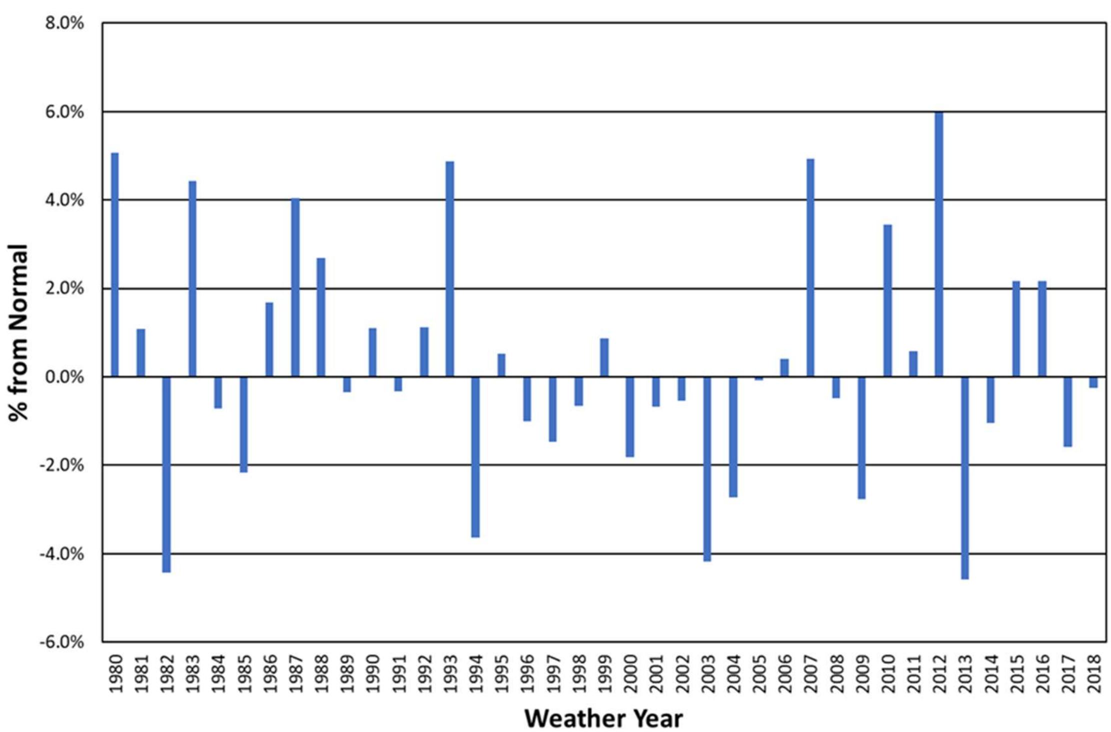
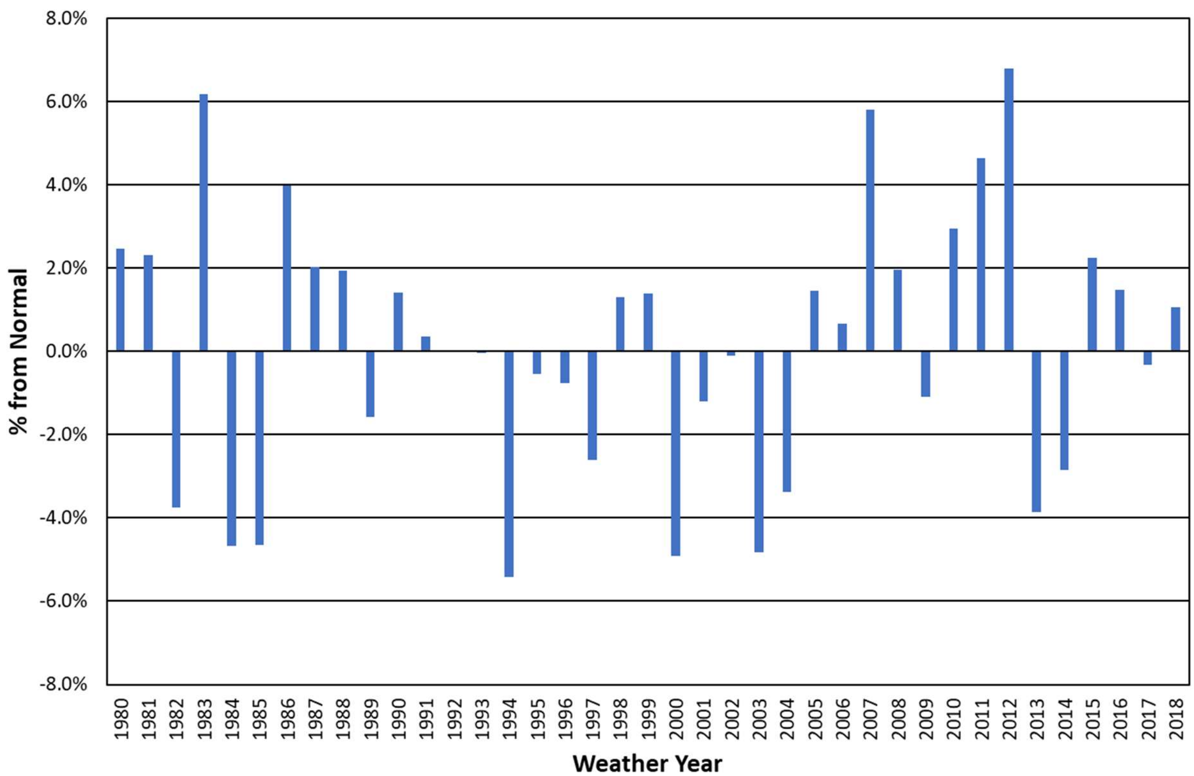


Figure 5. DEP Summer Peak Weather Variability



Economic Load Forecast Error

The same economic load forecast error multipliers used in the 2020 Resource Adequacy were used for this study. Because these assumptions are included in the base case and the change case, they have minimal impact on the results of the SISC Study. The economic load forecast error multipliers were developed to isolate the economic uncertainty that the Companies have in their four-year ahead load forecasts. Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. To estimate the economic load forecast error, the difference between Congressional Budget Office (CBO) Gross Domestic Product (GDP) forecasts four years ahead and actual data was fit to a distribution which weighted over-forecasting more heavily than under-forecasting load. Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 2 shows the economic load forecast multipliers and associated probabilities. As an illustration, 25% of the time, it is expected that load will be over-forecasted by 2.7% four years out. Within the simulations, when DEP over-forecasts load, the external regions also over-forecast load. The SERVM model utilized each of the thirty-nine weather years and applied each of these five load forecast error points to create 195 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 2. Load Forecast Error

Load Forecast Error Multipliers	Probability (%)
0.958	10.0%
0.973	25.0%
1.00	40.0%
1.02	15.0%
1.031	10.0%

B. Solar Shape Modeling

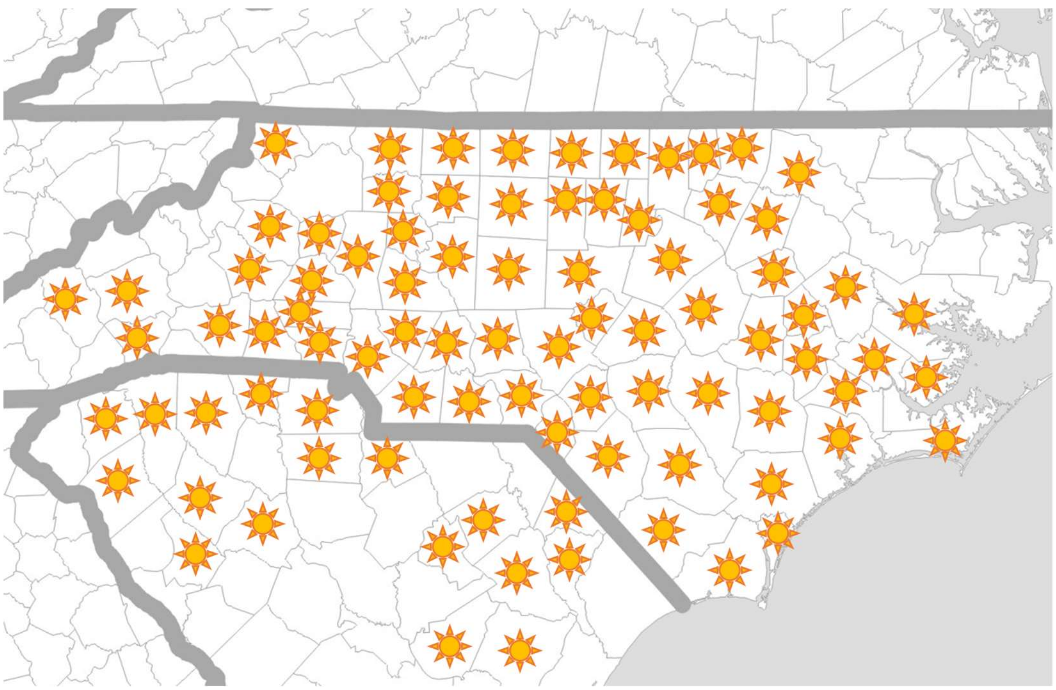
Table 3 shows the solar capacity levels that were analyzed. The solar penetration scenarios included two solar tranches which represents the expected amount of solar capacity that will be seen over the next 3-5 years which is consistent with the 2024 study year. A third higher tranche was also analyzed but since it is not used for purposes of setting the SISC charge it was only included in the Appendix for informational purposes.

Table 3. Solar Capacity Penetration Levels

	DEC MW	DEP MW
Tranche 1	976	2,908
Tranche 2	2,431	4,019

Similar to load shapes, the solar units were simulated with thirty-nine solar shapes representing thirty-nine years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. Figure 6 shows the county locations that were used which is represented with a wide geographical area across both DEC and DEP balancing areas.

Figure 6. Solar Profile Locations



The differing solar tranches were developed based on the Base Case for the 2020 Resource Adequacy Study, shown in Table 4. In order to decrease up or down capacity from these total levels, the future solar category was increased or decreased to achieve specific levels. For DEC Tranche 1, all of the future solar and a portion of CPRE Tranche 1 had to be removed since only 967 MW of solar was being modeled for that scenario.

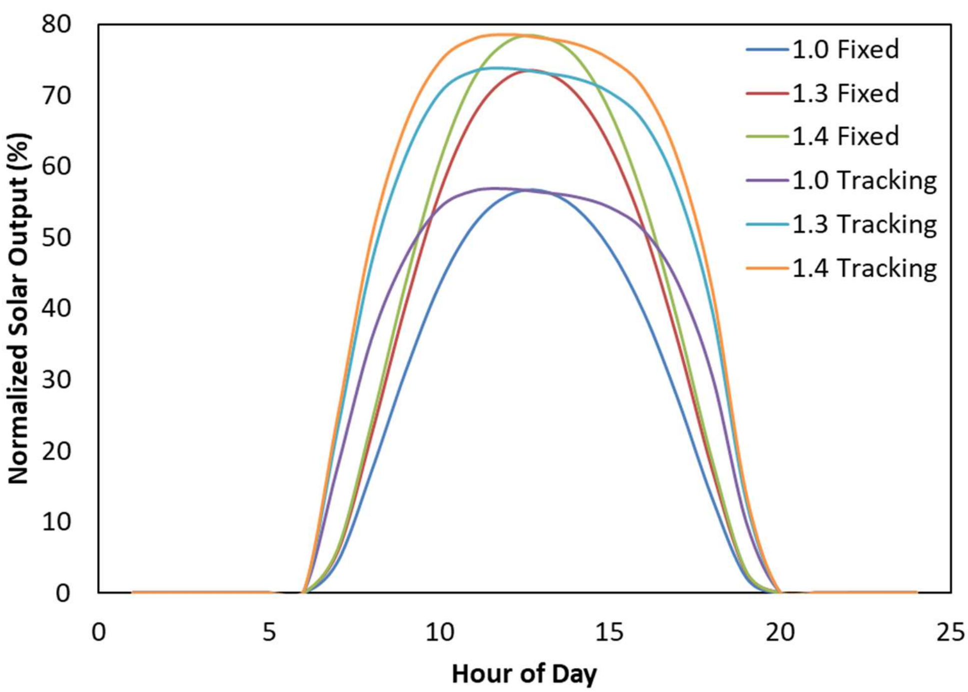
Table 4. Solar Capacity by Tranche

Unit Type	DEC Capacity (MW)	DEP Capacity (MW)
Utility Owned-Fixed	85	141
Transition-Fixed	660	2,432
CPRE Tranche 1 Fixed 40%/Tracking 60%	465	86
Future Solar Fixed 40%/Tracking 60%	1,368	1,448
Total	**2,578**	**4,107**

*Utility owned-fixed and future has a 1.4 inverter loading ratio; Transition and CPRE assumed a 1.3 inverter loading ratio

Figure 7 shows August average profiles for different inverter loading ratios for both fixed and tracking technologies. While the hourly shapes are important, it is the intra hour volatility that is discussed in the next section that drives the SISC.

Figure 7. Average August Output for Different Inverter Loading Ratios



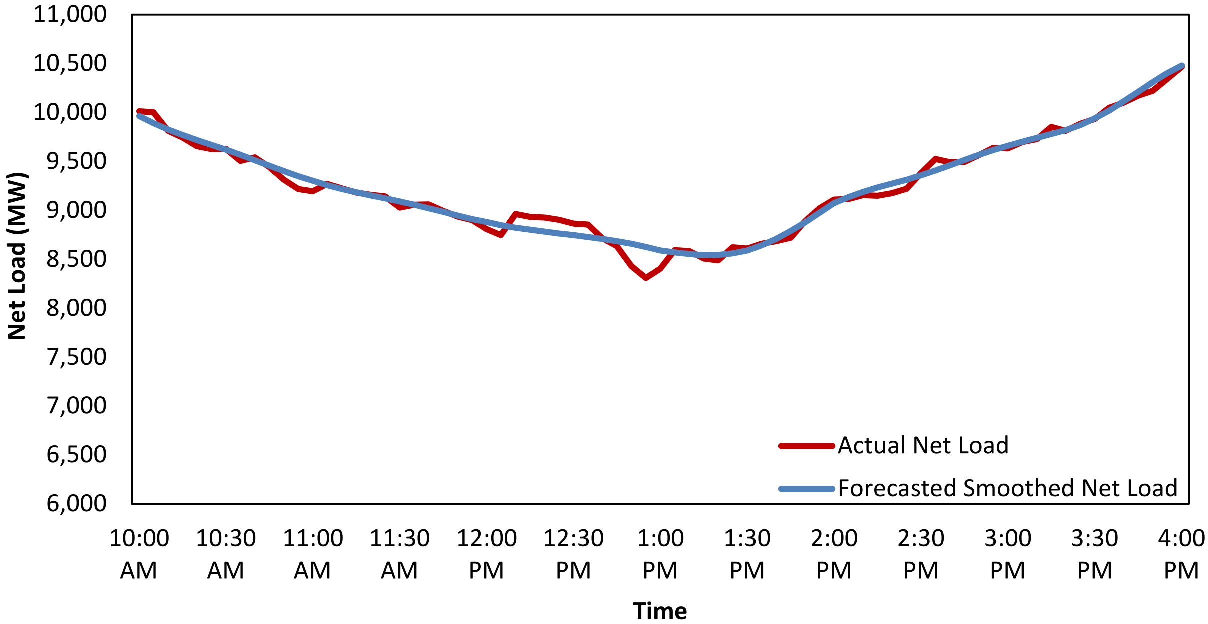
C. Load and Solar Volatility

For purposes of understanding the economic and reliability impacts of net load uncertainty, SERVM captures the implications of unpredictable intra-hour volatility. To develop data to be used in the SERVM simulations, Astrapé used 1 year of historical five-minute data for load and solar. Within the simulations, SERVM commits to the expected net load and then has to react to intra hour volatility as seen in history which may include ramping units suddenly or starting quick start units.

Intra-Hour Forecast Error and Volatility

Within each hour, load and solar can move unexpectedly due to both natural variation and forecast error. SERVM attempts to replicate this uncertainty, and the conventional resources must be dispatched to meet the changing net load patterns. SERVM replicates this by taking the smooth hour to hour load and solar profiles and developing volatility around them based on historical volatility. An example of the volatile net load pattern compared to a smooth intra-hour ramp is shown in Figure 8. The model commits to the smooth blue line over this 6-hour period but is forced to meet the red line on a 5-minute basis with the units already online or with units that have quick start capability. As intermittent resources increase, the volatility around the smooth, expected blue line increases requiring the system to be more flexible on a minute-to-minute basis. The solution to resolve the system's inability to meet load on a minute-to-minute basis is to increase operating reserves or add more flexibility to the system which both result in additional costs.

Figure 8. Volatile Net Load vs. Smoothed Net Load



The load volatility is shown in Table 5 below and is the same volatility used in the previous SISC Study performed in 2018. The 5-minute variability in load is quite low ranging mostly between +/-1% on a normalized basis. The load volatility is included in the base case and the change cases. With no intermittent resources on the system, this is the net load volatility assumed in the modeling.

Table 5. Load Volatility

Normalized Divergence (%)	Probability (%)
-2.2	0.000
-2	0.007
-1.8	0.007
-1.6	0.007
-1.4	0.016
-1.2	0.058
-1	0.205
-0.8	0.624
-0.6	1.578
-0.4	6.886
-0.2	42.055
0	39.243
0.2	6.500
0.4	1.590
0.6	0.591
0.8	0.361
1	0.170
1.2	0.066
1.4	0.009
1.6	0.003
1.8	0.001
2	0.024
2.2	0.000

The intra hour volatility of solar is higher than intra hour load volatility and is based on data from June 2019 through October 2020. The 5-minute data was analyzed and days with anomalies or missing recordings were removed from the dataset. For this reason, the dataset range was longer than one year. The historical data was aggregated at the DEC level and the DEP level. The historical DEC data represented 586 MW of existing solar capacity and the DEP level represented approximately 2,495 MW of existing solar capacity. Knowing that solar capacity is only going to increase in both service territories, it is difficult to predict the volatility of future portfolios. In both DEC and DEP, the majority of the historical data is made up of smaller-sized units while new solar resources are expected to be larger. So, while it is expected there will be additional diversity among the solar fleet, the fact that larger units are coming on may dampen the diversity benefit. Based on feedback from stakeholders and the TRC, the raw historical data volatility was utilized and then extrapolated out based on the diversity benefit trend seen in the historical data. Three levels were developed from the historical data including the 586 MW from the DEC historical data, 2,495 MW from the DEP historical data, and 2,900 MW from the combined dataset. The volatility declines with additional solar, and this dataset was trended out to 5,500 MW of solar as shown in Figure 9. The figure measures the 95TH percentile of the 5-minute solar deviation as a percentage of nameplate capacity. This measure declines as solar penetration increases.

Figure 9. Declining Volatility as a Function of Solar Capacity

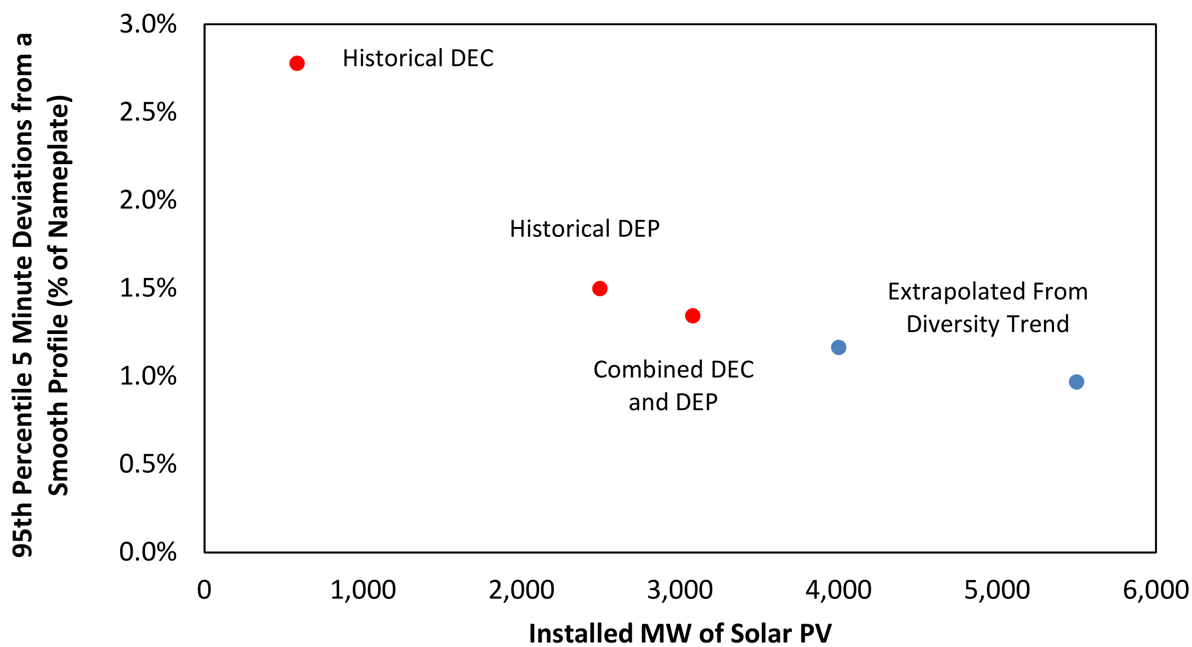


Table 5 shows the probability at different 5-minute divergence levels across the 5 solar penetrations in the previous Figure. The table shows a steady decline in unitized volatility due to diversity benefits of larger portfolios.

Table 5. DEC Base Solar Volatility - 500 MW

Solar Capacity Level MW	586	2,495	3,081	4,000	5,500
5 Minute Normalized Divergence	Probability %	Probability %	Probability %	Probability %	Probability %
-14%	0.00%	0.00%	0.00%	0.00%	0.00%
-13%	0.01%	0.00%	0.00%	0.00%	0.00%
-12%	0.01%	0.00%	0.00%	0.00%	0.00%
-11%	0.03%	0.00%	0.00%	0.00%	0.00%
-10%	0.05%	0.00%	0.00%	0.00%	0.00%
-9%	0.10%	0.00%	0.00%	0.00%	0.00%
-8%	0.19%	0.01%	0.00%	0.00%	0.00%
-7%	0.32%	0.02%	0.01%	0.00%	0.00%
-6%	0.59%	0.06%	0.03%	0.01%	0.00%
-5%	1.09%	0.21%	0.12%	0.05%	0.02%
-4%	1.91%	0.65%	0.46%	0.29%	0.11%
-3%	3.43%	1.90%	1.58%	1.14%	0.72%
-2%	6.31%	5.53%	5.24%	4.69%	3.81%
-1%	14.07%	19.74%	20.66%	21.92%	23.45%
0%	57.78%	63.39%	64.39%	65.60%	67.18%
1%	6.28%	5.76%	5.42%	4.88%	3.96%
2%	3.51%	1.91%	1.52%	1.12%	0.63%
3%	2.04%	0.58%	0.41%	0.23%	0.10%
4%	1.06%	0.18%	0.11%	0.05%	0.01%
5%	0.59%	0.05%	0.02%	0.01%	0.00%
6%	0.31%	0.02%	0.01%	0.00%	0.00%
7%	0.14%	0.00%	0.00%	0.00%	0.00%
8%	0.09%	0.00%	0.00%	0.00%	0.00%
9%	0.04%	0.00%	0.00%	0.00%	0.00%
10%	0.02%	0.00%	0.00%	0.00%	0.00%
11%	0.01%	0.00%	0.00%	0.00%	0.00%
12%	0.01%	0.00%	0.00%	0.00%	0.00%
13%	0.00%	0.00%	0.00%	0.00%	0.00%
14%	0.00%	0.00%	0.00%	0.00%	0.00%

D. Conventional Thermal Resources

Conventional thermal resources owned by the Companies and purchased as Purchase Power Agreements were modeled consistent with the 2024 study year. These resources are economically committed and dispatched to load on a 5-minute basis. Similar to the resource adequacy study, the capacities of the units are defined as a function of temperature in the simulations allowing for higher capacities in the winter compared to the summer. SERVM dispatches resources on a 5-minute basis respecting all unit constraints including startup times, ramp rates, minimum up times, minimum down times, and shutdown times. All thermal resources are allowed to serve regulation, spinning, and load following reserves as long as the minimum capacity level is less than the maximum capacity.

The unit outage data for the thermal fleet in both Companies was based on historical Generating Availability Data System (GADS) data and is consistent with the 2020 Resource Adequacy Study. Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar units. The events are entered using the following variables:

<u>Full Outage Modeling</u>
Time-to-Repair Hours
Time-to-Fail Hours

<u>Partial Outage Modeling</u>
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

<u>Maintenance Outages</u>
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

<u>Planned Outages</u>
The actual schedule for 2019 was used.

To illustrate the outage logic, assume that the historical GADS data reported that a generator had 15 full outage events and 30 partial outage events. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data and their respective inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons based on history which contain Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture. Planned maintenance events are modeled separately and dates are entered in the model representing a typical year.

E. Hydro, Pump Storage Modeling, and Battery Modeling

The hydro portfolios in DEC and DEP are modeled in segments that include Run of River (ROR) and Scheduled (Peak Shaving). The Run of River segment is dispatched as base load capacity providing its designated capacity every hour of the year. The scheduled hydro is used for shaving the daily net peak load but also includes minimum flow requirements. By modeling the hydro resources in these two segments, the model captures the appropriate amount of capacity dispatched during peak periods and is consistent with the 2020 Resource Adequacy Study.

In addition to conventional hydro, DEC owns and operates a pump-storage fleet. The total capacity included was 2,460 MW. (1) Bad Creek at a 1,680 MW summer/winter rating and (2) Jocassee at a 780 MW summer/winter rating. These resources are modeled with reservoir capacity, pumping efficiency, pumping capacity, generating capacity, and forced outage rates. SERVM uses excess capacity to economically fill up the reservoirs to ensure the generating capacity is available during peak conditions. While the pumped-storage units have fast ramping capability, the range from minimum to maximum for generating is fairly low providing minimal intra hour load following benefit for solar integration. The resources offer single speed pumping which doesn't allow for ramping capability during pumping. The pump storage fleet does assist in hourly energy balances which reduces curtailment significantly for DEC. Table 6 provides the characteristics of the pump-storage fleet.

Table 6. Pump Storage Resources

DEC Pump Storage Unit	Gen Capacity (MW)	Gen Capacity Min (MW)	Pumping Capacity (MW)	Pumping Min Capacity (MW)	Pond Capacity (MWh)	Equivalent Storage Hours (Hours)	Ramp Rate (MW/min)
Bad Creek_1	420	320	369	369	8,257	15	40
Bad Creek_2	420	320	369	369	8,257	15	40
Bad Creek_3	420	320	369	369	8,257	15	40
Bad Creek_4	420	320	369	369	8,257	15	40
Jocassee_1	195	170	205	205	14,385	27	40
Jocassee_2	195	170	205	205	14,385	27	40
Jocassee_3	195	170	205	205	14,385	27	40
Jocassee_4	195	170	205	205	14,385	27	40

The SISC Study maintained the same level of standalone battery for both DEC and DEP that was projected in the 2020 Resource Adequacy Study for DEC and DEP for the study year 2024. This results in 100 MW of standalone battery capacity in DEC and 81 MW in DEP. The batteries are allowed to be used for economic arbitrage and serve ancillary services to avoid flexibility based on their state of charge and output capability. There were no constraints modeled on the battery flexibility or number of cycles.

F. Demand Response Modeling

Demand Response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints consistent with the 2020 Resource Adequacy Study. For 2024, DEC assumed 1,122 MW of Demand Response in the summer and 442 MW in the winter. DEP assumed 1,001 MW of summer capacity and 461 MW of winter capacity.

G. Study Topology

As discussed previously, the Companies were modeled as islands for this analysis because each balancing area is responsible for its own NERC requirements. By modeling in this manner, the required operating reserves and flexibility requirements are calculated for each of the Companies. The TRC also requested the analysis be performed assuming the Joint Dispatch Agreement (JDA) between DEC and DEP was utilized. Astrapé accommodated this request and in this scenario, each BA still holds its own operating reserves, but economic exchanges are allowed to reduce the costs of the additional load following requirements. The results sections show the results as an island and a combined DEC and DEP case.

H. Ancillary Services

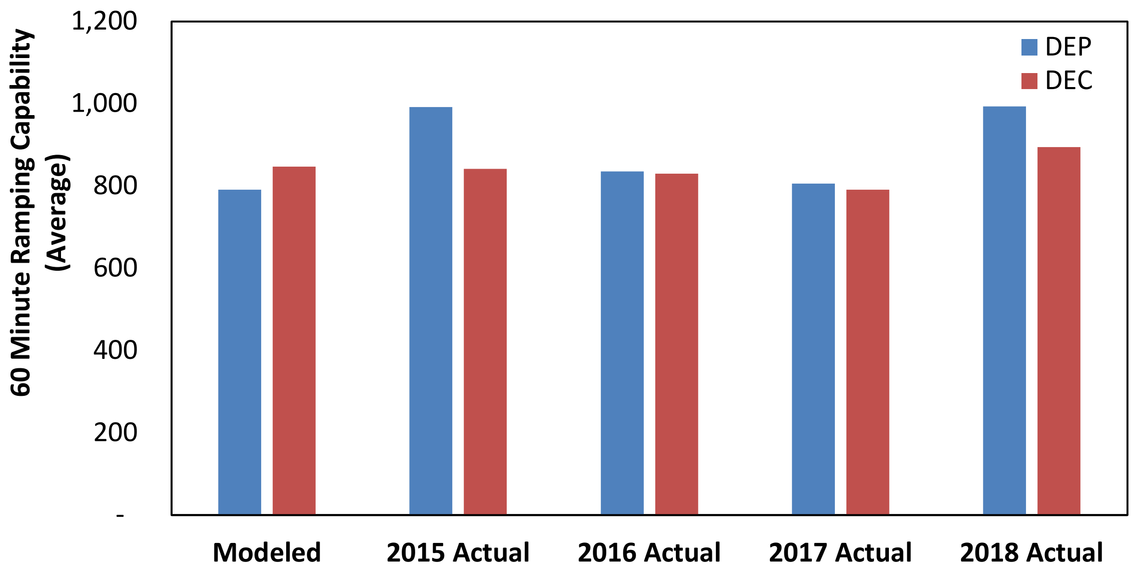
Ancillary service targets are input into SERVM. SERVM commits resources to meet energy needs plus ancillary service requirements. These ancillary services are needed for uncertain movement in net load or sudden loss of generators during the simulations. Within SERVM, these include regulation up and down, spinning reserves, load following reserves, and quick start reserves. Table 7 shows the definition of ancillary service for each study. Spinning reserves and load following up reserves are identical and represent the sum of the 10-minute ramping capability of each unit on the system. To maintain operational flexibility as solar resources are added, the load following up reserves are increased until the flexibility excursions seen in the "no solar" case are met. The load following up reserves represent an increase in ramping capability of the fleet meaning that more resources are turned on so that they can be operated further away from their maximum capacity level allowing for more ramping capability.

Table 7. Ancillary Services

Ancillary Service	Definition
Regulation Down Requirement	10 Minute Product served by units with AGC capability
Regulation Up Requirement	10 Minute Product served by units with AGC capability
Spinning Reserves Requirement	10 Min Product served by units who have minimum load less than maximum load
Load Following Down Reserves	10 Min Product served by units who have minimum load less than maximum load
Load Following Up Reserves	10 Min Product served by units who have minimum load less than maximum load
Quick Start Reserves Requirement	Served by units who are offline and have quick start capability

To ensure the operating reserves were at reasonable levels for the "no solar" case, Astrapé compared the realized 60-minute ramping capability in the model to historical dispatch data during the 2015-2018 time period. This comparison is shown in Figure 10. While this comparison would never be expected to be exact due to differences in weather, loads, resource mix, fuel prices, and generator performance among other things it does show that the modeled levels are not unreasonable as a starting point to determine flexibility excursions in the no solar scenario. Non spinning reserves are available in all cases and SERVM uses those to mitigate flexibility excursions.

Figure 10. No Solar 60 Minute Ramping Capability Comparison



I. Flexibility Excursion

A flexibility excursion is calculated by the model as any day where resources could not meet load but there was additional installed capacity on the system. These flexibility excursions are not expected to represent firm load shed events, but rather are simply a measure of the fleet's ability to follow net load changes given a particular set of operating guidelines. This is distinguished from a firm load shed event which is due to insufficient resources when operators are required to begin rolling blackouts.

III. Simulation Methodology

Since these flexibility excursions are low probability events, a large number of scenarios must be considered to accurately project these events. For this Study, SERVM utilized 39 years of historical weather and load shapes, 5 points of economic load growth forecast error, and 10 iterations of unit outage draws for each scenario to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 39 weather years * 5 load forecast errors * 10 unit outage iterations = 1,950 total iterations for each level of solar penetration simulated. Weather years and solar profiles were each given equal probability while the load forecast error multipliers were given their associated probabilities as reported in the input section of the report. This set of cases was simulated for each of the solar penetration levels in Table 8.

Table 8. Solar Penetration Levels

Tranche	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
No Solar	0	0	0	0
Tranche 1	967	967	2,908	2,950
Tranche 2	1,464	2,431	1,111	4,019

For each case, and ultimately each iteration, SERVM commits and dispatches resources to meet load and ancillary service requirements on a 5-minute basis. As discussed in the load and renewable uncertainty sections, SERVM does not have perfect knowledge of the load or renewable resource output as it determines its commitment. SERVM begins with a week-ahead commitment, and as the prompt hour approaches the model is allowed to make adjustments to its commitment as units fail and more certainty around net load is gained. Ultimately, SERVM forces the system to react to these uncertainties while maintaining all unit constraints such as ramp rates, startup times, and min-up and min-down times. During each iteration, flexibility excursions and total costs are calculated where:

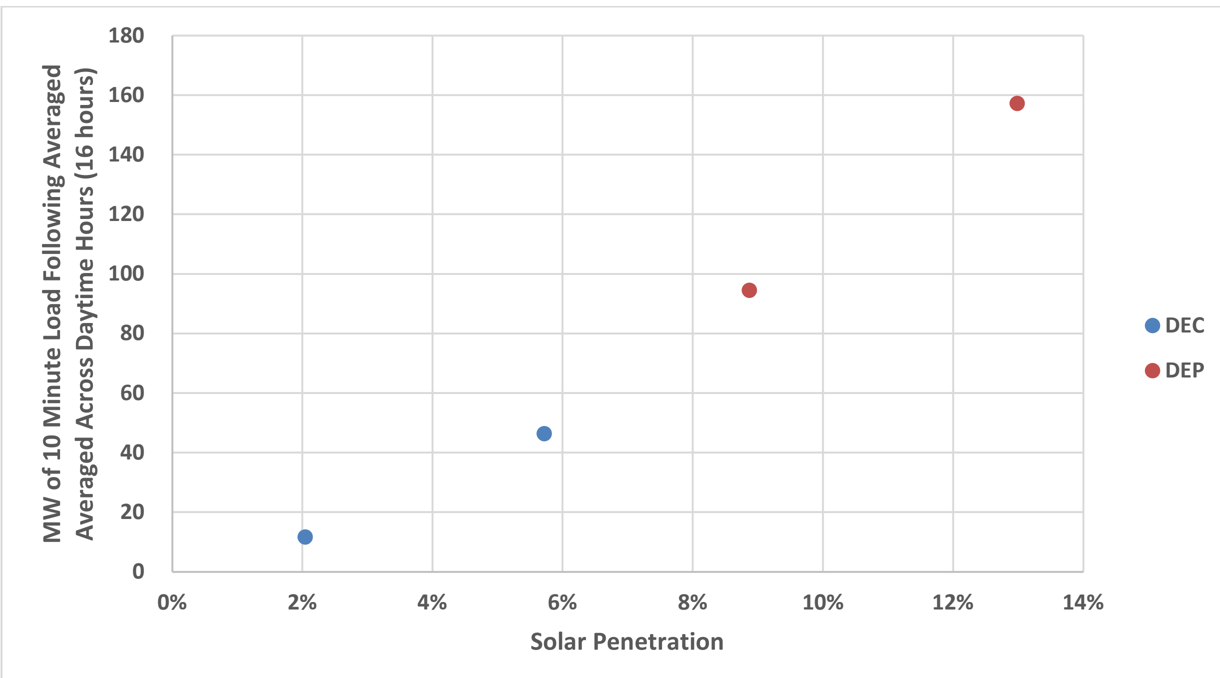
Total Costs = Fuel Costs + O&M Costs + Startup Costs

These flexibility excursions and cost components are calculated for each of the 1,950 iterations and weighted based on probability to calculate an expected total cost for each study simulated. As the systems are simulated from 0 MW of solar to several thousand MWs of solar, the net load volatility increases causing flexibility excursions to increase. In order to reduce these events down to the level that was seen in the no solar case, additional ancillary services (load following up reserves) are simulated in the model so the system can handle the larger net load volatilities. Renewable curtailment is also captured in the model, and it is noted that curtailment is used as load following in the model. If renewable curtailment was avoided with some type of curtailment penalty in the solar cases before and after load following additions, the load following costs would actually rise because the model fully uses curtailment as load following. The model also uses quick start resources in all scenarios modeled.

IV. Load Following Requirements

In response to stakeholders and the TRC, the Study added load following across the day to manage the solar ramps and volatility and targeted additions based on when the flexibility excursions were occurring. Figure 11 shows the quantified required increase in operating reserves for Tranche 1 and 2 for both DEC and DEP as a percentage of solar penetration. The additions are correlated to solar penetration as additional solar increases the load following reserves requirement.

Figure 11. Quantified Required Increase in Operating Reserves as a Percentage of Solar Penetration



Figures 12-14 show heat maps of the flexibility excursions on a 12x24 basis for the DEC no solar case, DEC Tranche 1, and DEC Tranche 2 cases. In the no solar case, any flexibility excursions are during high load periods when operating reserves have a tendency to be lower.

Figure 12. DEC No Solar Case: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.09%	0.02%	0.04%	0.02%	0.00%	0.00%	0.06%	0.00%	0.05%	0.03%	0.02%	0.05%
2	0.32%	0.06%	0.01%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.26%
3	0.20%	0.04%	0.01%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.06%	0.20%
4	0.22%	0.21%	0.33%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.05%	0.52%
5	0.28%	0.42%	0.08%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.05%	0.30%
6	0.84%	0.56%	0.51%	0.03%	0.00%	0.00%	0.00%	0.00%	0.01%	0.02%	0.12%	0.46%
7	3.42%	1.71%	0.94%	0.19%	0.01%	0.01%	0.01%	0.02%	0.29%	0.12%	0.35%	0.79%
8	1.29%	0.83%	0.67%	0.48%	0.02%	0.01%	0.12%	0.10%	0.05%	0.20%	0.74%	1.80%
9	0.61%	0.53%	0.40%	0.08%	0.03%	0.08%	0.13%	0.03%	0.09%	0.16%	0.32%	1.66%
10	0.40%	0.26%	0.24%	0.11%	0.14%	0.62%	0.64%	0.43%	0.10%	0.07%	0.13%	0.25%
11	0.05%	0.04%	0.38%	0.04%	0.04%	0.53%	0.60%	0.78%	0.21%	0.02%	0.25%	0.12%
12	1.09%	0.03%	0.07%	0.14%	0.02%	0.26%	0.80%	0.37%	0.08%	0.05%	0.03%	0.01%
13	0.35%	0.01%	0.08%	0.03%	0.07%	0.44%	0.33%	0.27%	0.13%	0.07%	0.11%	0.04%
14	0.00%	0.02%	0.05%	0.08%	0.19%	0.48%	2.35%	1.37%	0.22%	0.15%	0.09%	0.08%
15	0.04%	0.00%	0.18%	0.06%	0.50%	2.87%	5.55%	4.39%	0.88%	0.29%	0.23%	0.02%
16	0.17%	0.02%	0.14%	0.49%	1.04%	2.25%	3.75%	1.78%	1.54%	0.62%	0.07%	0.02%
17	0.46%	0.07%	0.11%	0.77%	1.35%	1.01%	2.14%	1.56%	1.60%	0.74%	0.13%	0.13%
18	1.12%	0.20%	0.14%	0.73%	0.56%	0.57%	0.60%	0.43%	1.13%	0.55%	0.18%	0.24%
19	0.29%	0.29%	0.30%	0.56%	0.53%	0.37%	0.57%	0.41%	0.59%	0.48%	0.28%	0.47%
20	0.49%	0.40%	0.42%	0.35%	0.18%	0.12%	0.50%	0.15%	0.13%	0.36%	0.28%	0.75%
21	0.18%	0.11%	0.19%	0.20%	0.02%	0.03%	0.10%	0.00%	0.16%	0.14%	0.14%	0.34%
22	0.05%	0.05%	0.10%	0.03%	0.00%	0.17%	0.02%	0.01%	0.03%	0.48%	0.15%	0.09%
23	0.05%	0.02%	0.05%	0.09%	0.16%	0.00%	0.06%	0.12%	0.01%	0.94%	0.01%	0.06%
24	0.01%	0.02%	0.02%	0.05%	0.02%	0.00%	0.31%	0.24%	0.14%	0.66%	0.01%	0.10%

As solar is added, the flexibility excursions move towards later in the afternoon or during solar ramp up periods as shown in Figures 13 and 14.

Figure 13. DEC Tranche 1 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.42%	0.09%	0.01%	0.01%	0.07%	0.00%	0.08%	0.07%	0.11%	0.07%	0.02%	0.16%
2	0.26%	0.13%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.03%	0.29%
3	0.08%	0.02%	0.02%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%	0.00%	0.03%	0.12%
4	0.18%	0.23%	0.13%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.06%	0.26%
5	0.53%	0.49%	0.21%	0.00%	0.12%	0.00%	0.00%	0.00%	0.00%	0.00%	0.09%	0.32%
6	1.25%	0.89%	0.90%	0.06%	0.00%	0.03%	0.00%	0.00%	0.02%	0.08%	0.20%	0.61%
7	2.50%	1.76%	0.81%	0.25%	0.04%	0.02%	0.01%	0.04%	0.00%	0.20%	0.49%	0.84%
8	1.49%	0.87%	0.57%	0.17%	0.09%	0.07%	0.10%	0.11%	0.07%	0.21%	0.77%	1.38%
9	0.65%	0.29%	0.32%	0.21%	0.04%	0.15%	0.36%	0.08%	0.05%	0.12%	0.23%	0.44%
10	0.35%	0.10%	0.19%	0.10%	0.17%	0.39%	0.53%	0.43%	0.07%	0.10%	0.08%	0.25%
11	0.07%	0.01%	0.31%	0.06%	0.16%	0.44%	0.56%	0.52%	0.21%	0.07%	0.08%	0.04%
12	0.06%	0.01%	0.11%	0.06%	0.07%	0.38%	0.89%	0.54%	0.15%	0.09%	0.10%	0.00%
13	0.03%	0.04%	0.09%	0.20%	0.25%	0.20%	0.35%	0.72%	0.27%	0.02%	0.07%	0.10%
14	0.02%	0.01%	0.11%	0.08%	0.22%	0.26%	1.79%	0.42%	0.27%	0.19%	0.14%	0.03%
15	0.08%	0.00%	0.05%	0.09%	0.27%	1.13%	2.35%	2.39%	0.25%	0.41%	0.14%	0.07%
16	0.06%	0.04%	0.11%	0.26%	0.58%	1.65%	4.41%	2.82%	0.95%	0.66%	0.41%	0.14%
17	0.74%	0.29%	0.24%	0.68%	1.27%	1.76%	3.56%	2.01%	2.35%	1.49%	0.31%	0.31%
18	0.34%	0.33%	0.39%	0.90%	1.73%	1.11%	1.18%	1.14%	1.32%	0.69%	0.24%	0.49%
19	0.40%	0.25%	0.51%	0.71%	1.16%	0.90%	0.79%	0.49%	0.90%	0.46%	0.32%	0.35%
20	1.32%	0.46%	0.47%	0.33%	0.51%	0.10%	0.15%	0.23%	0.28%	0.30%	0.35%	0.63%
21	0.48%	0.16%	0.35%	0.11%	0.09%	0.06%	0.09%	0.04%	0.02%	0.07%	0.42%	0.47%
22	0.37%	0.24%	0.12%	0.09%	0.01%	0.00%	0.03%	0.00%	0.00%	0.07%	0.07%	0.09%
23	0.07%	0.01%	0.04%	0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.02%	0.00%	0.11%
24	1.01%	0.00%	0.08%	0.04%	0.00%	0.06%	0.07%	0.15%	0.08%	0.02%	0.05%	0.02%

Figure 14. DEC Tranche 2 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.13%	0.01%	0.00%	0.02%	0.03%	0.00%	0.10%	0.03%	0.07%	0.08%	0.00%	0.04%
2	0.14%	0.02%	0.00%	0.01%	0.00%	0.00%	0.00%	0.02%	0.05%	0.01%	0.01%	0.06%
3	0.26%	0.00%	0.01%	0.11%	0.00%	0.00%	0.00%	0.00%	0.10%	0.00%	0.00%	0.03%
4	0.17%	0.10%	0.07%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.04%	0.14%
5	0.17%	0.27%	0.16%	0.06%	0.03%	0.00%	0.00%	0.01%	0.00%	0.02%	0.04%	0.26%
6	0.74%	0.74%	0.78%	0.63%	0.51%	0.03%	0.01%	0.00%	0.06%	0.49%	0.31%	0.49%
7	2.02%	1.14%	1.26%	0.41%	0.12%	0.22%	0.11%	0.13%	0.24%	0.56%	0.44%	0.59%
8	1.31%	0.51%	0.16%	0.14%	0.05%	0.05%	0.09%	0.24%	0.09%	0.05%	0.31%	0.85%
9	0.13%	0.09%	0.22%	0.05%	0.10%	0.22%	0.16%	0.25%	0.06%	0.04%	0.09%	0.10%
10	0.01%	0.06%	0.05%	0.07%	0.07%	0.17%	0.42%	0.35%	0.21%	0.10%	0.11%	0.11%
11	0.08%	0.01%	0.27%	0.07%	0.19%	0.23%	0.40%	0.52%	0.25%	0.08%	0.08%	0.05%
12	0.02%	0.02%	0.08%	0.12%	0.11%	0.35%	0.44%	0.45%	0.24%	0.09%	0.05%	0.03%
13	0.02%	0.02%	0.07%	0.09%	0.20%	0.23%	0.30%	0.39%	0.19%	0.22%	0.08%	0.01%
14	0.02%	0.00%	0.02%	0.10%	0.32%	0.29%	0.32%	0.42%	0.18%	0.17%	0.05%	0.02%
15	0.03%	0.01%	0.05%	0.28%	0.44%	0.30%	0.41%	0.94%	0.27%	0.17%	0.11%	0.06%
16	0.13%	0.01%	0.16%	0.38%	0.46%	0.43%	0.73%	0.86%	0.54%	0.45%	0.45%	0.08%
17	3.81%	0.44%	0.36%	0.82%	1.38%	1.09%	1.48%	1.78%	1.33%	4.98%	2.97%	2.06%
18	0.89%	0.65%	2.74%	4.30%	2.06%	1.68%	1.58%	2.23%	3.50%	1.33%	0.08%	0.51%
19	0.30%	0.25%	0.24%	2.04%	2.64%	2.15%	1.80%	2.13%	0.92%	0.30%	0.13%	0.28%
20	0.25%	0.16%	0.25%	0.15%	0.43%	0.41%	0.31%	0.21%	0.26%	0.17%	0.15%	0.36%
21	0.17%	0.15%	0.08%	0.07%	0.12%	0.05%	0.04%	0.06%	0.08%	0.03%	0.14%	0.23%
22	0.02%	0.04%	0.19%	0.08%	0.01%	0.01%	0.04%	0.02%	0.00%	0.03%	0.04%	0.02%
23	0.04%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.03%	0.02%
24	0.02%	0.01%	0.03%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.02%

Figures 15-16 show the load following targets input into the model to lower the amount of flexibility excursions until they are at the same level as the no solar case. While these are the targets for the commitment, the realized incremental reserves are output as reported previously in Figure 11. Because the modeling can take advantage of periods where there are excess reserves due to commitment constraints on resources, the realized additional load following will always be less than the change in targets. In other words, there are periods where the target was increased but the system is already providing ample reserves on some of those days, so the incremental realized reserves reported in the results are less than these target input changes. These targets were adjusted upward in an iterative process by analyzing when the flexibility excursions were occurring and were increased until the number of events approached the number of events in the no solar case.

Figure 15. DEC Tranche 1: Final Incremental Load Following Targets (MW)

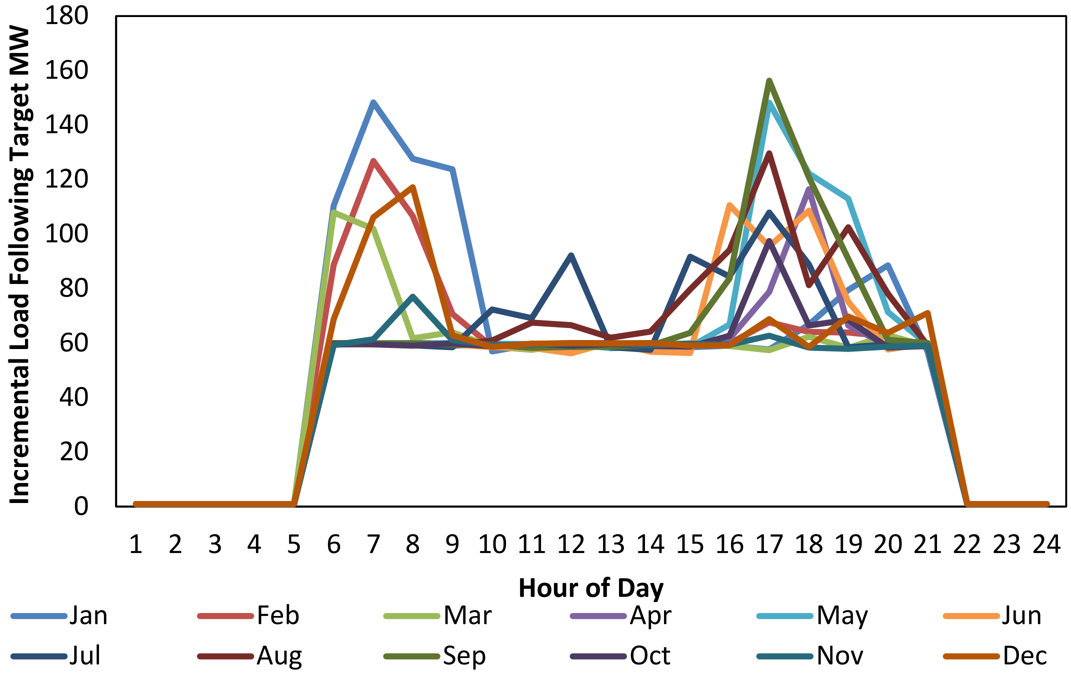
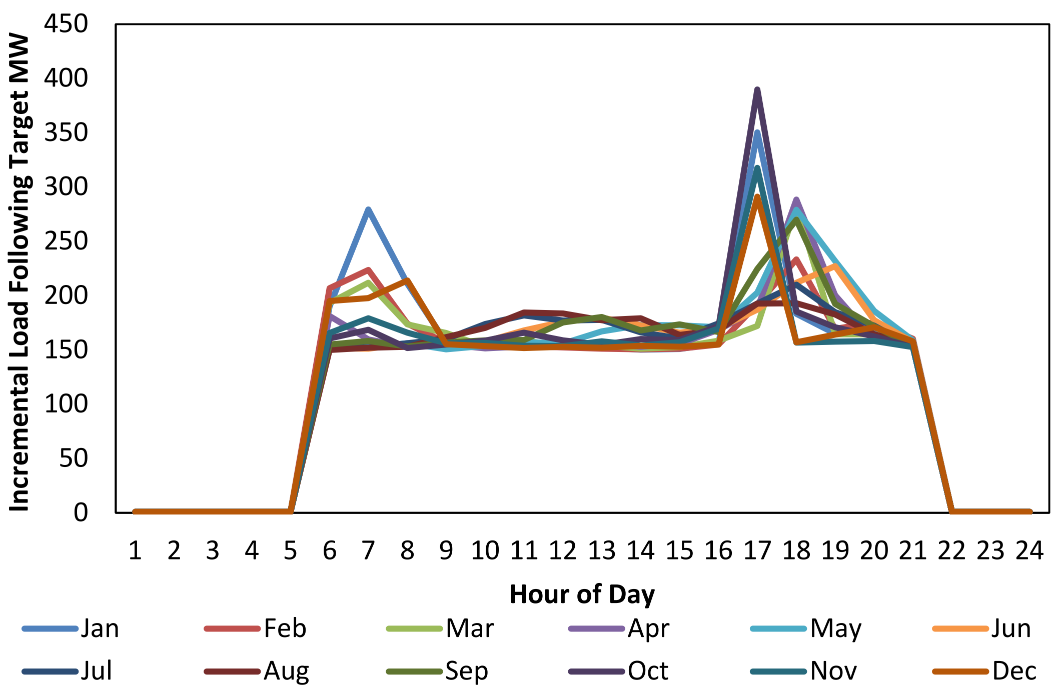


Figure 16. DEC Tranche 2: Final Incremental Load Following Targets (MW)



The same figures are shown for DEP in Figures 17-21 below.

Figure 17. DEP No Solar Case: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	0.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%
4	0.21%	0.03%	0.06%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%
5	0.11%	0.15%	0.18%	0.26%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.18%	0.75%
6	2.30%	1.92%	0.69%	0.04%	0.30%	0.00%	0.00%	0.00%	0.00%	0.12%	1.35%	1.40%
7	1.45%	3.23%	1.00%	0.37%	0.00%	0.00%	0.00%	0.00%	2.69%	0.00%	1.92%	1.99%
8	4.78%	2.98%	1.19%	0.12%	0.00%	0.00%	0.21%	0.22%	0.00%	0.10%	0.60%	1.45%
9	3.33%	0.88%	0.14%	0.00%	0.00%	0.93%	0.63%	0.11%	0.09%	0.00%	0.05%	0.14%
10	0.29%	0.07%	0.00%	0.00%	0.10%	0.14%	0.23%	0.07%	0.02%	0.01%	0.00%	0.10%
11	0.29%	0.00%	0.00%	0.00%	0.01%	0.29%	0.48%	0.28%	0.00%	0.04%	0.00%	0.00%
12	0.00%	0.00%	0.00%	0.00%	0.05%	0.11%	0.19%	0.03%	0.02%	0.00%	0.00%	0.00%
13	0.00%	0.00%	0.01%	0.00%	0.02%	0.13%	0.16%	0.21%	0.17%	0.00%	0.00%	0.00%
14	0.00%	0.00%	0.00%	0.00%	0.33%	0.29%	0.18%	0.40%	0.56%	0.16%	0.00%	0.00%
15	0.00%	0.00%	0.00%	0.47%	0.55%	1.17%	0.68%	1.72%	1.28%	0.67%	0.00%	0.00%
16	0.00%	0.00%	0.00%	0.41%	1.23%	1.09%	0.81%	1.84%	3.19%	1.33%	0.00%	0.00%
17	0.00%	0.00%	0.24%	0.97%	1.61%	1.49%	1.10%	1.52%	3.14%	0.97%	0.00%	0.00%
18	0.00%	0.00%	0.11%	0.39%	3.91%	1.09%	1.03%	1.15%	2.16%	1.16%	0.07%	0.00%
19	0.33%	0.42%	0.05%	0.21%	0.47%	0.08%	0.11%	0.37%	0.97%	0.21%	2.18%	0.07%
20	0.17%	0.71%	0.95%	3.69%	0.01%	0.00%	0.14%	0.00%	0.04%	0.07%	0.07%	0.46%
21	0.56%	0.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.06%	0.46%
22	0.01%	0.00%	0.00%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
23	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 18. DEP Tranche 1 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.09%	0.02%	0.14%	0.15%	0.05%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	0.03%
6	0.09%	0.68%	1.93%	3.32%	2.86%	0.00%	0.00%	0.00%	0.14%	0.20%	2.64%	0.32%
7	0.13%	0.14%	0.74%	0.17%	0.01%	0.01%	0.00%	0.00%	0.01%	0.82%	3.59%	0.15%
8	0.18%	0.06%	0.02%	0.01%	0.00%	0.00%	0.02%	0.00%	0.00%	0.00%	0.09%	0.14%
9	0.09%	0.00%	0.02%	0.01%	0.01%	0.00%	0.01%	0.01%	0.00%	0.02%	0.03%	0.04%
10	0.00%	0.00%	0.01%	0.02%	0.00%	0.01%	0.03%	0.02%	0.00%	0.00%	0.00%	0.02%
11	0.00%	0.00%	0.01%	0.01%	0.06%	0.06%	0.05%	0.08%	0.03%	0.00%	0.01%	0.00%
12	0.00%	0.01%	0.02%	0.05%	0.02%	0.08%	0.02%	0.02%	0.05%	0.08%	0.01%	0.00%
13	0.00%	0.00%	0.02%	0.08%	0.11%	0.08%	0.03%	0.05%	0.07%	0.07%	0.00%	0.01%
14	0.01%	0.00%	0.07%	0.35%	0.54%	0.08%	0.05%	0.10%	0.12%	0.14%	0.11%	0.01%
15	0.01%	0.07%	0.26%	0.86%	0.99%	0.32%	0.12%	0.07%	0.31%	0.63%	0.84%	0.10%
16	0.18%	0.19%	0.99%	2.21%	1.81%	0.27%	0.12%	0.12%	0.68%	2.08%	6.59%	1.39%
17	0.63%	1.75%	4.08%	3.87%	3.16%	0.76%	0.59%	0.97%	1.77%	3.59%	1.63%	0.75%
18	0.01%	0.70%	2.02%	4.89%	2.98%	1.43%	1.80%	2.74%	3.43%	1.01%	0.01%	0.00%
19	0.01%	0.02%	0.00%	0.67%	4.38%	2.61%	2.35%	1.70%	0.04%	0.01%	0.01%	0.01%
20	0.03%	0.03%	0.01%	0.00%	0.01%	0.01%	0.01%	0.02%	0.00%	0.00%	0.03%	0.03%
21	0.00%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.03%
22	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
23	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 19. DEP Tranche 2 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	0.01%	0.02%	0.04%	0.14%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%	0.04%
6	0.05%	0.15%	0.77%	2.15%	1.04%	0.02%	0.00%	0.01%	0.08%	0.07%	1.38%	0.17%
7	0.05%	0.08%	0.46%	0.04%	0.00%	0.00%	0.01%	0.00%	0.00%	0.17%	1.92%	0.08%
8	0.11%	0.02%	0.02%	0.02%	0.02%	0.00%	0.00%	0.01%	0.00%	0.02%	0.11%	0.09%
9	0.01%	0.01%	0.04%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%	0.04%	0.01%
10	0.01%	0.00%	0.02%	0.03%	0.00%	0.01%	0.02%	0.04%	0.00%	0.03%	0.06%	0.05%
11	0.00%	0.00%	0.00%	0.01%	0.02%	0.06%	0.07%	0.06%	0.05%	0.02%	0.01%	0.01%
12	0.00%	0.01%	0.01%	0.02%	0.13%	0.16%	0.08%	0.13%	0.10%	0.10%	0.02%	0.01%
13	0.00%	0.00%	0.00%	0.12%	0.24%	0.26%	0.12%	0.17%	0.13%	0.04%	0.03%	0.01%
14	0.00%	0.01%	0.09%	0.18%	0.46%	0.39%	0.15%	0.24%	0.24%	0.25%	0.25%	0.01%
15	0.03%	0.01%	0.28%	0.47%	1.05%	0.52%	0.20%	0.29%	0.71%	0.67%	0.48%	0.10%
16	0.12%	0.17%	0.89%	1.28%	1.85%	0.95%	0.23%	0.43%	1.21%	1.80%	3.09%	1.88%
17	3.09%	2.43%	3.65%	2.28%	2.24%	0.63%	0.49%	0.71%	1.34%	5.34%	4.11%	1.63%
18	0.10%	1.31%	3.65%	4.70%	2.81%	1.58%	1.81%	2.63%	3.83%	1.59%	0.00%	0.00%
19	0.00%	0.02%	0.00%	2.00%	4.15%	2.54%	2.63%	3.38%	0.03%	0.00%	0.00%	0.04%
20	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%
21	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
22	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
23	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Figure 20. DEP Tranche 1: Final Incremental Load Following Targets

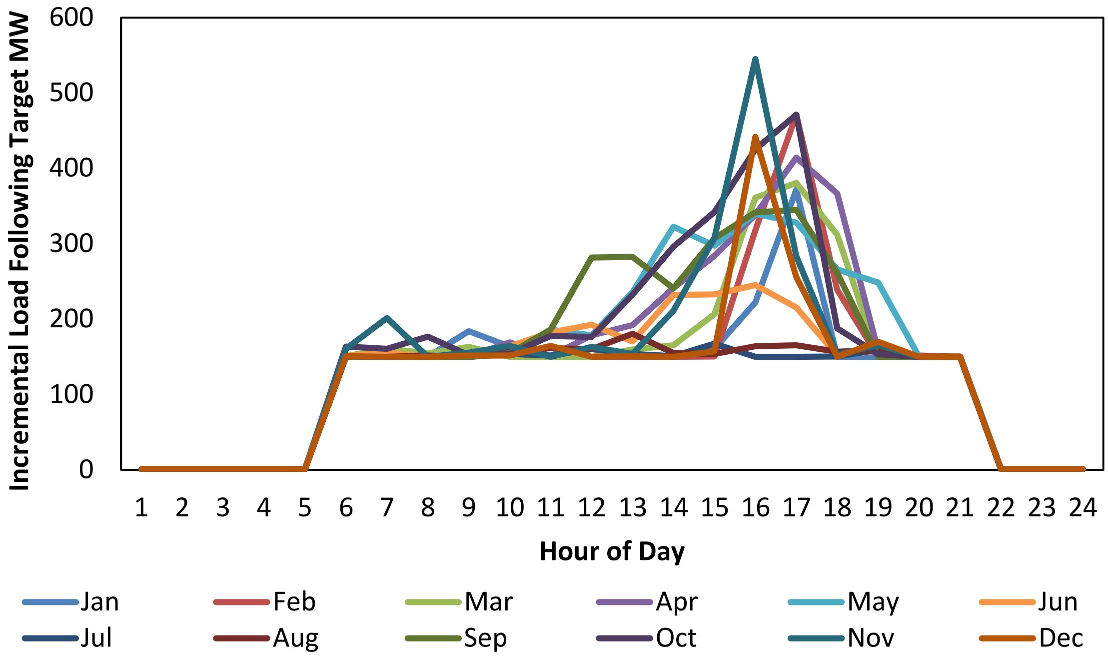
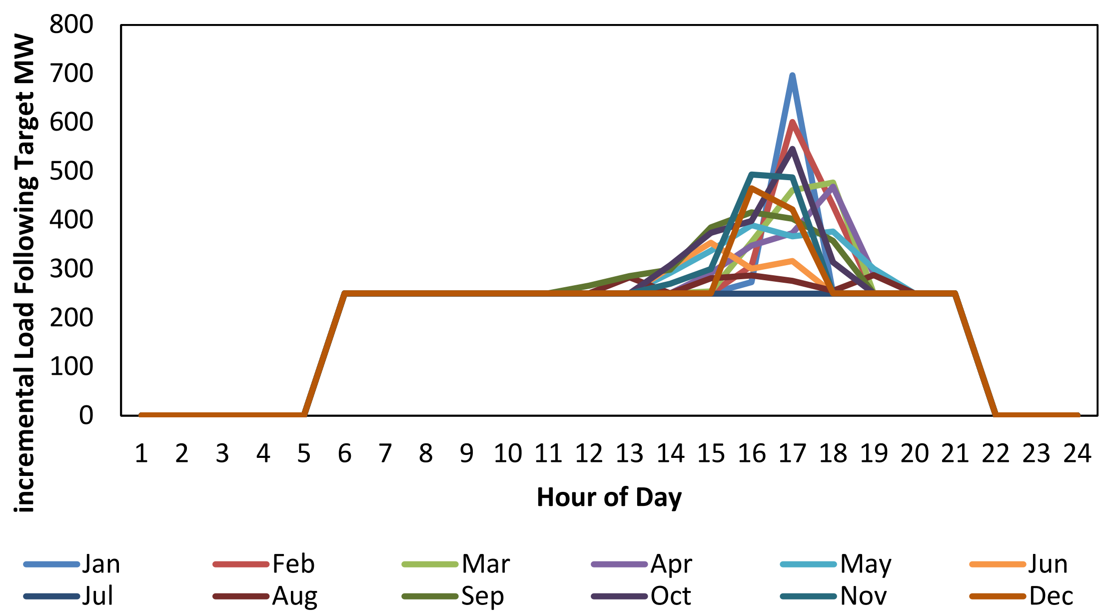


Figure 21. DEP Tranche 2: Final Incremental Load Following Targets for Commitment



IV. Island Results

Tables 9 and 10 shows the results of the island cases for both DEC and DEP. As solar generation is added, net load volatility increases causing flexibility excursions to increase if nothing is done to mitigate them. To reduce the excursions, additional load following as presented in the previous sections are added into the model. This higher load following target which causes an increase in costs. For DEC, the results show that as solar increases from 0 MW to 967 MW, 12 MW on average across daytime hours of additional load following is required to maintain the same number of excursions that occurred in the 0 MW solar scenario. The increase in load following also increases renewable curtailment slightly by 2,338 MWh. The total costs of the additional load following across the incremental 967 MW of solar generation is calculated as $1.00 /MWh. As tranche 2 is added to the analysis, which includes 2,431 MW, 46 MW of additional load following on average across daytime hours is required compared to the 0 MW solar case. The total costs of the additional load following for the incremental tranche 2 solar is $1.67/MWh while the total average cost of the additional load following for tranche 2 solar is $1.43/MWh. The incremental cost represents the cost of the solar capacity between Tranche 1 and Tranche 2. A minimal amount of additional renewable curtailment is seen in DEC largely due to the pump storage resources which assist in managing hourly imbalances. Similar patterns are seen in the DEP Table 10. Tranche 1 which assumes 2,908 MW of solar requires 95 MW of additional load following on average across daytime hours which results in $2.01/MWh. Tranche 2 which assumes 4,019 MW of solar capacity requires 157 MW of additional load following on average across daytime hours which results in a total cost of load following of $2.41/MWh. The incremental cost of Tranche 2 is $3.26/MWh. For DEP, the curtailment is higher because it does not have access to the same pump storage seen in DEC. Curtailment puts downward pressure on the SISC because it serves as free load following.

Table 9. DEC Island Results

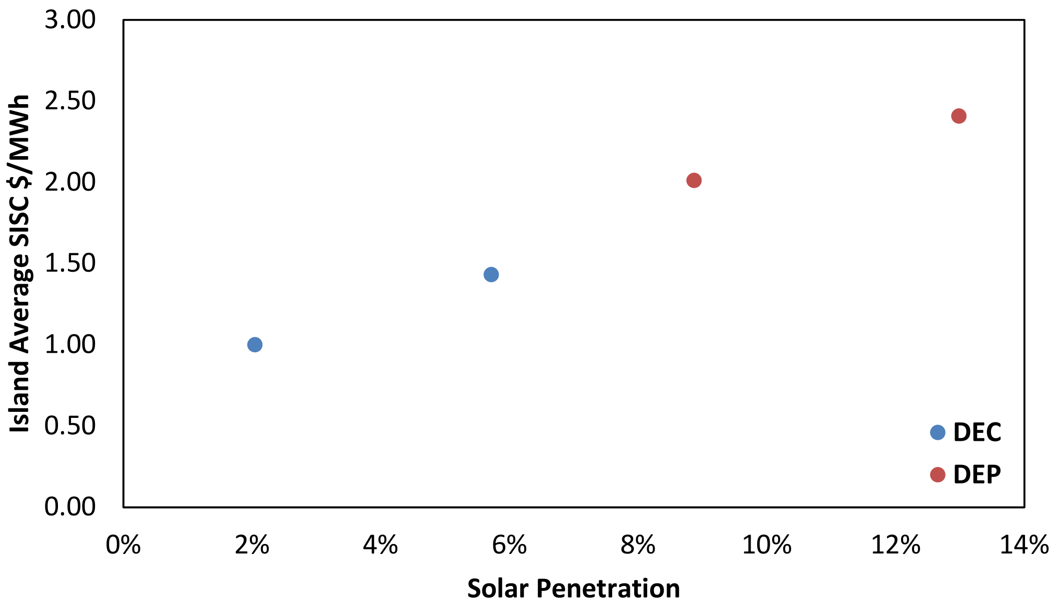
	DEC No Solar	DEC Tranche 1	DEC Tranche 2
Total Solar (MW)	0	967	2,431
Flexibility Violations (Events Per Year)	2.6	2.6	2.6
Average SISC ($/MWh)	0	1.00	1.43
Incremental SISC ($/MWh)	0	1.00	1.67
Realized 10-Minute Load Following Reserves (Average MW Over Solar Hours Assuming 16 Hours) (MW)	0	12	46
Additional Curtailment Due to Solar and Load Following (MWh)	0	2,338	43,003
Additional Curtailment Only Due to Additional Load Following (MWh)	0	227	6,882
Solar Generation (MWh)	0	1,887,495	5,279,075
Percentage of Solar Generation Curtailed (%)	0	0.12%	0.80%
Percentage of Solar Generation Curtailed Due to Additional Load Following (%)	0	0.01%	0.13%

Table 10. DEP Island Results

	DEP No Solar	DEP Tranche 1	DEP Tranche 2
Total Solar (MW)	0	2,908	4,019
Flexibility Violations (Events Per Year)	0.6	0.6	0.6
Average SISC ($/MWh)	0	2.01	2.41
Incremental SISC ($/MWh)	0	2.01	3.26
Realized 10-Minute Load Following Reserves (Average MW Over Solar Hours Assuming 16 Hours) (MW)	0	95	157
Additional Curtailment Due to Solar and Load Following (MWh)	0	392,280	1,187,332
Additional Curtailment Only Due to Additional Load Following (MWh)	0	27,072	94,271
Solar Generation (MWh)	0	5,677,218	8,312,633
Percentage of Solar Generation Curtailed (%)	0	6.8%	14.1%
Percentage of Solar Generation Curtailed Due to Additional Load Following (%)	0	0.5%	1.1%

Figure 22 shows the island average SISC as a function of solar penetration for both DEC and DEP.

Figure 22. Average SISC as a function of Solar Penetration



V. Combined (JDA Modeled) Results

The combined (JDA Modeled) results model the two DEC and DEP balancing areas with transmission capability between them. Table 11 shows the DEC to DEP E and DEC to DEP W transmission capability, which is consistent with the 2020 Resource Adequacy Study.

Table 11. Import and Export Capability

Source	Sink	Winter Capability MW	Summer Capability MW
DEC	DEP E	1,373	1,373
DEC	DEP W	341	341
DEP E	DEC	2,600	1,900
DEP W	DEC	155	155

In these simulations, the realized load following additions determined in the island case were targeted for the combined case except now economic transfers can be made on a 5-minute basis. These economic transfers reduce system costs and in turn reduce integration costs. In discussions with the Companies' operators, this method is potentially optimistic because SERVM has perfect foresight within the 5-minute time step to dispatch generation in both zones to perfectly minimize system production costs, whereas the JDA may be subject to more uncertainty and less dispatch flexibility.

The results are shown below in Table 12 for both Tranche 1 and 2. As expected, the total costs to increase the load following across the two systems decreases. For Tranche 1 the total costs decrease from 13.3 million dollars to 10.7 million dollars. This benefit is then allocated across the Companies to develop a lower SISC rate for each Company. Astrapé along with the TRC and the Companies determined it was most appropriate to allocate the benefit based on the rated cost of load following (in $/MWh) from the combined analysis. The load following cost is the total production cost increase divided by the additional

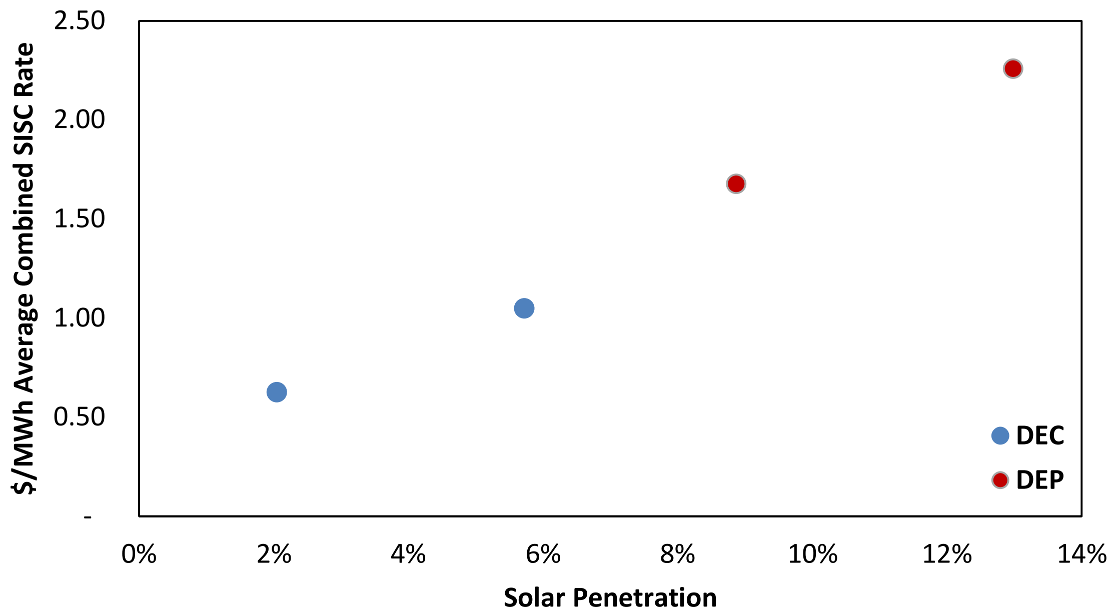
10-minute load following reserves that are increased. This results in average and incremental SISC values assuming the benefit of the JDA as expressed at the bottom of Table 12.

Table 12. Combined (JDA Modeled) Results with Load Following Cost Allocation

	DEC Tranche 1	DEP Tranche 1	Combined Tranche 1	DEC Tranche 2	DEP Tranche 2	Combined Tranche 2
Solar Capacity (MW)	967	2,908	3,875	2,431	4,019	6,450
Solar Generation (MWh)	1,887,513	5,677,206	7,564,719	5,279,071	8,312,634	13,591,705
Island 10-Minute Load Following Reserves Needed (Average Over Daily 16 Hours) (MW)	12	95	106	46	157	204
Island 10 Min Load Following Cost Rate ($/MWh)	27.45	20.67	21.42	27.85	21.79	23.17
Island Integration Costs ($)	1,886,777	11,422,833	13,309,610	7,555,552	20,015,360	27,570,912
Average Island SISC ($/MWh)	1.00	2.01	1.76	1.43	2.41	2.03
Combined (JDA Modeled) 10-Minute Load Following Cost Rate ($/MWh)	17.25	17.25	17.25	20.45	20.45	20.45
Combined (JDA Modeled) Integration Costs ($)	3,174,863	7,542,222	10,717,085	9,645,181	14,691,557	24,336,737
Average SISC with Combined (JDA Modeled) Load Following Rates ($/MWh)	0.63	1.68	1.42	1.05	2.26	1.79
Incremental SISC with Combined (JDA Modeled) Load Following Rates ($/MWh)	0.63	1.68	1.42	1.29	3.51	2.26

Figure 23 shows the average SISC for both tranches for the Combined Cases as a function of solar penetration.

Figure 23. Average Combined SISC Rates for Tranche 1 and 2



Lastly Table 13 shows the curtailment in the combined JDA case at the different solar levels. The table breaks up the curtailment into total curtailment from the no solar cases and into a category showing what portion of that curtailment occurred due solely to the load following increase. In the combined (JDA Modeled) case the overall solar curtailment is 0.3% for Tranche 1 and 3% for Tranche 2. Overall, low levels of curtailment take place in the Combined (JDA Modeled) case.

Table 13. Combined (JDA Modeled) Curtailment

	Tranche 1	Tranche 2
Renewable Capacity (MW)	3,875	6,450
Solar Penetration (%)	4.8%	8.7%
Renewable (MWh)	7,564,719	13,591,705
Additional Curtailment from No Solar Case (MWh)	25,333	407,012
Additional Curtailment from No Solar Case (% of Total Solar Gen)	0.3%	3.0%
Portion of Additional Curtailment Only Due to Additional Load Following (MWh)	1,215	38,471
Portion of Additional Curtailment Only Due to Additional Load Following (% of Total Solar Gen)	0.02%	0.3%

VI. Summary

The Study results show the impact solar has on the DEC and DEP systems. As more solar is added, additional ancillary services in the form of load following are required to meet load in real time. This Study simulated both the DEC and DEP systems to determine the amount of load following that was needed to maintain the same level of flexibility excursions the system experienced before the solar was added. Then, the costs of the load following were calculated to determine SISC. This was conducted as an island for both DEC and DEP as well as a combined analysis assuming the JDA was used to economically produce the load following requirements. These inputs, methods, and results have been reviewed by the TRC as discussed in the TRC Report. The values in the Study provide information for the Companies to propose a SISC for its Avoided Cost Filing.

VI. Appendix

While having no impact on the rates being set in the Companies Avoided Cost filing, a third tranche was also simulated representing 3,931 MW in DEC and 5,519 MW in DEP. The results for the island and combined case are shown in Table A.1 for informational purposes. The DEC analysis shows that the cost of ramping needs begins to increase exponentially. By the time this penetration of solar is on the system, it is likely there will be a significantly different resource mix which may assist in the ramping needs and reduce the integration costs. Similar to the first two tranches, the combined JDA analysis for Tranche 3 brings these values down significantly.

Table A.1. Tranche 3 Results

	DEC Tranche 3	DEP Tranche 3
Total Solar (MW)	3,931	5,519
Flexibility Violations (Events Per Year)	2.6	0.6
Average SISC ($/MWh)	7.03	2.70
Incremental SISC ($/MWh)	15.44	3.32
Realized 10 Min Load Following Reserves **(Average MW Over Solar Hours Assuming 16 Hours)** (MW)	147	233
Additional Curtailment Due to Solar and Load Following (MWh)	444,474	2,932,656
Additional Curtailment Only Due to Additional Load Following (MWh)	230,458	206,563
Solar Generation (MWh)	8,878,524	11,872,220
Percentage of Solar Generation Curtailed (%)	5.01%	24.7%
Percentage of Solar Generation Curtailed Due to Additional Load Following (%)	2.60%	1.7%
Combined (JDA Modeled) Tranche 3 Average SISC ($/MWh)	2.36	2.70