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Santee Cooper IRP Stakeholder Process 2024-2026

Stakeholder Working Group Meeting #9 – Meeting Summary

Date: October 14, 2025

Time: 10:03 am – 12:45 pm EDT

Location: Virtual Meeting via Zoom, Vanry Associates facilitating

Meeting: Santee Cooper Stakeholder Working Group Session #9

This summary includes meeting logistics, presentations, and discussions.
It is organized into the following sections:

- Meeting Information & Materials
- Session Participation
- Topics, Presenters, and Discussion
- Commitments and Next Steps
- Appendix - List of External Stakeholder Working Group Members & June Meeting Attendees

Meeting Information & Materials

The Santee Cooper Resource Planning team held its ninth Integrated Resource Plan (IRP) Stakeholder Working Group (SWG) meeting on Tuesday, October 14, 2025. The IRP Stakeholder Working Group is integral to Santee Cooper's commitment to engage stakeholders in its ongoing integrated resource planning process. The presentation shared during the meeting is posted to the Stakeholder Working Group section of the Santee Cooper 2024-2026 IRP Stakeholder Process webpage, along with summaries from the first seven working group meetings.

Session Participation

The Stakeholder Working Group includes a set membership of organizations representing diverse interests and perspectives, including government, regulatory agencies, and environmental, social, and customer groups. The Santee Cooper Resource Planning team invited each organization to join the working group and assign a primary and secondary member

Appendix A lists the working group member organizations and the members who attended the October 14th meeting.

Topics, Presenters, and Discussion

The presentation, which included the meeting agenda and associated timing, was emailed to members on October 10, 2025.

Welcome and Agenda

– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart Ramsay opened the meeting by welcoming attendees and remarking that this was already the ninth stakeholder working group session. He indicated that Clay would review working group business and the 2025 IRP update, followed by a break, Discussion of Act 41 legislative impacts, an update on the wind study from Bob and Clay, another brief break, and then presentations from Joel Dison on reserve margin and ELCC, along with an overview of the integration study before wrapping up around 1 p.m. Stewart noted extra time was built in to allow for extended discussion if needed. Then he transitioned the meeting to Clay to begin the first agenda item.

Working Group Business

– Clay Settle, Manager, Resource Planning, Santee Cooper

Clay Settle began with a review of outstanding action items. Stakeholders had been invited to propose topics for the November General Notice Meeting, but no suggestions have been received to date. In response to previous feedback, the format of the general notice meetings has been adjusted to improve accessibility: scheduled later in the day, shortened in duration, and focused on higher-level content to encourage broader public participation.

He confirmed that the action item from meeting seven, providing a list of drivers behind changes in fuel price forecasts, had been completed in meeting eight, where Bob Davis (Executive Consultant, nFront) presented the contributing factors prior to the 2025 IRP Update filing. The request to evaluate sensitivity, allowing the model to select the joint combined-cycle unit as a resource option, was also fulfilled. That capability was implemented across all portfolios except the 2023 Preferred Portfolio Update, providing greater modeling flexibility.

Clay reported that the wind feasibility study remains in progress. Although a more comprehensive update had been planned for this session, that analysis is still underway. A high-level overview will be presented, and the final results will be brought forward at the next stakeholder meeting. He also noted that one stakeholder had offered to share information relevant to ITC modeling for renewable resources, but no material has yet been provided. Santee Cooper remains open to reviewing and incorporating such data when available.

Finally, Clay introduced a preliminary schedule of stakeholder working group meetings extending through the filing of the 2026 Triennial IRP. The revised plan adds a February meeting to allow a more deliberate review of required topics and commission-ordered commitments. He concluded by once again outlining the presentations and discussions to follow.

Review 2025 IRP Update

– Clay Settle, Manager, Resource Planning, Santee Cooper

Clay presented a detailed review of the 2025 IRP update, emphasizing the continued need for substantial new capacity beginning in the 2027 winter season and exceeding 2,000 MW by the mid-2030s. The analysis reaffirmed Santee Cooper's winter-peaking profile, in which total winter demand is defined as the 2025 load forecast plus an 18% planning reserve margin. Across all modeled portfolios, several resource additions were consistent: the joint combined-cycle project, an additional combined-cycle unit in the mid-2030s, [Winyah] LM6000 combustion turbines, new peaking capacity in the mid-to-late 2030s, and approximately 300 MW of battery storage by the late 2020s. Variations across portfolios primarily reflect regulatory scenarios; for example, the 2024 GHG Rule case drives earlier coal retirement, leading to greater peaking capacity and additional solar with limited wind.

He explained that portfolio evaluations considered both system cost and performance metrics. The 2025 Optimized Portfolio produced the lowest net-present system cost, with the 2025 Portfolio Update and the 2025

Portfolio with Solar close behind. Composite rankings across economic, reliability, and environmental measures placed the 2024 Portfolio Update and the 2025 Optimized Portfolio jointly first, each with an average rank of 2.5. Clay noted that continuing to implement cost-effective solar supports fuel diversification and mitigates exposure to fuel-price volatility and potential future environmental constraints. Deferring Winyah's retirement to the end of 2034 under current EPA rules enables staggered timing of the two additional 1-on-1 combined cycles into the mid-2030s, improving capital pacing while aligning additions with observed load growth.

- Findlay Salter (Office of Regulatory Staff) asked to clarify whether the 2025 Portfolio with Solar is actually less expensive than the 2025 Portfolio Update, noting that the figures appear similar but that the solar portfolio seems about $0.4 billion lower in net present value. Clay clarified that the cost comparisons were referenced against the 2023 Re-optimized Portfolio, not directly between the 2025 portfolios. When aligned correctly, the 2025 Optimized Portfolio is the least expensive, followed by the 2025 Portfolio Update, and then the 2025 Portfolio with Solar. Bob added that the 2025 Portfolio Update performs best under load sensitivities, and while it ranks lower on several other metrics, its overall performance is on par with the 2025 Optimized Portfolio.

Clay continued by explaining the projected capacity mix from the 2025 IRP Update. The plan emphasizes adding new dispatchable resources, reducing coal dependence, and increasing flexible peaking capacity through combustion turbines, batteries, and efficient combined-cycle units. By 2040, natural gas generation is expected to provide a larger share of energy production, while retaining the Cross Station maintains coal capacity as a strategic hedge against potential gas price volatility.

- Taylor Allred (Coastal Conservation League (CCL)) observed that the 71% reliance on natural gas in 2040 represents a significant exposure to fuel price volatility. They cautioned that while coal provides some hedge value today, its long-term viability could be limited by future environmental regulations and market disruptions, creating a potential risk from overdependence on a single fuel source.

Clay reviewed the short-term action plan outlined in the 2025 IRP Update. Key priorities include advancing the joint combined-cycle project with Dominion, coordinating with Central Electric on approvals and implementation of the Winyah LM6000 units, and completing the battery RFP process at the Jeffries site. Santee Cooper will also evaluate short-term power purchases to meet the emerging winter 2027 capacity need and continue collaboration with Central and developers on solar PPAs. Since filing the IRP update, one 42-MW solar PPA has been executed, marking tangible progress on the plan. Clay clarified that the newly executed 42-megawatt solar PPA was awarded through the CPRE process rather than as a qualified facility. In response to follow-up questions, he and David Millar (Director of Resource Planning, Santee Cooper) confirmed that the 42 MW represents the total project size, which is jointly shared with Central Electric.

- Findlay asked Clay to clarify a comment that he had missed about new solar projects. Clay explained that a 42-megawatt solar power purchase agreement had been signed after the filing of the 2025 IRP update and that it originated from the Competitive Procurement of Renewable Energy (CPRE) process, not a qualified facility.
- Eddy Moore (Southern Alliance for Clean Energy (SACE)) followed up, asking whether the 42 megawatts represented Santee Cooper's share or the total project capacity. David confirmed that 42 megawatts refers to the total project size, which is shared with Central Electric.

Clay outlined the next steps in Santee Cooper's planning process, emphasizing continued stakeholder engagement on the load forecast methodology, with a follow-up discussion planned for the April working group meeting. He said the team will coordinate with Central on developing updated load forecasts, track potential large new loads, and monitor environmental regulations. He also confirmed that several studies required under prior IRPs will be completed, including the Cross retirement transmission analysis, planning reserve margin, renewable integration, Demand Side Management (DSM) market potential, and wind feasibility studies. Stakeholders will be updated as these efforts move forward.

- Eddy asked how much of the projected new load through 2031-2032 is already contractually committed under the new tariff. David replied that none had signed yet, but several were progressing through technical studies and evaluations before committing to 15-year minimum-bill Energy Service Agreements (ESAs) that protect existing customers.
- Anna Sommer (Energy Futures Group on behalf of SACE and CCL) then asked about the maturity of these projects and whether Santee Cooper's interconnection procedures had evolved since earlier filings. David and Clay acknowledged that process improvements are underway in collaboration with Central, including updates to study procedures, but specific details would need follow-up.
- Anna pressed for stronger requirements on large-load applicants, such as providing validated dynamic load models and committing meaningful financial guarantees early in the process, to prevent speculative or risky projects from advancing. David agreed with the concept and said Santee Cooper is developing a structure with increasing financial commitments to ensure projects are genuine.
- Eddy asked whether the absence of signed customers under the new tariff also applied to cooperative loads. Clay confirmed that while a few hundred megawatts of agreements have been signed since the 2024 IRP update, none appear to be under the new tariff.
- Taylor asked whether major expansions of existing loads, such as Google's new data-center investments, would be subject to the same tariff and study process. David clarified that expansions are not grandfathered; they are subject to the same large-load tariff requirements.

Clay acknowledged the work already contributed to the 2025 IRP Update through multiple technical sessions and nine stakeholder meetings and expressed his appreciation for the SWG's continued engagement and time commitment. He then reviewed the procedural schedule for the IRP update, now filed under docket 2025-18-E: ORS will file its report by December 15, intervenors' comments are due January 12, 2026, and Santee Cooper will file reply comments January 26, 2026. Final order timelines will likely follow a similar pattern to prior years, and the schedule will continue to be revisited at future meetings.

Legislative Impacts on the IRP from Act 41
– Clay Settle, Manager, Resource Planning, Santee Cooper

Clay provided members with Santee Cooper's interpretation of Act 41 and its implications for Integrated Resource Planning. He explained that the Act's requirements apply specifically to triennial IRPs, beginning with the 2026 cycle. The utility is currently assessing how to integrate these provisions and will bring forward a detailed implementation approach in future stakeholder meetings.

He noted that Act 41 introduces new obligations around transmission planning and transparency, requiring utilities to incorporate updates to their Open Access Transmission Tariffs, describe planned transmission improvements tied to new resource siting, and explain how transmission constraints and investment alternatives are to be evaluated. Clay invited members to share feedback or alternative interpretations for Santee Cooper to consider as it develops its compliance approach.

- Taylor asked whether new Act 41 elements added in the 2026 triennial IRP would also need to be updated annually going forward. Clay said that would need further consideration.
- Eddy then suggested that Santee Cooper should not interpret the DSM language in the statute as excluding DSM review from IRP proceedings, and Clay agreed to revisit that idea internally.
- Anna shifted the discussion to Act 41's new balancing factors on economic development and affordability and questioned how affordability should be represented. She warned against using simple average-rate metrics that mask impacts on non-data-center classes, especially given

transmission cost allocation. Clay asked for examples, and Anna replied that the industry has not yet converged on a robust method. David noted that a solution is likely somewhere between a blunt average-rate approach and a full rate study.

- Maggie Shober (SACE) added that affordability analysis should also consider bill-spike risk, for example, via fuel-price assumptions. She proposed that ways to assess the risk of customer bills spiking under particular portfolios could be another way to examine affordability. Clay responded that these considerations will be evaluated and will return for discussion in upcoming IRP planning sessions.

Wind Study Update
– Clay Settle, Manager, Resource Planning, Santee Cooper
– Bob Davis, Executive Consultant, nFront

Clay provided members with an overview of Santee Cooper's upcoming wind study, explaining that DNV Energy Systems USA has been engaged to perform a feasibility assessment of onshore wind development in South Carolina, including within Santee Cooper's service territory. The study will evaluate project development timelines, benchmark capital and operating costs, and create refined wind production profiles specific to the region, which is an improvement over the generic NREL data used in past IRP analyses. Work began over the summer and is scheduled for completion by the end of November, with results and key findings to be shared at the next stakeholder meeting in February.

- Taylor asked whether the DNV wind study would consider leveraging in-state manufacturing capabilities, such as local companies already producing or transporting wind components, as a way to reduce costs. Clay responded that the current study is not examining specific suppliers or supply-chain advantages; its scope is limited to assessing feasibility and identifying potential onshore wind locations and production profiles for future IRP use. Taylor accepted the answer and suggested it could be considered in future scoping discussions.
- Anna asked what standard DNV would use to judge whether wind is "feasible," noting that simply being able to erect turbines and generate electricity is not in question, so she wanted to understand the actual benchmark being applied. Clay responded that, based on his understanding, the study is largely a geographic and siting feasibility screen, constrained by factors like airports, military bases, turbine-height limits, and residential setbacks, and it is intended to identify where wind could practically be located and to generate production profiles for IRP use. Anna restated that is essentially a land-exclusion and potential-capacity assessment, which Clay agreed was a fair characterization. Rahul Dembla (Chief Planning Officer, Santee Cooper) added that wind has shown up theoretically in past portfolios despite there being no current utility-scale wind in South Carolina, so this study is meant to test whether that theoretical potential maps to actual developable potential. Anna then proposed that the study should also consider distributed or non-traditional turbines, such as ducted lower-height units, which might be economic in the current cost environment. Clay acknowledged the suggestion and said they could raise it with DNV.
- Eddy asked whether the wind study was considering the cost of wheeling imported wind from regions like MISO, noting past examples where wheeling materially increased delivered cost. Clay replied that the current study is focused only on in-state wind and is not modeling wheeling, though off-system Power Purchase Agreements (PPAs) could be evaluated later as a separate resource alternative. Rahul added that wheeled wind would likely be more expensive given exit fees, multiple-jurisdiction wheeling charges, and the absence of merchant projects currently offered to Santee Cooper. Bob reinforced that past analyses during the 2023 IRP suggested that after accounting for congestion, losses, and wheeling across MISO and Southern, imported wind had difficulty competing with local wind options.

- Taylor raised a concern about the timing of the wind study, noting that results would be completed late in the year and then discussed with stakeholders only after the holidays. He asked whether there could be interim touchpoints to allow earlier input so feedback could meaningfully influence the 2026 IRP. Clay said they would consider it, but the current plan is to present results at the next scheduled meeting after completion, and he hesitated to add meetings during the holiday period. Taylor acknowledged the response and suggested a technical session at a later point if feasible.

2026 Reserve Margin and ELCC Update
– Joel Dison, Technical Manager, PowerGEM

Joel Dison provided members with preliminary findings from the updated reserve margin study conducted for Santee Cooper. The analysis focused on the year 2030 and incorporated 44 years of historical weather data from 1980 to 2023. The modeling included Santee Cooper, Southern Company, Duke Energy (Carolinas and Progress), and Dominion Energy South Carolina, using the 2024 IRP Update resource mix. This mix reflected existing generation, approximately 250 megawatts of energy storage, Central NSR PPAs, and about 1,700 megawatts of solar additions. PowerGEM used SERVM's stochastic Monte Carlo modeling framework, running more than 22 million hourly simulations to capture uncertainty in weather, long-term load forecast error, and unit availability. Neighboring utilities were set to a common reliability standard of 0.1 days per year LOLE to ensure the analysis reflected diversity benefits without relying on temporary surpluses from interconnected systems.

The updated study incorporated more recent load data from 2021 through 2023, which captured additional cold-weather years and revealed greater volatility in winter load response. Santee Cooper's LF-2501 load forecast was used as the base, with scaling adjustments that aligned the forecast to a 25-year weather-normal average, an approach that balanced Santee Cooper's 20-year method and Central's 30-year method. Unit outage assumptions were revised using the latest GADS data to better reflect actual operating performance.

A key methodological change involved the treatment of data center and other high-load-factor customers. These loads were modeled separately because they do not vary meaningfully with temperature or weather conditions. Isolating them from the underlying load data prevented artificial load variation in the simulations. Together, these refinements improved the accuracy of the reliability assessment and provided a more representative picture of Santee Cooper's system performance and risk exposure under the projected 2030.

Joel explained that the findings presented were preliminary and still under review by Santee Cooper. The base-case reserve margin was set at 20 percent, up slightly from the previous 18 percent, which is consistent with regional standards. The increase is attributed to stronger winter load response from updated historical data, revised unit-outage data from GADS, and small effects from changes in load-scaling methods.

He also described several sensitivity analyses. When modeled as an islanded system without regional diversity benefits, the reserve margin rose to 32%, showing the value of interconnection. Reducing solar additions by half made almost no difference, while doubling data center load lowered the reserve margin to about 19.5%, because these loads are less sensitive to weather and thus reduce system volatility. A case that reduced transmission imports by 50 % increased the reserve margin by only 0.5%, suggesting that transmission constraints would need to be much more severe before they materially affect reliability. Joel concluded that these tests represent the key analytical findings of the reserve margin study.

- Eddy asked how data center loads were modeled, specifically whether they rise in summer due to cooling or are treated as flat loads. Joel said Santee Cooper provided an 8760 hourly shape showing modest seasonal variation, with higher summer usage, and that this fixed shape is applied across all weather years since data center demand does not track weather volatility the way native load does. He went on to explain that although data centers operate at a high and fairly steady load year-round, they do increase somewhat in the summer due to cooling. Santee Cooper provided a single 8760 hourly profile for data centers that is applied across all weather years, so it does not rise or fall the way system load does in mild or extreme weather. He gave a simple example showing how system peaks can swing by a few hundred megawatts depending on the weather, whereas data centers do not follow that pattern, only showing modest month-to-month variation.

- Eddy then asked whether the planned merger of balancing authorities at Duke would affect results; Joel said it should not materially impact the study.
- Eddy pointed out that while the IRP assumes 1500 MW of solar (in 500-MW blocks), in reality, the projects coming online so far are smaller and below those initial blocks, which matters because data centers peak in summer when solar might under-deliver. Joel responded that this concern is valid and that they have included a scenario with lower solar penetration in their analysis.
- Taylor noted that because roughly 70% of Santee Cooper's energy is sold to Central, using a simple 50/50 split between the parties when scaling loads may not reflect the actual distribution of responsibility, and might warrant a different weighting. He also observed that across the country, more utilities are beginning to incorporate climate-change projections into reserve-margin studies, and although doing so would extend beyond the scope of the present analysis, it is something worth flagging for longer-term consideration as load forecasts and generation assumptions evolve. Clay said they'll pass the comments to the load-forecast team and discuss internally.

Joel reported preliminary results showing a base-case planning reserve margin of 20 percent, up from 18 percent, driven mainly by higher winter load response under updated historical data, GADS updates, and a minor effect from load-scaling changes. He walked through several sensitivities. Under an islanded scenario with only contracted purchases and no regional diversity benefit, the reserve margin rose to 32 percent. Cutting expected solar additions in half had a negligible effect. A high data center load sensitivity slightly lowered the reserve margin to about 19.5 percent because data center load reduces overall weather-related volatility in peak demand.

Joel indicated that they also tested reduced transmission import capability. Cutting imports by 50 percent increased the reserve margin by only about half a percent, suggesting that meaningful impacts would not occur until import capability dropped far below that threshold. Joel noted that these sensitivities capture the central effects observed in the study so far.

- Chelsea Hotaling (Energy Futures Group, on behalf of SACE and CCL) asked whether, in the scenario where data-center load is doubled, the model assumes adding extra supply resources, and if so, whether those added resources are assumed to be gas units or a mix of renewables and storage. Joel explained that in the base-case calibration, they didn't add resources; they removed some existing units to bring the LOLE to the 0.1 target (dropping capacity like Hilton Head, Myrtle Beach Unit 4, and partly derating Unit 3). When the doubled data-center load was applied, they again did not add resources; instead, they removed slightly less capacity than before, about 389 MW instead of 500 MW, which is what produced the ~19.4% reserve margin. In short, increased load plus a smaller removal of capacity yielded the new margin; no new gas or renewables were added in that sensitivity.
- Chelsea then asked a follow-up about the load-scaling method, seeking clarity on whether older load years were being dropped. Joel clarified that all 44 historical load shapes remain in the SERVM model, but a single scaling factor is applied to all years. That factor is derived such that the median of the most recent 25 years aligns with the current load forecast, rather than abandoning the older years entirely.
- Anna sought clarification on how it was possible that generators were being removed even when the data-center load was doubled. Joel explained that the preferred plan was already more reliable than the Loss of Load Expectation (LOLE) target, so the base case required removing 500 MW of capacity just to bring the system back to the 0.1 LOLE benchmark. In the high-data-center sensitivity, the added

load reduced the amount of removal needed to return to 0.1 LOLE, from 500 MW down to 389 MW, rather than requiring additions. In other words, a higher load absorbed some of the excess reliability margin that existed in the preferred plan. Clay restated the logic to confirm the treatment of load: the existing, historically embedded data center load was left in the base load, and only the forecasted incremental data center load was explicitly modeled in the study. The sensitivity doubled only Santee Cooper's incremental portion of that data-center load, not Central's, since part of Central's data-center load is already reflected in the historical baseline. Joel agreed with that description.

- Anna asked whether the team had examined whether removing units to reach the 0.1 LOLE target might change capacity factors on the remaining thermal fleet, especially marginal units, and whether that could increase forced outage risk, citing ERCOT experience post-Uri. Joel said they tried to minimize that effect when choosing which units to remove. They first removed units with very low historical utilization, such as the Hilton Head and Myrtle Beach oil Combustion Turbines (CTs), whose capacity factors would not materially change even with added data-center load. When additional reductions were still needed, they removed Winyah 4 because it was already considered marginal in prior planning work. He noted that this approach aimed to avoid pushing more heavily used units into significantly higher run-hours that could affect reliability.
- Anna followed up by asking whether the study evaluated whether any of the remaining units would see materially higher capacity factors as a result of the generator removals and higher data-center load, and whether that could translate into higher forced-outage rates and new reliability risks, particularly for units that have historically run at very low utilization. Joel acknowledged the question was valid and said they did not specifically analyze that effect, and suggested Santee Cooper could consider whether to examine it further.
- Eddy asked why generators would be removed in a high-load sensitivity when the objective is to set a reserve margin to ensure reliability, stating it seemed counterintuitive that removing capacity could make the system more reliable. Joel explained that the starting portfolio for 2030, based on Santee Cooper's existing IRP assumptions, was already more reliable than the 0.1 LOLE standard, indicating the system had more capacity than required to meet the reliability benchmark. To identify the reserve margin at the 0.1 threshold rather than at an over-reliable state, capacity must be removed until the model lands at the target reliability level. Clay clarified that the portfolio used was from the 2024 IRP update assumptions available at the time.
- Eddy observed that most capital investment and major retirements being contemplated will materialize in the early 2030s, so a reserve-margin analysis anchored only in 2030 may not reflect the reliability implications of that changed resource mix. He suggested evaluating a later year once construction and retirements are in effect. Clay responded that reserve-margin studies are intentionally anchored in relatively near-term years because they are meant to guide immediate reliability planning decisions, and they are re-run every triennial IRP cycle, rather than trying to lock in a far-future year with higher uncertainty. Joel added that 2030 was chosen because it aligns with the window in which the next binding decisions must be made, while longer-term years will still be evaluated through SERVM runs of full portfolios as part of the 2026 IRP, allowing future reliability effects to be captured without anchoring the reserve-margin selection on a distant and uncertain year.
- Taylor cautioned that data centers present challenges beyond simply adding high-load-factor megawatts to the forecast. He flagged uncertainty around both the scale and utilization of future data centers, the possibility of a speculative bubble, and several operational risks: sensitivity to voltage sag, potential for sudden tripping to backup generation, harmonic distortion from AI electronics, and unpredictable ramping behavior not tied to weather-driven patterns. He warned that as data centers become a larger portion of total load, these characteristics could create cascading reliability and

power-quality issues. Joel responded by clarifying that the study only models contracted data-center load, not speculative amounts. Clay acknowledged the points and said they should be relayed to the load-forecasting team for consideration in how potential data-center load is treated going forward. He also noted that the sensitivity in this study was narrowly focused on reserve-margin impacts, not the broader operational consequences Taylor described. Joel added that much of what Taylor raised relates to power quality and system operations rather than resource adequacy, and Stewart suggested those issues would need to be addressed at a later stage.

- Chelsea asked whether energy efficiency impacts and electric vehicle load were handled separately in the model, the way data centers were. Joel replied that the load forecast already reflects energy efficiency as a net reduction, so it was not modeled separately. Electric vehicle charging, however, was given its own load shape and treated separately in the same manner as the incremental data-center load.

2026 Integration Study Overview

– Joel Dison, Technical Manager, PowerGEM

Joel Dison concluded his presentation by outlining the next phase of PowerGEM's work with Santee Cooper—the solar integration study. Beginning in November and continuing through the first quarter of next year, this study will examine the level of operating reserves required to integrate solar generation into the Santee Cooper system. It will analyze short-term, five-minute dispatch intervals to assess how solar variability affects the system's ability to maintain balance and reliability.

The approach involves first modeling a five-minute base case without solar to establish a baseline of "flexibility violations," or moments when the system cannot respond quickly enough to load changes. Solar resources will then be added in stages, and any increase in flexibility violations will reveal the additional reserves needed to preserve system reliability. The study will not assign monetary values but will quantify the operational reserve requirements at different levels of solar penetration for use in Santee Cooper's future planning.

- Anna questioned whether PowerGEM's plan, to remove renewables and recalibrate the system to a 0.1 LOLE standard, might create an unrealistic starting point, one tighter than what actually exists on Santee Cooper's system. The exchange centered on how to define the "base case" for the upcoming solar integration study. She argued that the study should use the real-world operating condition, which already functions reliably under NERC's standards, and measure any increase in flexibility violations from that point rather than from an artificial "perfect" baseline. Joel and Clay acknowledged her concern. Joel clarified that the 0.1 calibration was only to ensure the system was capacity-reliable before testing intra-hour flexibility, not to eliminate violations entirely. He agreed it might make sense to consider today's actual operating conditions – where Santee Cooper has about 200 MW of solar – as an additional or alternative base case. Clay supported reviewing current ACE deviation data to inform that choice. The discussion ended with Joel agreeing to follow up internally to explore the feasibility of Anna's suggestion before finalizing the study design.
- Eddy asked whether the 300 megawatts of batteries slated for 2029 were included in the upcoming integration study. Joel Dison explained that this would be determined in consultation with Clay Settle when finalizing the study's assumptions. Including batteries would increase system flexibility, but whether to model them depends on whether the goal is to measure flexibility with or without those added reserves. He recommended excluding them to isolate the solar-related impacts, while noting that Santee Cooper might choose to include them.
- Eddy then asked about other generation changes. Clay replied that this was still under review, as the resource mix had evolved between the 2024 and 2025 IRP Updates, rising from 240 to 300 megawatts

of batteries and adding the Winyah LM6000 CTs. He confirmed that both the Santee Cooper and Co-op battery projects in Central are reflected in the IRP, totaling 240 megawatts in the prior reserve margin study, and that the team will revisit these assumptions to determine the most accurate portfolio for the integration analysis.

Meeting Closeout
– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart and Clay expressed their appreciation for the involvement, participation, and contribution of the Stakeholder Working Group members in this meeting.

Commitments and Next Steps

ACTION ITEM – noted during the meeting discussion	By **WHOM**
1. Discuss Act 41 IRP impacts and plans to incorporate in future SWG meetings	Resource Planning
2. Provide background information on large load risks from other jurisdictions	Anna Summer
3. Consider the review of duct turbine generators as part of the Wind Study	Resource Planning
4. Consider internally an increase in the opportunity for input/feedback into the Wind Study	Resource Planning
5. Confirm the wind hub heights that are being studied	Resource Planning
6. Discuss with the load forecast team the potential impact considerations of data center load discussed in today's meeting	Resource Planning
7. Resource Planning will discuss internally the level of "flexibility violations" seen currently	Resource Planning
8. Provide information on consumer affordability	Anna Summer
9. Provide additional information comments on Act 41	Taylor Allred

Next Steps:

- The next Working Group meeting is scheduled for February 2026
- The next general notice meeting will be on November 18, 2025
- Members wishing to present a topic at a future meeting may contact Ellie Gallagher or Clay Settle

APPENDIX A

List of Stakeholder Working Group Members and Attendees

ORGANIZATION	**MEMBER /** ALTERNATE	September 10th ATTENDEES
Office of Regulatory Staff	Findlay Salter Jeffery Gordon Julian McElhaney **Shane Hyatt**	Findlay Salter Jeffrey Gordon Julian McElhaney Shane Hyatt
SC Dept of Consumer Affairs	**Jake Edwards** Roger Hall	
SC Dept of Natural Resources	Elizabeth Miller **Lorianne Riggin**	
SC Dept of Environmental Services	**Rhonda Thompson** Robert Brown	Robert Brown
Central	**Caleb Bryant** Leslie Maley	
J. Pollock	Jeffry C. Pollock **Jonathan Ly**	
Century Aluminum	**Michael Early** **Stephen Thomas**	Stephen Thomas
Nucor	**Bradley Powell** Karl Winkler	
Messer	**Michael Peters** Steven Castracane	
Google	**Katie Ottenweller** Will Cleveland	
SC Association of Municipal Power Systems	**Adam Hedden** Eric Budds	
Individual	**Charles Hucks**	
Individual	**Richard Berry**	
Individual	**Diane Bell**	Diane Bell
Individual	**Dennis Boyd**	Dennis Boyd
Carolinas Clean Energy Business Association	Hamilton Davis **John Burns**	
Conservation Voters of South Carolina	Erin Siebert **Jalen Brooks-Knepfle** John Brooker	
Coastal Conservation League	Kennedy Bennett **Taylor Allred**	Taylor Allred
Energy Justice Coalition	Shayne Kinloch	
South Carolina Appleseed Legal Justice Center	**Sue Berkowitz**	
South Carolina Research Authority	**Greg Wilcox**	
Southern Alliance for Clean Energy	**Eddy Moore** **Maggie Shober**	Eddy Moore Maggie Shober

Southern Environmental Law Center	Anna Sommer Chelsea Hotaling **Kate Mixson** Nina Peluso Thomas Gooding	Anna Sommer Chelsea Hotaling
Sierra Club	**David Rogers** Dori Jaffe Mikaela Curry Sari Amiel	
Vote Solar	**Jake Duncan**	
Santee Cooper Resource Planning	**Clay Settle** David Millar Rahul Dembla **Ellie Galagher**	Clay Settle David Millar Rahul Dembla Ellie Galagher
PowerGen		Joel Dison
nFront Consulting	**Bob Davis** Jonathan Nunes	Bob Davis Jonathan Nunes
Vanry Associates	Peter Claghorn **Stewart Ramsay** Yvette Smith	Peter Claghorn Stewart Ramsay Yvette Smith

**Members listed in alpha order by first name*

Also in Attendance

Office of the Regulatory Staff		Shawn McGlothlin
		gskipper
		Dylan