Solar Integration Study

Final Report

12/15/2022

PREPARED FOR

Santee Cooper

PREPARED BY

Astrapé Consulting

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ABBREVIATIONS USED IN REPORT

ACE	Area Control Error
BAA	Balancing Authority Area
BESS	Battery Energy Storage System
CC	Combined Cycle Generator
CT	Combustion Turbine Generator
ELCC	Effective Load Carrying Capability
LOLE	Loss of Load Expectation
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
PRM	Planning Reserve Margin
SEEM	Southeastern Energy Exchange Market
SERVM	Astrapé's Strategic Energy and Risk Evaluation Model

EXECUTIVE SUMMARY

This report documents a study performed by Astrapé Consulting for Santee Cooper to determine the integration cost of the following tranches of solar penetration of the Santee Cooper systems:

1. 500 MW,
2. 1,000 MW,
3. 1,500 MW, and
4. 2,000 MW.

The studies were performed for two primary scenarios and two sensitivities. The two primary scenarios were:

1. The existing Santee Cooper system (modeled in 2026), and
2. The Santee Cooper system in 2029.

The study of the existing system determined the cost to integrate solar in the near-term future before the planned retirement of the Winyah coal plant, while the 2029 view represents the longer-term view after the retirement of the Winyah coal plant.

The two sensitivities included:

1. The impact of the inclusion of Battery Energy Storage Systems (BESS) as a means of potentially lowering integration costs, and
2. The impact of the Southeastern Energy Exchange Market SEEM on the integration costs.

The following summarizes the results of this study.

SOLAR INTEGRATION RESULTS

As discussed in the main body of the report, because of the extended processing associated with intra-hour modeling, this analysis was performed for Santee Cooper based on an islanded model of the Santee Cooper System, with inflexible CT resources used as a proxy for market interactions necessary to maintain a LOLE of 0.1 and represent capacity Santee Cooper can access during capacity shortage periods.

The existing system was modeled using a 2026 study year. The integration costs for the four solar tranches were calculated by determining the increase in production cost necessary to reduce the number of flexibility excursions[1] introduced by the solar tranche back down to levels in the base case.

[1] Flexibility excursions are events in which the capabilities of the system are unable to resolve a 5-minute movement of net load.

These integration costs were calculated using both an unoptimized[2] and an optimized[3] technique as explained in the Study Methodology section of the main report.

The table below shows the unoptimized and optimized results on both an average and an incremental[4] basis.

Table ES 1. Existing System Integration Costs[5]

Solar Penetration MW	Unoptimized Average Costs $/MWH	Unoptimized Incremental Cost $/MWH	Optimized Average Costs $/MWH	Optimized Incremental Cost $/MWH
500	0.08	0.08	0.08	0.08
1,000	3.32	6.57	2.38	4.68
1,500	4.85	7.69	3.20	4.73
2,000	9.86	24.15	6.26	14.99

The figure below shows the average and incremental solar integration costs for the optimized 2026 existing system.

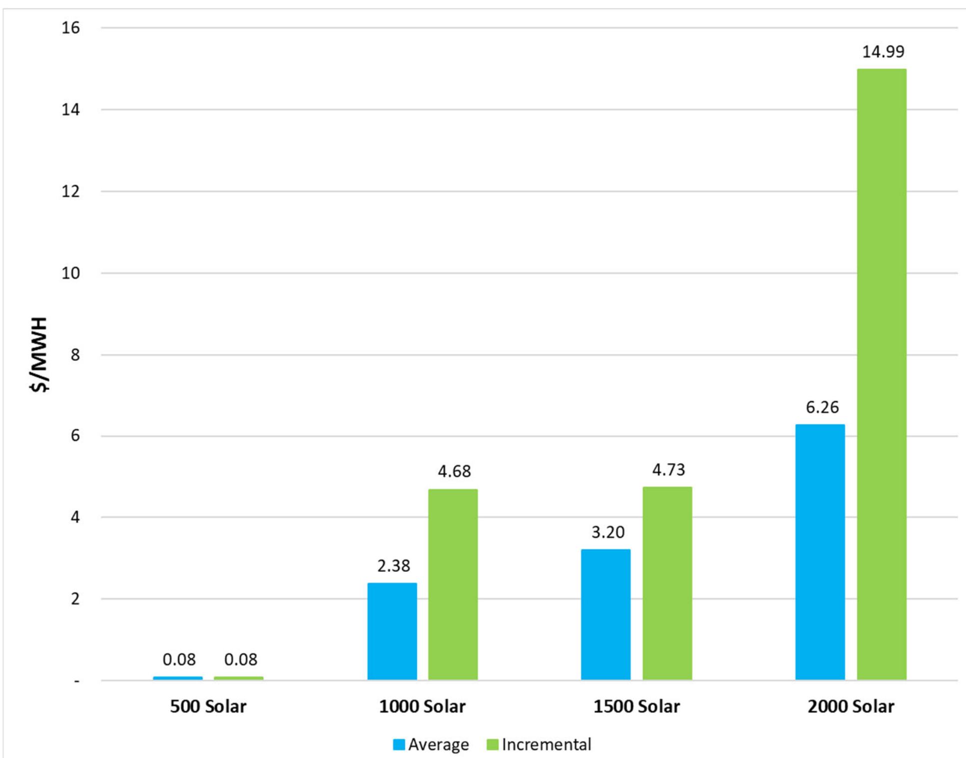

Figure ES 1. 2026 Existing System Integration Costs

[2] The unoptimized approach assumed uniform addition of operating reserves across hours 6-21 of all days.
[3] The optimized approach added operating reserves on a targeted basis to mitigate flexibility excursions.
[4] The incremental cost to implement the next 500 MW block of solar resources assuming the previous solar tranche has already been implemented.
[5] In 2026 dollars.

In addition to the cost of integration, the analysis also looked at the amount of generation curtailment that would be necessary because the system was unable to ramp down and/or decommit conventional resources to meet net load as a result of the addition of solar to the system. The table below shows the optimized generation curtailment associated with each of the solar tranches on the existing system.[6]

Table ES 2. Existing System Generation Curtailment

Solar Penetration MW	Generation Curtailment MWH	Curtailment As a % of Solar Generation
500	6	0.0%
1,000	8,522	0.4%
1,500	105,284	3.0%
2,000	525,829	10.6%

The system was then modeled using a 2029 study year and assuming that the Winyah coal units are retired and replaced with a 1181 MW Combined Cycle (CC) plant as well as a 341 MW Combustion Turbine (CT) plant. The table below shows the unoptimized and optimized results of this analysis on both an average and incremental basis.

Table ES 3. 2029 System Integration Costs[7]

Solar Penetration MW	Unoptimized Average Costs $/MWH	Unoptimized Incremental Cost $/MWH	Optimized Average Costs $/MWH	Optimized Incremental Cost $/MWH
500	0.40	0.40	0.40	0.40
1,000	0.71	1.01	0.57	0.75
1,500	1.31	2.53	0.92	1.61
2,000	2.46	5.89	1.70	4.06

The figure below shows the average and incremental integration costs for the optimized 2029 system.

[6] Curtailment for the unoptimized case is available in the main body of the report.
[7] In 2029 dollars.

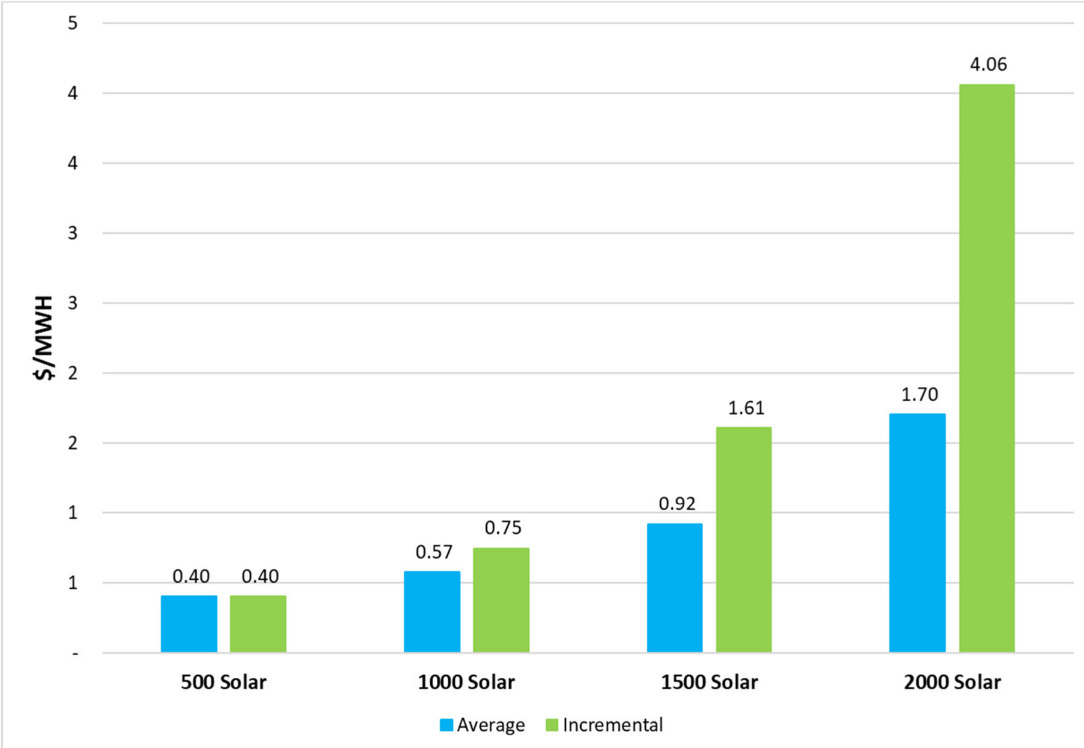

Figure ES 2. 2029 Future System Integration Costs

The table below shows the optimized generation curtailment associated with each of the solar tranches on the 2029 system.[8]

Table ES 4. 2029 System Generation Curtailment

Solar Penetration MW	Generation Curtailment MWH	Curtailment As a % of Solar Generation
500	542	0.0%
1,000	25,224	1.0%
1,500	150,507	4.1%
2,000	486,113	9.9%

In addition to the existing system and 2029 system scenarios, two sensitivities were run. The first was a battery sensitivity in which the 341 MW CT was replaced with 350 MW of batteries. The second was a sensitivity that attempted to model the new SEEM market. Both sensitivities were run for the 2029 system and both sensitivities were assumed to be available in the no solar case as well as the solar cases. As a result, the flexibility benefit afforded by the sensitivities (i.e., batteries or SEEM market) was achieved in the no solar case. The associated benefits were available to the system prior to the

[8] Curtailment for the unoptimized case is available in the main body of the report.

addition of solar and therefore did not accrue to solar as part of the solar integration costs. As a result, both sensitivities produced incremental integration costs consistent with the 2029 solar integration cost scenario as shown in the results section of the report.

CONCLUSIONS

As indicated above, the cost of integrating solar on the existing Santee Cooper system ranges from near zero (0.08$/MWH) at 500 MW of solar to approximately $5/MWH at 1,500 MW of solar, which is a distinct breakpoint for solar integration costs on the existing Santee Cooper system. Above that level of penetration, incremental integration cost increase significantly to approximately $15/MWH at 2,000 MW of solar. With the retirement of the Winyah coal facility and assuming it is replaced by the CT and CC combination modeled in this report, integration costs drop significantly. Under those conditions, incremental integration costs remain below $2/MWH through 1,500 MW of solar penetration and are approximately $4/MWH at 2,000 MW of solar. Similarly, there is a distinct breakpoint associated with generation curtailment that occurs between 1,000 MW of solar and 1,500 MW of solar. At 1,500 MW of solar between 3-4% of the solar generation would need to be curtailed, and at 2,000 MW of solar as much as 10% of the solar generation would need to be curtailed.

Upon examination of the study analysis, it is clearly demonstrated that:

1) Solar integration costs and associated generation curtailment increase with solar penetration, although the magnitude of those costs may vary depending upon the underlying system.[9]

2) The introduction of more flexible resources causes a reduction in the flexibility excursions of not only the solar tranches, but also the base case against which the solar tranches are benchmarked. For example, the base case flexibility excursions decrease from 5.7 events/year to 1.7 events/year by retiring the Winyah coal units and replacing them with the fast-responding combined cycle and combustion turbine. Similarly, the base case flexibility excursions decrease from 1.7 events/year to 0.132 events/year by adding the BESS resources and decreases 1.7 events/year to 0.7 events/year by introducing the SEEM market. The battery and SEEM sensitivities showed little to no improvement in solar integration cost beyond the 2029 Base Case because the improvement in flexibility achieved by those sensitivities is realized by the system even without the addition of solar. As such, the flexibility benefit obtained should be credited to the resource providing the flexibility benefit, not as a direct reduction in solar integration costs.

[9] Compare, for example, the relative integration costs of the existing system versus the 2029 system.

INTRODUCTION

The report documents the results of a study performed by Astrapé Consulting to determine the integration costs of various levels of solar penetration on the Santee Cooper system. The study examined the integration costs of the following tranches of solar resources:

1. 500 MW,
2. 1,000 MW,
3. 1,500 MW, and
4. 2,000 MW.

The integration costs were performed for two primary scenarios and two sensitivities. The two primary scenarios were:

1. The existing Santee Cooper system (modeled in 2026), and
2. The Santee Cooper system in 2029.

The existing system represents the cost to integrate solar in the near-term future before the planned retirement of the Winyah coal plant, while the 2029 view represents the longer-term view after the retirement of the Winyah coal plant.

The two sensitivities included:

1. The impact of the inclusion of BESS as a means of potentially lowering integration costs, and
2. The impact of SEEM on the integration costs.

STUDY FRAMEWORK

This study was performed using the Strategic Energy & Risk Valuation Model (SERVM) and its associated study framework. The SERVM framework combines an intra-hour production cost model coupled with Monte Carlo outage simulation and comprehensive scenario management that considers load and weather uncertainty in order to determine key reliability parameters such as Loss of Load Expectation (LOLE). The following describes the key parameters and uncertainties that are considered and how they are applied within the study framework.

INTRA-HOUR UNCERTAINTY

Solar integration analyses measure the cost impact of hour-to-hour ramps and moment to moment variations in output. Intra-hour modeling is required that takes into account both moment to moment load uncertainty as well as moment to moment renewable output uncertainty. For this study, the SERVM model performed 5-minute production cost simulations (12 per hour) over 8,760 hours, thus performing 105,120 economic dispatches for each 8,760-hour model simulation. During each of those

5-minute simulations, both load uncertainty and renewable resource uncertainty are applied, resulting in a net load volatility that simulates the moment-to-moment variations a system may experience in real life.

WEATHER UNCERTAINTY

To account for weather uncertainty, SERVM performs hourly production cost simulations using multiple load shapes representing historical weather years. The uncertainties that are modeled for each modeled weather year include load shapes, renewable profiles, and hydro availability. Load shapes for each weather year are developed to represent the expected future load response to the historical temperatures. For example, a 1990 weather year represents how loads would respond if 1990 weather were to repeat itself in the future. These load shapes are then scaled so that the median of the peak demands from the various weather year load shapes equals the study year weather normal peak load forecast. Similarly, renewable profiles and hydro schedules are developed to represent the expected future availability associated with the historical weather profile. For purposes of this study, 41 weather year scenarios were simulated representing weather conditions for the years 1980-2020.

ECONOMIC LOAD FORECAST ERROR

Economic Load Forecast Error represents the potential error in the weather normal peak load forecast associated with uncertainty in economic forecasts. The load forecast multipliers and probabilities were consistent with the PRM Study performed for Santee Cooper.

MONTE-CARLO OUTAGE ITERATIONS

SERVM uses Monte-Carlo techniques to simulate generator outages. Multiple hourly production cost simulations are run for each of the 205 load cases. With each outage iteration, random Monte-Carlo draws are made to determine the outage profile associated with that scenario. For purposes of this study, 25 outage draw iterations were made for each case. The specifics associated with how these outages were modeled are detailed in the Model Development section of this document.

As shown in the figure below, the SERVM uncertainty framework used for this study required at least 5,125 intra-hour production cost simulations for a single analytical run of the Santee Cooper system.

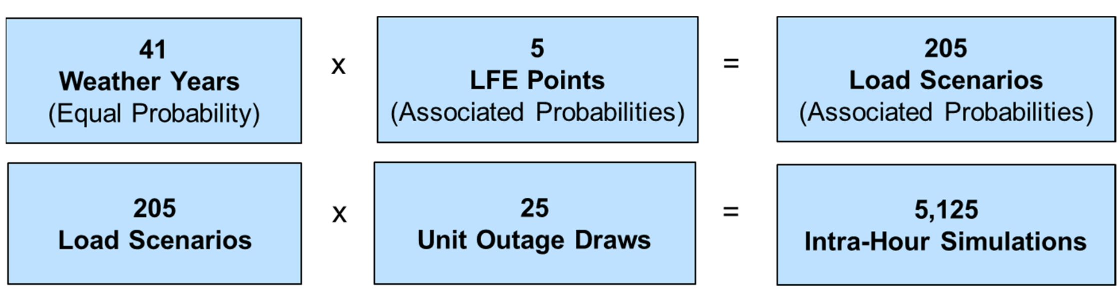

Figure 1. SERVM Uncertainty Framework

The Study Methodology section of this document describes the numerous "analytical runs" required to perform the solar integration analysis. This framework is identical to the framework used in the Reserve Margin Study performed for the Santee Cooper system.

MODEL DEVELOPMENT

Similar to the SERVM framework, the data utilized for this study was based upon the same SERVM data used for the Planning Reserve Margin (PRM) and Effective Load Carrying Capability (ELCC) analyses previously performed for Santee Cooper.

BASIS FOR MODEL DEVELOPMENT

For a description of the basic model used for this analysis and its associated inputs, reference is made to the study report "Reserve Margin and Effective Load Carrying Capability (ELCC) Study".

Additional model parameters needed for this analysis not included in that report are described below.

INTRA-HOUR LOAD VOLATILITY

The intra-hour load uncertainty applied in this study was based upon one year of actual historical 5-minute loads on the Santee Cooper system. The figure below shows a representation of this uncertainty as a function of system load.

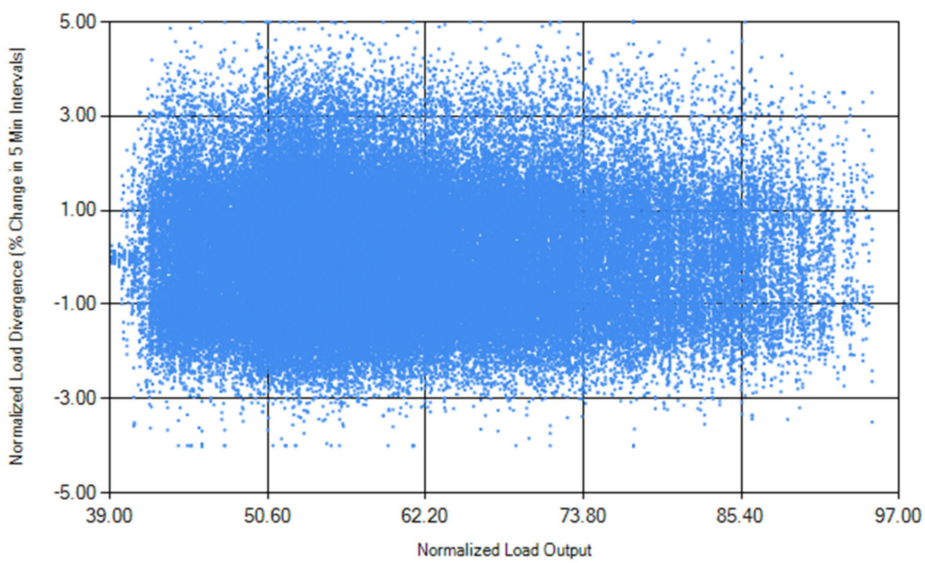

Figure 2. Intra-Hour Load Uncertainty

In this figure, the y-axis represents the potential deviation from the expected 5-minute load expressed in percent of annual peak load. Normalized load (i.e., percent load relative to the annual peak) is expressed on the x-axis. Based on the expected hourly load profile, a 5-minute load profile is developed within SERVM. Uncertainty is then applied to that expected 5-minute profile based on this uncertainty chart. As the figure demonstrates, each load point contains a distribution of possible uncertainty values. SERVM will duplicate this distribution so that at any given load point within the simulation, the 5-minute uncertainty could be anywhere along the y-axis plane in the chart. Thus, most 5-minute deviations would occur in the +/- 1-2% of peak load range. However, there may be deviations that are as much as 5% of peak load.

INTRA-HOUR SOLAR VOLATILITY

The solar volatility data used in this analysis was based on data from a neighboring utility which has extensive solar resources already deployed on their systems. The following figures show the solar volatility as a function of solar output for the 500 MW tranche of solar penetration evaluated in this analysis.

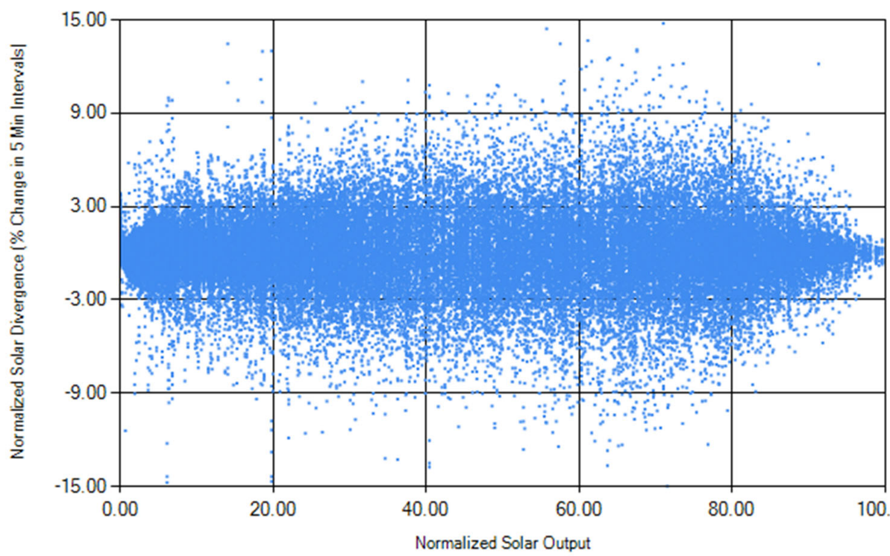

Figure 3. Solar Volatility for 500MW Tranche

The y-axis represents the potential deviation in solar output over a 5-minute period, expressed as a percent of normalized peak solar output (x-axis). As with load, SERVM develops an expected 5-minute solar profile based on the expected hourly profile. Uncertainty is then applied to that 5-minute expected solar profile based on the distributions in the solar volatility graph at that expected output. Thus, at a 500 MW penetration of solar, most 5-minute deviations will occur in the +/- 3% range (or ~15 MW). However, there may be deviations as high as 15% (or 75 MW).

The following three figures show the solar volatility for the 1,000 MW, 1,500 MW, and 2,000 MW solar penetration tranches, respectively.

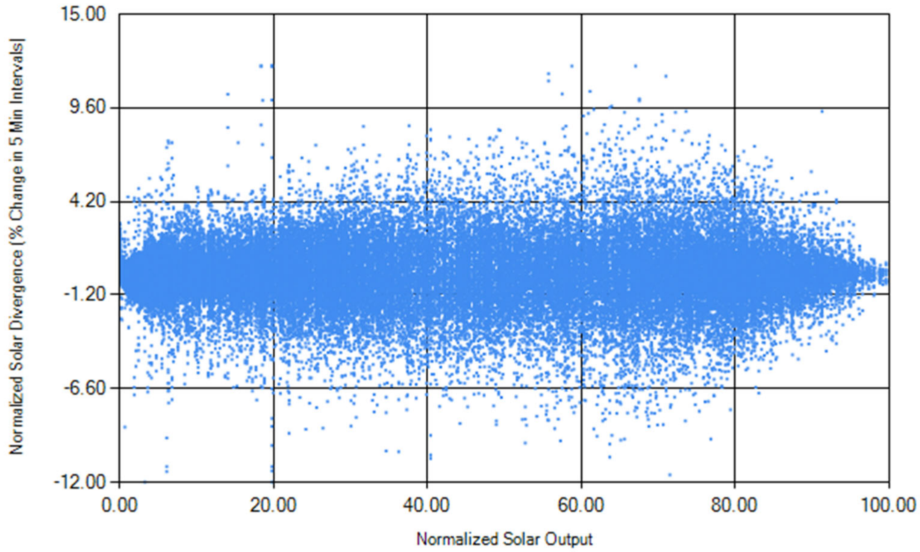

Figure 4. Solar Volatility for 1,000MW Tranche

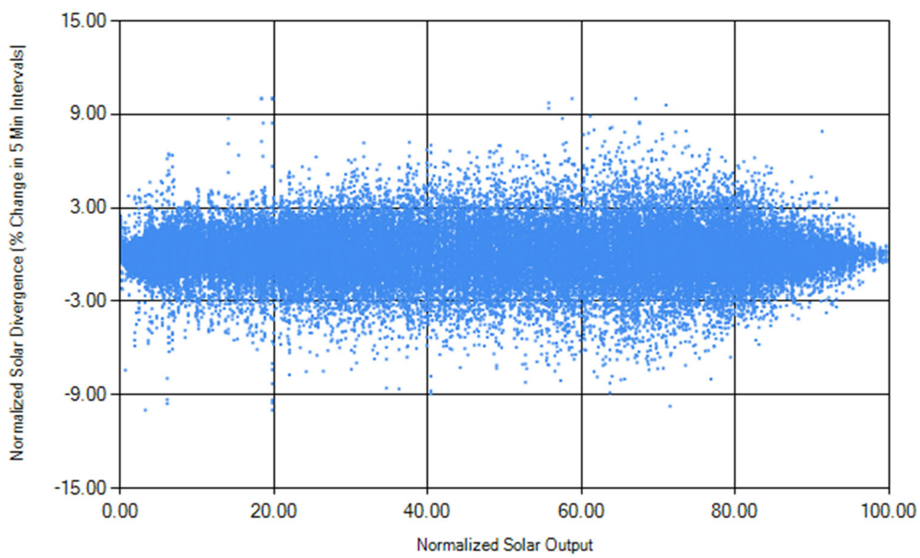

Figure 5. Solar Volatility for 1,500MW Tranche

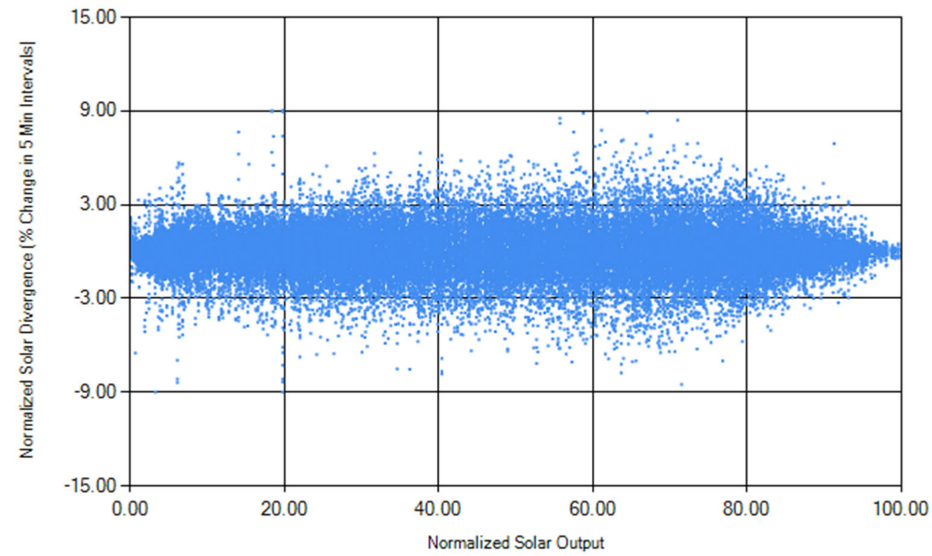

Figure 6. Solar Volatility for 2,000MW Tranche

As these figures demonstrate, the ***percent*** volatility decreases with increasing solar penetration, thus representing the benefit of geographic diversity achieved with greater penetrations of solar resources. This decrease in overall volatility due to the geographic diversity can also be seen by looking at the 95th percentile of 5-minute deviation from the forecasted solar output for each of the solar tranches as shown in the figure below.

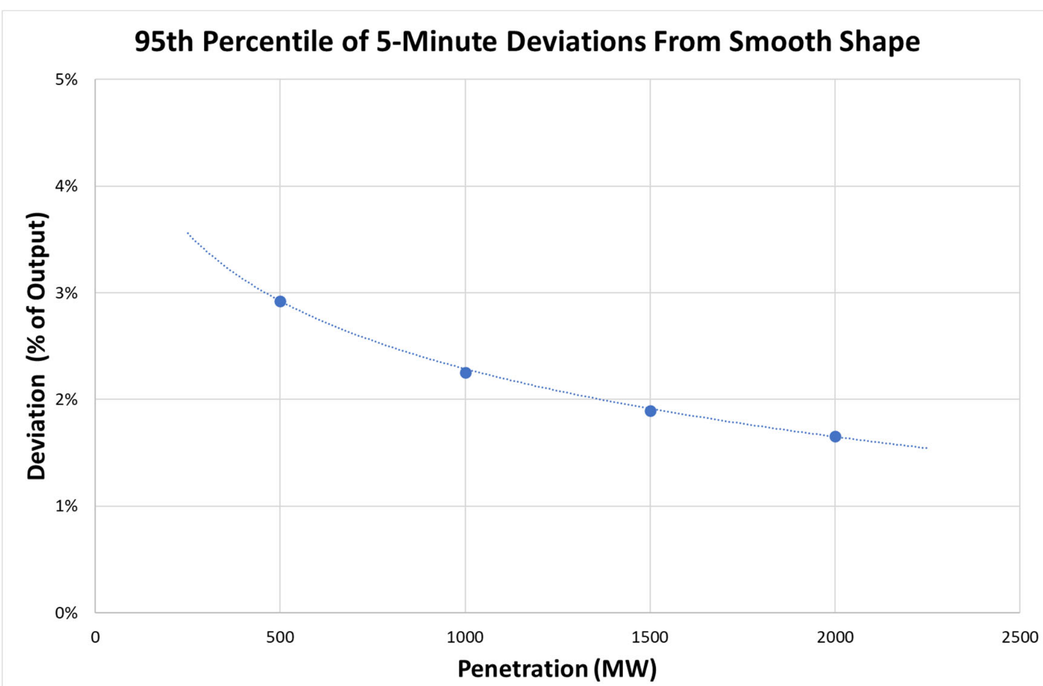

Figure 7. Solar Volatility Geographic Diversity Benefit

It should be noted, however, that this percent volatility is being applied to a larger tranche size, so that while the percent volatility may be decreasing, the absolute value of the potential 5-minute uncertainty (in MW) is increasing.

MARKET MODEL

Because of the extended processing associated with intra-hour modeling, this analysis was performed for Santee Cooper based on an islanded model of the Santee Cooper system. Being that Santee Cooper is its own balancing area, it is expected that it should carry adequate operating reserves to meet NERC standards on its own. A market model proxy was developed using a series of inflexible, 50MW Combustion Turbine (CT) resources priced in-between Santee Cooper's gas CTs and its oil CTs. These resources are added to maintain a LOLE of 0.1 and represent capacity Santee Cooper can access during capacity shortage periods.

These market proxy units serve two specific purposes. First, because Santee Cooper's existing resource mix is insufficient to reach the 17% PRM, a portion of these proxy units represent the acquisition or purchase of firm capacity necessary to meet that requirement. The remainder of the market proxy units represent the day ahead and/or hourly purchases that may be made from time to time to ensure reliability. Although no distinction was made between these two purposes within the analysis, the combined level of market units modeled was calibrated for each scenario so that the annual LOLE was 0.1 days/year and the monthly distribution of LOLE roughly equaled that which existed in the reserve margin study base case.

As with the PRM, it should be recognized that there is uncertainty associated with the availability and flexibility of such market purchases.

OTHER DATA UPDATED

Although the same database used in the Santee Cooper PRM and ELCC studies was used as the basis for this study, there were several variables for thermal resources for which a closer examination was warranted. These are performance and cost variables that would affect the intra-hour performance as well as the cost to mitigate flexibility excursions. Among those variables that were examined more closely and updated as necessary were:

- Minimum unit capacities
- Ramp rates
- Heat Rates
- Fuel Costs
- Startup Costs
- Variable O&M
- Startup times

STUDY METHODOLOGY

The objectives of the solar integration study are to determine the amount and associated cost of operating reserves necessary to integrate a given tranche of solar resources while maintaining the same level of real-time reliability that would be experienced on the system without the solar resources. In other words, the addition of solar resources should not increase the pressure on the system towards being unable to maintain real time system reliability. In the real world, this real-time reliability is measured in terms of NERC Reliability Standards. In the modeling world, this real-time reliability is measured in terms of flexibility excursions (see below) with the objective that both the modeled system with the solar resources and the modeled system without the solar resources would have the same level of flexibility excursions.

FLEXIBILITY EXCURSIONS

Within SERVM, a flexibility excursion occurs whenever the model cannot meet an unexpected increase in net load on a 5-minute basis with available resources, even though there are sufficient installed capacity resources available to meet the load. This likely occurs with an unexpected decrease in renewable output. 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 can meet both load and minimum operating reserve requirements. Any periods in which generation cannot ramp up to meet an increase in net load but there is sufficient installed capacity on the system are recorded as flexibility excursions. Similarly, any time generators cannot ramp down enough to meet decreases in net load the system will curtail generation, but this is not a flexibility excursion. This inability to balance load and resources occurs because (a) available resources needed to meet the change in load from one 5-mintue interval to the next were offline and could not be brought online in sufficient time, and/or (b) the online resources had insufficient ramping capability to meet the change in load from one 5-minute interval to the next.

While a flexibility excursion within the model represents an inability to balance load and resources over a 5-minute period, it does not represent a real-world loss of load event. Rather, it is more accurate to say it is representative of a potential Area Control Error (ACE) deviation. If ACE deviations become too frequent and high in magnitude, a Balancing Authority Area (BAA) may not be able to meet the requirements of NERC Reliability Standards. Thus, while not necessarily a representation of compliance or non-compliance with NERC Reliability Standards, the performance results would be correlated with the ability to remain in compliance with those standards. A flexibility excursion, therefore, would represent negative pressure on the system’s ability to meet real time NERC Reliability Standards. As such, the goal of the integration study would be to establish operating parameters (and determine associated costs) necessary for the system to not have any greater risk with the solar resources than the system has without the solar resources.

FLEXIBILITY EXCURSION BENCHMARK

While it is not necessary to eliminate all flexibility excursions from the model, the objective of the study is to ensure that flexibility excursions do not exceed that which would be normally expected on the system without the solar resources. To establish this benchmark, a "base case" or "no solar" case is developed that is calibrated at a Loss of Load Event (LOLE) threshold of 0.1 days/year and the flexibility excursions associated with this case are determined and established as a benchmark for the analysis.

To ensure that this benchmark is representative of the actual system, the model was calibrated so that the organic level of operating reserves is consistent with that typically seen in the Santee Cooper system. To establish this organic level of operating reserves, Santee Cooper provided a year's worth of historical operating reserves.

The average level of 60-minute operating reserves across the year was approximately 450 MW/hr. Thus, the no solar case was calibrated to this level for purposes of establishing the flexibility excursion benchmark by changing the level of targeted operating reserves on the system.

DETERMINING AND MITIGATING TRANCHE-LEVEL FLEXIBILITY EXCURSIONS

The addition of solar resources on the system introduces additional intra-hour volatility. Without any change in the targeted operating reserves, this additional volatility manifests itself in additional flexibility excursions, especially when the system is calibrated back to a LOLE threshold of 0.1 days/year (through either additional load or the removal of generation). These violations represent the unmitigated flexibility excursions on the system associated with the tranche of solar resources.

To mitigate these flexibility excursions, additional operating reserves – specifically 10-minute operating reserves – are added in appropriate time periods as required to reduce the flexibility excursions on the system to the benchmark level. Two approaches were used to accomplish this mitigation, referred to herein as the unoptimized approach and the optimized approach.

The unoptimized approach, which is simpler to implement in both the model, as well as in actual practice, adds operating reserves on a uniform basis across hours 6 through 21.

The optimized approach is more complicated but results in lower overall integration costs. The optimized approach adds operating reserves on a targeted basis with the goal of reducing the flexibility excursions to the benchmark level. This was done on an hour-by-hour basis, with each hour of each month having a separate operating reserve target.

CALCULATING INTEGRATION COSTS

To ensure that integration costs are not impacted by the economic impact associated with the renewable resource, the integration costs are determined by comparing the production cost of the system in the unmitigated solar case with the production cost of the system in the mitigated solar case. This increase in production cost is then divided by the MWh of renewable energy to calculate integration costs as follows:

$$IC = (PC_{mitigated} - PC_{unmitigated}) / MWH_{renewable}$$

Were

IC = integration costs in $/MWH

$PC_{mitigated}$ = the production cost ($) of the mitigated system

$PC_{unmitigated}$ = the production cost ($) of the unmitigated system

$MWH_{renewable}$ = the total energy (MWH) of the renewable tranche

STUDY RESULTS

The following outlines the results of the solar integration analysis.

EXISTING SYSTEM

As described in the Study Methodology section above, the solar integration costs for the Santee Cooper system in its current configuration was evaluated using a 2026 study year.

UNMITIGATED FLEXIBILITY EXCURSIONS

For each of the solar penetration tranches as well as the no solar case, the flexibility excursions of the existing system were determined. For the no solar case, the base case used in the PRM and ELCC studies was modified by removing all existing renewable resources and adding in the market model resources. The case was then calibrated by removing market model resources monthly until the annual LOLE reached approximately 0.1 days/year with a monthly LOLE distribution roughly equal to the monthly LOLE profile produced in the PRM study.

The table below shows the resulting flexibility excursions (in events per year) for the no solar case and each of the solar tranche cases.

Table 1. Existing System Unmitigated Flexibility Excursions

Case	Flexibility Excursions
No Solar	5.7
500 MW Solar	5.8
1,000 MW Solar	9.6
1,500 MW Solar	14.7
2,000 MW Solar	21.3

As the table shows, the flexibility excursion benchmark from the no solar case is 5.7 events per year. The table also demonstrations the increase in unmitigated flexibility excursions as solar penetration increases.

The figure below shows the flexibility excursions by month.

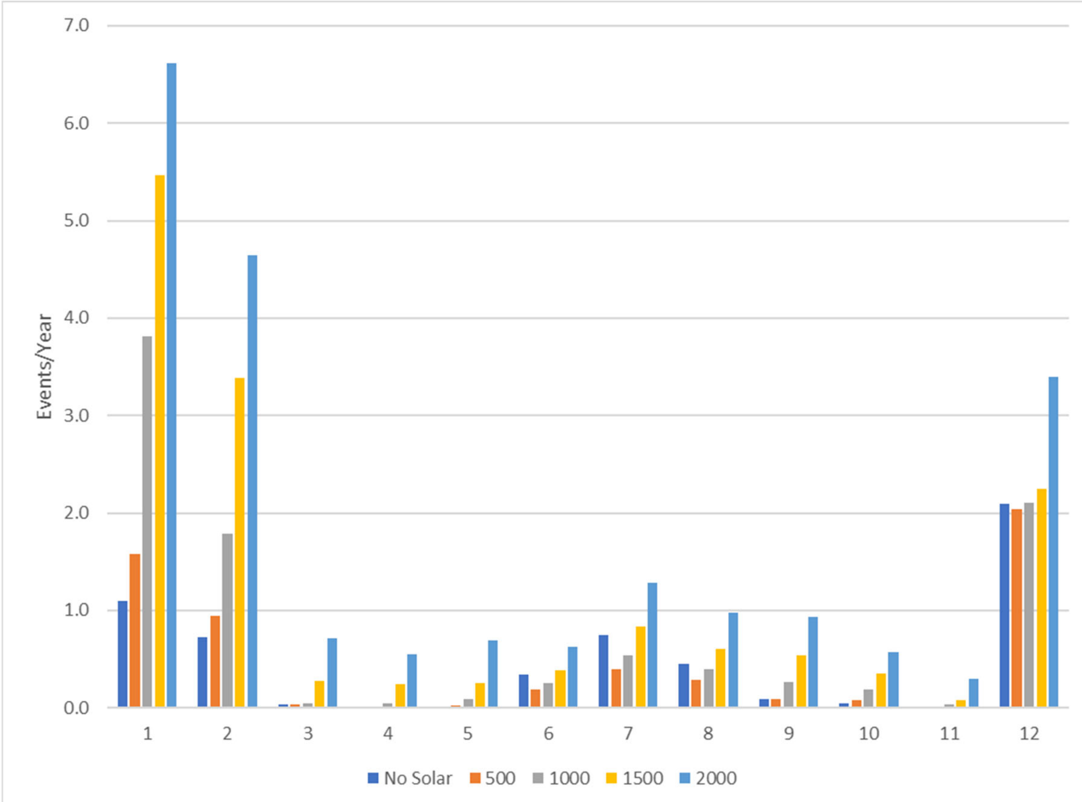

Figure 8. Existing System Flexibility Excursions by Month

MITIGATION

To return each of the four solar tranches back to a level of 5.7 flexibility excursions per year, 10-minute operating reserves were added in various hours of the year as necessary. Once mitigated to the 5.7 flexibility excursions, the integration costs were calculated as described in the Study Methodology section above.

As discussed in the Study Methodology section above, this process was performed in two different ways. First, referenced herein as the unoptimized results, the operating reserves were added in a uniform fashion across the solar hours. The table below shows the results of this analysis, with explanations for the various columns following the table.

Table 2. Existing System Unoptimized Results

Solar Penetration MW	Integration Costs $/MWH	Incremental Cost $/MWH	Incremental Operating Reserves MW	Generation Curtailment MWH	Curtailment As a % of Solar Generation
500	0.08	0.08	2	6	0.0%
1,000	3.32	6.57	17	8,536	0.4%
1,500	4.85	7.69	43	119,100	3.2%
2,000	9.86	24.15	65	579,822	11.7%

The column labeled "Integration Costs" represents total cost per MWH of solar (above the cost of the resource itself) to integrate the entire tranche of solar.

The column labeled "Incremental Cost" represents the incremental cost to implement the next 500 MW block of solar resources assuming the previous solar tranche has already been implemented. The column labeled "Incremental Operating Reserves" is the average increase in operating reserves realized across the 8,760-hour year.[10]

The column labeled "Generation Curtailment MWH" represents the total MWH increase (over the no solar case) in generation curtailment (i.e., the amount of undeliverable energy due to system bottom-out[11] conditions) resulting from the addition of the solar to the system and the associated mitigation efforts.

The column labeled "Curtailment as a % of solar generation" represents the total amount of generation curtailment as a percent of expected solar generation.

The second process optimized the addition of operating reserves, adding operating reserves on a targeted basis in the hours needed to return the system to the benchmark flexibility excursion level. The following table shows the results of this analysis and calculation.

Table 3. Existing System Optimized Results

Solar Penetration MW	Integration Costs $/MWH	Incremental Cost $/MWH	Incremental Operating Reserves MW	Generation Curtailment MWH	Curtailment As a % Solar Generation
500	0.08	0.08	2	6	0.0%
1,000	2.38	4.68	16	8,522	0.4%
1,500	3.20	4.73	29	105,284	3.0%
2,000	6.26	14.99	39	525,829	10.6%

As can be seen by comparing the two tables, the optimization process results in lower overall integration costs.

The figure below shows a graphical representation of the average and incremental integration costs as presented in the optimized table above.

[10] Note that this does not represent the increase in targeted operating reserves, which were only added in hours needed to achieve the reduction in flexibility excursions. The additional realized reserves are less than the additional targeted reserves because of the hours where the targets were already met during shoulder and off-peak hours.
[11] Bottom out conditions occur when the net load of the system is at or below the point at which all online resources have reduced output to their lowest stable operating condition.

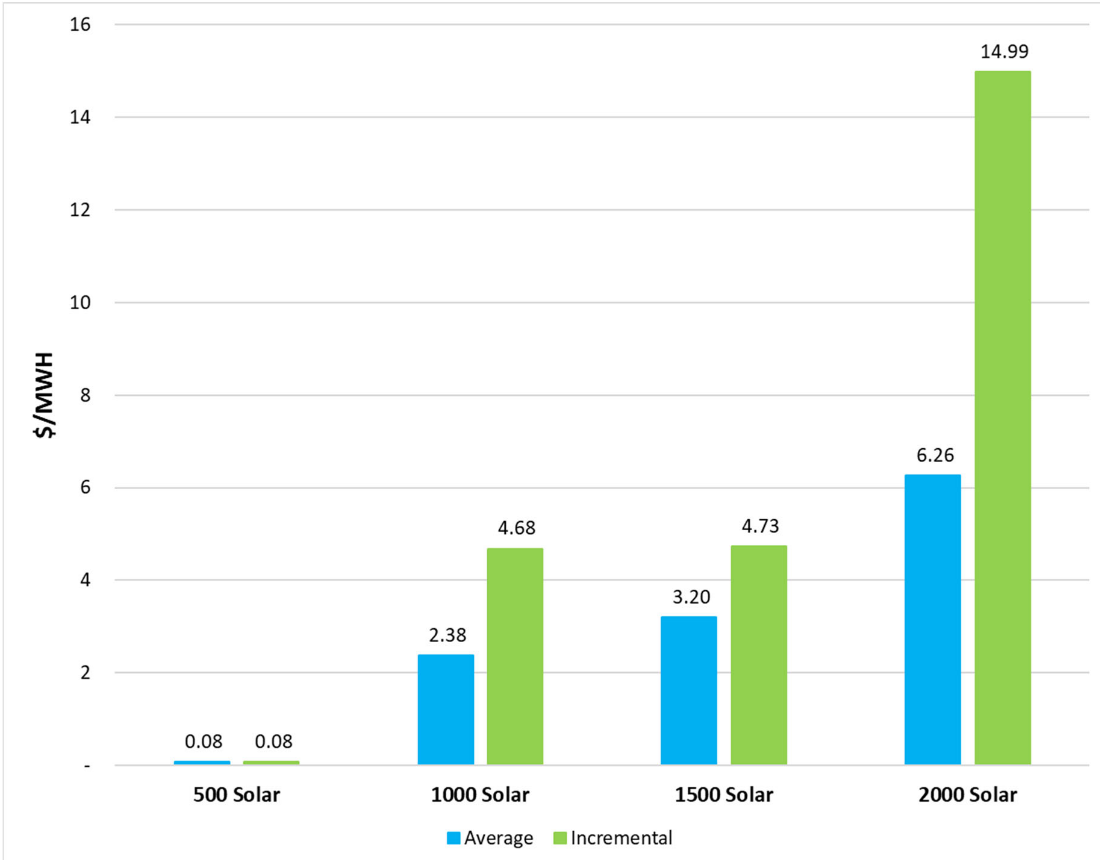

Figure 9. Existing System Optimized Integration Costs

2029 FUTURE SYSTEM

As described in the Study Methodology section above, the solar integration costs for the Santee Cooper system were also evaluated using a 2029 study year, with the Winyah coal plant retired and replaced with a combination of a 1,181 MW CC and a 341 MW CT to maintain approximately 0.1 days/year LOLE.

UNMITIGATED EXCURSIONS

Using the same process as was done for the existing system, the no solar and unmitigated solar tranche flexibility excursions were determined for the 2029 study year. The table below shows the resulting flexibility excursions (in events per year) for the no solar case and each of the solar tranche cases.

Table 4. 2029 Unmitigated Flexibility Excursions

Case	Flexibility Excursions
No Solar	1.7
500 MW Solar	1.8
1,000 MW Solar	2.5
1,500 MW Solar	3.7
2,000 MW Solar	6.3

As the table shows, the flexibility excursion for the no solar as well as each of the solar tranches is less than that of the existing system. This is due to the exceptional ramp rate flexibility of both the new CC as well as the new generic CT.

The figure below shows the flexibility excursions by month.

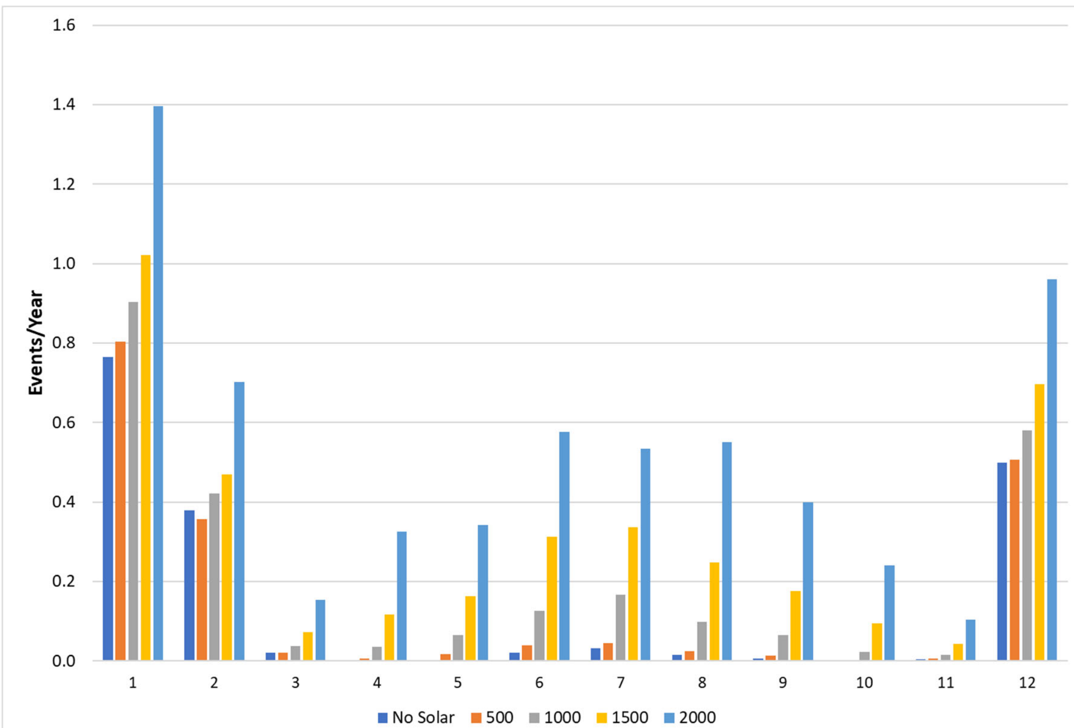

Figure 10. 2029 Flexibility Excursions by Month

MITIGATION

To return each of the four solar tranches back to a level of 1.7 flexibility excursions per year, 10-minute operating reserves were added in various hours of the year as necessary. Once mitigated to the 1.7 flexibility excursions, the integration costs were calculated as described in the Study Methodology section above. As with the existing system, this process was performed on both an unoptimized and optimized basis.

The following tables show the unoptimized and optimized results, respectively.

Table 5. 2029 Unoptimized Results

Solar Penetration MW	Integration Costs $/MWH	Incremental Cost $/MWH	Incremental Operating Reserves MW	Generation Curtailment MWH	Curtailment As a % Solar Generation
500	0.40	0.40	7	542	0.0%
1,000	0.71	1.01	33	25,124	1.0%
1,500	1.31	2.53	55	149,494	4.0%
2,000	2.46	5.89	74	489,059	9.9%

Table 6. 2029 Optimized Results

Solar Penetration MW	Integration Costs $/MWH	Incremental Cost $/MWH	Incremental Operating Reserves MW	Generation Curtailment MWH	Curtailment As a % Solar Generation
500	0.40	0.40	7	542	0.0%
1,000	0.57	0.75	30	25,224	1.0%
1,500	0.92	1.61	50	150,507	4.1%
2,000	1.70	4.06	63	486,113	9.9%

The figure below shows a graphical representation of the average and incremental integration costs as presented in the optimized table above.

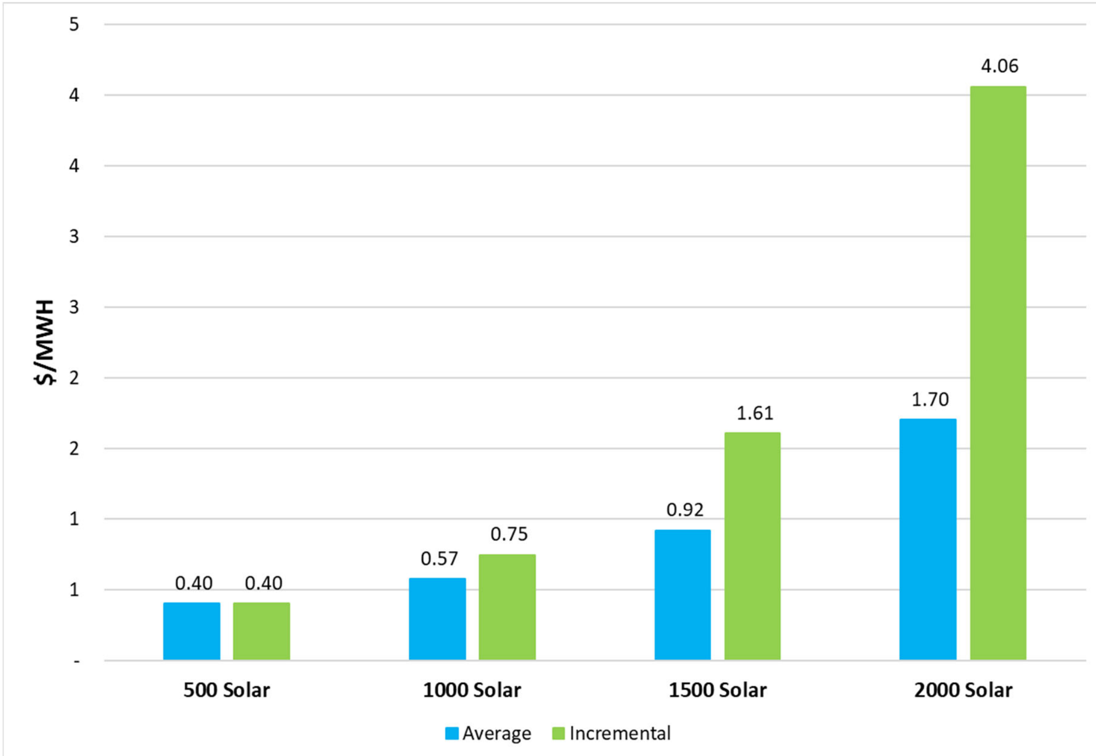

Figure 11. 2029 Optimized Integration Costs

BESS SENSITIVITY

A sensitivity on the 2029 future system analysis was performed in which the 341 MW CT was replaced with a 350 MW battery with four (4) hours of storage.[12] Because the battery, which has significant flexibility, was available in the no solar as well as the solar tranche cases, the flexibility benchmark from the no solar case decreased. The table below shows the unmitigated flexibility excursions of the no solar case and the four solar tranches.

Table 7. BESS Sensitivity Unmitigated Flexibility Excursions

Case	Flexibility Excursions
No Solar	0.132
500 MW Solar	0.243
1,000 MW Solar	0.609
1,500 MW Solar	1.086
2,000 MW Solar	1.842

[12] This implementation assumes that batteries are being added to the system for reasons other than just to increase flexibility on the system (e.g., to meet corporate goals, for capacity purposes, etc.).

The tables below show the unoptimized and optimized integration costs for this sensitivity, respectively.

Table 8. BESS Sensitivity Unoptimized Results

Solar Penetration MW	Integration Costs $/MWH	Incremental Cost $/MWH	Incremental Operating Reserves MW	Generation Curtailment MWH	Curtailment As a % Solar Generation
500	0.86	0.86	11	52	0.0%
1,000	1.15	1.43	45	2,432	0.1%
1,500	1.61	2.54	79	42,038	1.1%
2,000	3.20	7.99	119	232,739	4.7%

Table 9. BESS Sensitivity Optimized Results

Solar Penetration MW	Integration Costs $/MWH	Incremental Cost $/MWH	Incremental Operating Reserves MW	Generation Curtailment MWH	Curtailment As a % Solar Generation
500	0.86	0.86	11	52	0.0%
1,000	0.72	0.57	43	2,705	0.1%
1,500	1.57	3.28	77	45,669	1.2%
2,000	2.76	6.33	110	236,907	4.8%

As the table demonstrates, because the flexibility benefit of the batteries was already realized in the no solar case, there is no significant integration cost benefit associated with the addition of the batteries. To understand why, it should be noted that these results presume the battery exists for reasons other than solar integration (i.e., the battery comes first before the addition of the solar). While the no solar base case (without batteries) had a flexibility excursion metric of 1.7 events/year, the no solar base case (with batteries) had a flexibility excursion metric of 0.132 events/year.

As a sensitivity, the operating reserve target of the no solar base case (with batteries) was reduced until the flex metric reached ~1.7 events/year (consistent with the case without batteries). The results of that analysis are shown in the table below.[13]

[13] This sensitivity was not optimized (i.e., it uses uniform operating reserves across solar hours) and thus comparable to the unoptimized base scenario (without batteries).

Table 10. Battery Sensitivity with Adjusted Base Case Operating Reserve Targets

Solar Penetration MW	Integration Costs $/MWH	Incremental Cost $/MWH	Incremental Operating Reserves MW	Generation Curtailment MWH	Curtailment As a % Solar Generation
500	0.69	0.69	8	120	0.0%
1,000	0.71	0.73	38	2,328	0.1%
1,500	1.42	2.85	67	38,911	1.1%
2,000	2.24	4.68	95	209,496	4.2%

These (unoptimized) results are in line with the 2029 base scenario results, further demonstrating that when batteries are added for reasons other than renewable integration such that the base case system without renewables has already realized the flexibility benefits of the batteries, there is not a significant incremental integration cost benefit compared to the 2029 case that already included a flexible combined cycle and flexible CT resource. However, it should be noted that because of the flexibility of the new combined cycle as compared to the retired coal units, the overall flexibility in 2029 is better than 2026 as evidenced by comparing the no solar case flexibility excursions in the two cases.

SEEM SENSITIVITY

A sensitivity on the 2029 future system analysis was also performed considering the implementation of the SEEM market. The SEEM market is currently expected to allow 15-minute scheduling. Therefore, to simulate this market, the first 200 MW of the 50 MW market CTs, which were modeled with no flexibility and a 60-minute start time, were modified to have full flexibility and a 20-minute start time to reflect the transaction and scheduling implementation time. Thus, up to 200 MW of fully flexible "SEEM" market capacity would be available with a 20-minute notice. The table below shows the flexibility excursions for the no solar as well as the unmitigated solar tranches.

Table 11. SEEM Sensitivity Unmitigated Flexibility Excursions[14]

Case	Flexibility Excursions
No Solar	0.7
1,000 MW Solar	2.2
1,500 MW Solar	3.3
2,000 MW Solar	5.8

As with the BESS sensitivity, there is an immediate reduction in the flexibility excursions of the no solar case (0.7 events/year) as compared to the 2029 scenario (1.7 events/year). Thus, the flexibility benefit associated with the SEEM market is available to both the no solar case as well as the solar

[14] This sensitivity was only performed for the 1,000 MW, 1,500 MW, and 2,000 MW tranches.

tranches. The integration costs of this sensitivity are shown in the table below.[15] As the table demonstrates, the results are comparable to the 2029 unoptimized results.

Table 12. SEEM (Unoptimized) Sensitivity Results

Solar Penetration MW	Integration Costs $/MWH	Incremental Cost $/MWH	Incremental Operating Reserves MW	Generation Curtailment MWH	Curtailment As a % Solar Generation
1,000	0.59	0.59	40	27,348	1.1%
1,500	1.19	2.40	63	118,473	3.9%
2,000	2.45	6.22	72	448,634	9.1%

[15] This sensitivity was not optimized.

CONCLUSIONS

As indicated above, the cost of integrating solar on the existing Santee Cooper system ranges from near zero (0.08$/MWH) at 500 MW of solar to approximately $5/MWH at 1,500 MW of solar, which is a distinct breakpoint for solar integration costs on the existing Santee Cooper system. Above that level of penetration, incremental integration cost increase significantly to approximately $15/MWH at 2,000 MW of solar. With the retirement of the Winyah coal facility and assuming it is replaced by the CT and CC combination modeled in this report, integration costs drop significantly. Under those conditions, incremental integration costs remain below $2/MWH through 1,500 MW of solar penetration and are approximately $4/MWH at 2,000 MW of solar. Similarly, there is a distinct breakpoint associated with generation curtailment that occurs between 1,000 MW of solar and 1,500 MW of solar. At 1,500 MW of solar between 3-4% of the solar generation would need to be curtailed, and at 2,000 MW of solar as much as 10% of the solar generation would need to be curtailed.

Upon examination of the study analysis, it is clearly demonstrated that solar integration costs increase with solar penetration, although the magnitude of those costs may vary depending upon the underlying system.[16] To measure the integration costs, the underlying resources must be included in both the base case (i.e., no solar) and the solar tranche cases.

The introduction of a more flexible resource causes a reduction in the flexibility excursions of not only the solar tranches, but also the base case against which the solar tranches are benchmarked. For example, the base case flexibility excursions decrease from 5.7 events/year to 1.7 events/year by retiring the Winyah coal units and replacing them with the fast-responding combined cycle. Similarly, the base case flexibility excursions decrease from 1.7 events/year to 0.132 events/year by adding the BESS resources and decreases 1.7 events/year to 0.7 events/year by introducing the SEEM market. The battery and SEEM sensitivities showed little to no improvement in solar integration cost beyond the 2029 Base Case because the improvement in flexibility achieved by those sensitivities is realized by the system even without the addition of solar. As such, the study assumes the flexibility benefit obtained should be credited to the resource providing the flexibility benefit, and not provided to the solar in the form of a reduction in solar integration costs.

In conclusion, Astrape recommends using the optimized integration costs from the existing 2026 case along with the 2029 base case results when the Winyah coal plant is retired, and additional resources are added to the system.

[16] Compare, for example, the relative integration costs of the existing system versus the 2029 system.