

Santee Cooper IRP Stakeholder Process 2024-2026

Stakeholder Working Group Meeting #10 – Meeting Summary

Date: April 9, 2026

Time: 10:00 am – 2:38 pm EDT

Location: Virtual Meeting via Zoom, Vanry Associates facilitating

Meeting: Santee Cooper Stakeholder Working Group Session #10

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 & April 9th Meeting Attendees

Meeting Information & Materials

The Santee Cooper Resource Planning team held its tenth IRP Stakeholder Working Group meeting on April 9, 2026. The IRP Stakeholder Working Group is integral to Santee Cooper's commitment to engage stakeholders in its ongoing integrated resource planning process. The meeting covered Santee Cooper's 2026 Load Forecast, Wind Feasibility Study, and several other study results, including the 2026 Reserve Margin, Effective Load Carrying Capability (ELCC), Integration and Energy Efficiency (EE) and Demand Side Management (DSM) Market Potential. Also discussed were the 2025 IRP Update and next steps related to the 2026 Triennial IRP filing.

The presentation shared during the meeting is available in the Stakeholder Working Group section of the [Santee Cooper 2024-2026 IRP Stakeholder Process webpage](#), along with materials from the previous nine working group meetings and other related sessions.

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.

A total of 21 working group members and their colleagues attended the meeting, as well as 13 of the Santee Cooper team, including supporting consultants. Appendix A lists the organizations represented and individuals who attended the April 9th meeting.

Topics, Presenters, and Discussion

The presentation, which included the meeting agenda and associated timing of the various conversations, was emailed to members on April 2, 2026.

Welcome and Agenda

– *Stewart Ramsay, Meeting Facilitator, Vanry Associates*

Stewart Ramsay opened by welcoming attendees and noting that Clay Settle and Will Brown had been promoted, with Will now accountable for the Resource Planning team. He introduced the day's speakers: Carl Ciullo (Santee Cooper Financial Analyst, returning presenter), Daniel Pardo (DNV project manager, new to the group), Joel Dyson (Power Gem, returning), and Stephen Roys (Santee Cooper, Manager of Program Development, returning).

Working Group Business

– *Will Brown, Manager Resource Planning, Santee Cooper*

Will Brown began by reviewing the list of actions identified in prior sessions. He noted most would be discussed during the meeting and specifically addressed the first item on the impact of Act 41 on the upcoming 2026 IRP. He noted the resource planning team concluded, after a thorough review of the legislation and changes to the IRP statute (§58-37-40), that the only material change is section B1j, requiring that a transmission report be filed alongside the IRP.

Will then walked through the roadmap of upcoming meetings: today's session covering supporting studies and a preview of proposed changes to assumptions, methodologies, and portfolios; an April 30 Coal Retirement Technical Meeting; a June 3 session to finalize IRP assumptions; and a June 11 General Notice public meeting, all leading to the September 30th IRP filing with the Public Service Commission (PSC).

He reminded members that the 2026 filing is for Santee Cooper's triennial IRP, meaning it will be a fully litigated proceeding with testimony and a PSC hearing anticipated in April/May 2027. Resource Planning will present the IRP to the Santee Cooper Board of Directors on September 29, one day before filing with the PSC, and expects to schedule Meeting 12 with the working group sometime mid-October. A data room with Encompass inputs, outputs, and modeling results will open one to two weeks after filing, with NDAs available for signing in August for those requiring access.

2026 Load Forecast Update

– *Carl Ciullo, Financial Analyst, Santee Cooper*

Carl Ciullo opened by orienting the group on where the load forecast stands in its development cycle. With no feedback on the 2025 Load Forecast update at the December General Notice meeting, the Resource Planning team proceeded with modest changes to the methodology. The forecast is on track to be finalized in mid-May and handed off to generation planning. The overall methodology remains largely consistent with prior IRP forecasts, with the most notable changes in the EV and rooftop solar segments. Updates to assumptions were warranted based on the forecast results for the residential, commercial, industrial, Central member cooperative, and potential new large load, while no significant methodology changes were needed.

For the residential and commercial segment, several noteworthy developments are shaping the forecast. Customer growth in Horry County remains steady at roughly 5,000 new customers annually, consistent with post-2020 trends. Santee Cooper's April 2024 rollout of a new demand-based residential rate structure produced a strong customer response expected to reduce peak demand, and the team is evaluating how best to incorporate that effect into the model. On the all-electric home front, the team had previously assumed the ~30% share of new all-electric homes would hold long-term, but a South Carolina Supreme Court ruling easing regulatory constraints on Dominion's natural gas distribution expansion is now expected to erode that share over the coming years, representing a meaningful change from the prior forecast outlook.

The notable changes in results stem from the electric vehicle (EV) and rooftop solar forecasts, both of which are shifting from national third-party benchmarks to Santee Cooper-specific data derived from the utility's smart meter infrastructure. For EVs, actual customer usage is coming in well below the prior 5.3 MWh/year

assumption, meaning less energy attributed to EVs overall; with notably higher morning charging activity around 8:00 AM, which will increase peak demand pressure, particularly in winter. Encouragingly, Santee Cooper's super off-peak rate incentives are driving significant overnight charging, reducing afternoon peak impacts. The rooftop solar forecast is undergoing a similar shift to customer-specific load shapes. Changes there are expected to be modest relative to prior forecasts, with end-of-period demand impact remaining in the range of roughly 7 MW.

- Jake Duncan (Vote Solar) asked whether Santee Cooper had assessed current and forecasted PV paired with storage, and whether PV-plus-storage load shapes were modelled separately from standalone PV. Carl explained that in prior IRPs, a high rooftop solar scenario was incorporated into the low load forecast case and included optimally dispatched battery storage to minimize system demand. For the 2026 IRP, the team is still working through the storage treatment. The likely approach is that, because the forecast is now built from actual Santee Cooper customer smart meter data, any customer-sited storage will already be embedded in the observed load shapes, and importantly, will reflect how customers actually dispatch their batteries rather than an assumed optimal dispatch strategy.
- Jonathan Ly (J. Pollock, Inc.) acknowledged Carl's response but offered a suggestion: while historical smart meter data may adequately capture the current modest level of customer-sited storage, he encouraged the team to think carefully about how that picture could change as storage adoption grows. His concern is that a historically grounded load shape may not accurately reflect forward-looking trends, given the broader national trajectory of customers increasingly pairing rooftop solar with storage and potentially dispatching it in ways that differ meaningfully from current observed behavior.

Carl continued to review the potential new large loads segment, providing context on the methodology introduced in the 2024 IRP. This post-modelling adjustment captures risk-adjusted load from customers who have expressed interest in receiving service from Santee Cooper or its member cooperatives but have not yet signed contracts, thereby distinguishing it from the industrial load forecast, which, by definition, includes only contracted customers. Carl noted that roughly half of the 1,100 MW originally forecasted to materialize over 15 years has already done so, which the team views as a positive validation of the methodology. He cautioned, however, that the preliminary 2026 IRP figure should not be taken as final, as the assumptions are still being refined.

Carl walked through the funnel-style risk adjustment process. Of approximately 5,300 MW of total identified interest, the team, drawing on expertise from transmission planning, economic development, industrial services, and other groups, narrowed the field to projects considered reasonably likely to connect, arriving at roughly 3,600 MW input for the stochastic model. Each project is then assigned probabilities for contract size and ramp-up timeline. The 50th percentile outcome of that model yields a risk-adjusted planning load of approximately 1,100 MW, which is further reduced to reflect that not all contracted load will be on-peak at the time of the coincident peak. Carl also noted that non-firm service inquiries from several customers are being tracked and will be incorporated into the model if those discussions mature.

He closed by reminding the working group that the load forecast is in its final month of development, with a mid-May handoff to generation planning. Any stakeholder feedback on methodology or assumptions needs to be submitted as soon as possible, ideally within the week, to allow time for review and incorporation. The team plans to present the final load forecast results at the June working group meeting, with high and low-case scenarios to be developed after that.

Wind Study Results

– Daniel Pardo, Project Manager, DNV

– Will Brown, Manager Resource Planning, Santee Cooper

Daniel Pardo presented the findings from a wind energy feasibility study commissioned by Santee Cooper, followed by comments from Will regarding next steps. The feasibility study covered four areas: wind resource potential across South Carolina, the development process and timeline, capital and operating cost estimates, and energy production estimates for two theoretical projects. To identify viable sites, DNV applied a multi-criteria screening process across the entire state, filtering for proximity to Santee Cooper's transmission system, minimum wind speeds of 5 m/s at 115-meter hub height, terrain slope under 15%, minimum site capacity of 50 MW, and exclusion of wetlands, flood zones, urban setbacks, and counties with wind ordinances. The process yielded 41 potential sites with an average capacity of 150-190 MW and wind speeds ranging from 5.4 to 6.2 m/s. Each site was scored across multiple attributes, including proximity to transmission lines, hurricane risk, wildlife management areas, and military airspace, using a flexible weighting system that Santee Cooper can adjust to reflect its own development priorities.

On costs, DNV provided both capital expenditure (CapEx) and operating expenditure (OpEx) estimates. Current CapEx for a South Carolina wind project is approximately \$2,200/kW, broken down across the turbine supply agreement (the largest component), balance of plant, and development/permitting costs. That figure is expected to decline by roughly \$200/kW by 2034-2035, aligning with Santee Cooper's IRP development timeline. On the OpEx side, total average annual costs over a 20-year operating life are estimated at approximately \$39,000/MW per year, with unscheduled maintenance representing the largest cost component. A typical project development timeline runs two to four years, with construction requiring an additional one and a half to two years.

For the energy production analysis, DNV selected two of the 41 identified sites, designated EFD1 and HRY2, and modeled two turbine configurations, each resulting in a 55 MW project. Net annual energy estimates ranged from 112 to 147 GWh depending on site and turbine selection, with capacity factors varying accordingly. Seasonally, peak production is expected between February and April, with the lowest output occurring June through August; a profile that is generally complementary to summer peak demand but worth noting in the context of resource adequacy planning.

- Chelsea Hotaling (Energy Futures Group on behalf of SACE and CCL) asked whether the 41 identified sites and their aggregate capacity represented a total technical feasibility ceiling; would the study translate into a cumulative build limit applied during IRP modeling? Will clarified that the study is not intended to be used that way. While development rate constraints like those applied to solar would likely factor into modeling, Santee Cooper does not plan to extrapolate a maximum onshore wind installation cap for South Carolina from this study.
- Taylor Allred (Coastal Conservation League (CCL)) asked about the process and investment required to collect site-specific wind speed data, and whether existing public data sources might reduce that burden. Will explained that the critical variable is wind speed at hub height, typically around 115 meters, which cannot be reliably sourced from general weather service data alone. The practical path forward requires on-site measurement using LiDAR or SODAR equipment deployed for approximately one to two years. While DNV's proprietary wind mapping tools, drawing on NOAA, NASA, and other public sources, can serve as an effective prospecting tool to identify promising sites, that data is not sufficient on its own to support project development, secure financing, or accurately forecast production and revenue.

Daniel noted that modern wind resource maps have improved substantially and provide a strong foundation for initial site screening, but on-site measurement remains essential for turbine selection. Beyond average

wind speed, two variables, turbulence intensity and extreme wind speed, cannot be reliably estimated remotely; both must be measured on site, as they are critical inputs for identifying the appropriate turbine class and subclass for a given location. Will added that local site conditions meaningfully affect production profiles even in relatively flat terrain like South Carolina, with coastal versus inland location being a significant differentiating factor; the study assumed 115-meter hub heights, above the current U.S. installed average of roughly 90 to 100 meters. On timing, Will noted that site data collection would be initiated when onshore wind appears as a selected resource within the IRP development window, and that any wind procurement would need to flow through Santee Cooper's competitive renewable energy procurement process, as required under South Carolina statute.

2026 Reserve Margin and ELCC Results

– Joel Dison, Project Lead, PowerGEM

Joel Dison presented the methodology underpinning the reserve margin study, which uses 2030 as the study year to inform near-term resource decisions. The analysis models 44 historical weather years spanning 1980 to 2023, applying those weather patterns to estimate what 2030 loads would look like under each scenario. Rather than modeling Santee Cooper in isolation, the study incorporates its immediate neighbors, including Southern Company, Duke Energy Carolinas, Duke Energy Progress, and Dominion Energy, to capture regional interdependencies. The starting resource mix was drawn from the 2024 IRP update, which included existing Santee Cooper resources plus 240 MW of battery storage, 672 MW of central PPAs, and approximately 1,500 MW of additional solar. The core reliability target is a loss-of-load frequency of no more than once every ten years, with a minimum of 100 MW of continuously maintained regulating reserves.

The probabilistic framework combines weather uncertainty with load forecast uncertainty and unit outage variability. Five load forecast error scenarios, ranging from plus or minus 4% to zero error, are combined with the 44 weather scenarios to produce 220 load scenarios, each weighted by probability. Approximately 100-unit outage draws per load scenario are then run on a Monte Carlo basis, resulting in thousands of 8,760-hour annual simulations. Several methodology updates were incorporated in this study cycle. Load shapes were retrained to include additional years through 2023, capturing recent cold weather events. The weather normalization baseline was updated from a 44-year average to a 25-year basis, splitting the difference between Santee Cooper's 20-year and Central's 30-year weather normal conventions. Non-conforming loads, such as data centers and other high load factor customers, were extracted and modeled separately to prevent them from being artificially scaled up and down with weather volatility.

The resource mix modeled reflects Santee Cooper's current predominantly thermal fleet, with coal representing the largest capacity share, followed by combined cycle generation and solar. A notable change from the prior study is an increase of approximately 142 MW of non-firm load in the base forecast, which Joel flagged as having a meaningful impact on battery ELCC results. Joel paused at this point to invite questions before proceeding to present study results.

- Taylor asked whether the separate treatment of data center loads adequately captured the seasonal variation in cooling load, noting that data center electricity consumption can run meaningfully higher in summer due to heat-driven cooling demand. Joel confirmed that seasonal variation is indeed incorporated into the data center load shapes, with summer loads represented as higher than the rest of the year. He clarified that the rationale for modeling data centers separately was not to flatten their seasonal profile, but rather to prevent them from being scaled up and down in response to year-over-year weather volatility in the same way that weather-sensitive loads are. Unlike residential and commercial loads, data center demand does not swing dramatically between a cold year and a mild year, and the separate treatment ensures that dynamic is accurately reflected in the simulations.

- Shelley Robbins (Southern Environmental Law Centre (SELC)) asked for clarification on the 1,259 MW combined cycle figure used in the study. Will explained that it comprises three units: the Cherokee facility, a recently acquired asset of approximately 100 MW, and two combined cycle units at the Rainey plant. He noted that one of the existing combustion turbines (CT) at Rainey is being converted to a combined cycle (CC) configuration, which results in a decrease in CT capacity but a corresponding increase in CC capacity on the resource sheet. Joel added that the figures reflect winter up-rated capacities. Will offered to follow up with Rainey CC figures.

2026 Integration Study Update

– Joel Dison, Project Lead, PowerGEM

Joel also provided a methodology update on the integration study, noting that results are still being vetted internally and are not yet ready for publication. The study's objective is to determine the operating reserves needed to integrate intermittent resources and loads, measured by the system's ability to meet the North American Electric Reliability Corporation (NERC) Control Performance Standard 1 (CPS1) requirements; the standard governing a Balancing Authority's ability to maintain frequency within acceptable bounds over time. The traditional analytical approach used in prior studies measures flexibility violations, defined as five-minute inabilities to meet load due to ramping limitations, expressed in days per year. A reference case with no solar or batteries establishes a benchmark, tranches of solar are then added to stress the system, and load-following reserves are added until flex violations return to the benchmark level.

For this study cycle, the team identified a fundamental limitation of the traditional flex violation metric: the modeling environment cannot replicate real-time CPS1 conditions, including interconnection frequency response, creating a persistent gap between modeled and real-world results. To address this, PowerGEM developed a new metric called the CPS1 Stress Index, derived by substituting the modeled five-minute average megawatt imbalance for the frequency deviation term in the CPS1 compliance factor formula. While not a precise replication of CPS1, the index is directly proportional to the CPS1 compliance factor, making it a valid comparative metric across scenarios. The approach was developed in collaboration with experts at another utility and is believed to be a methodological improvement over flex violations alone.

To ensure transparency and allow Santee Cooper to evaluate the new approach, the study will report results using three parallel metrics: traditional flex violation days per year, total annual flex violations, and the new CPS1 Stress Index. All three will be benchmarked against a no-solar, no-battery 2030 reference case calibrated to 2021 operating reserve levels, the most recent historical period representative of a system without significant solar or battery penetration. Results will be reported as incremental realized operating reserves above that baseline. Batteries will be evaluated as a source of additional operating reserves where solar penetration causes metrics to exceed the benchmark. Joel indicated the team expects to finalize and share results with Santee Cooper shortly.

- Chelsea asked whether the integration study results would be translated into a \$/MWh integration cost applied in the capacity expansion model, as was done in prior IRPs, or whether the approach would shift to a portfolio-level treatment. Will and Bob Davis (nFront Consulting) explained that the intent is to move away from the static integration cost methodology used in the 2023 IRP and 2024, 2025 IRP Updates. Previously, an integration cost adder for solar and wind was applied only during portfolio optimization and then switched off during production cost modeling; a limitation driven by the absence of a good representation of incremental operating reserves. The new approach would use the integration study results to dynamically model operating reserves within Encompass, adding reserve quantities that scale with solar and wind penetration and applying them consistently across both portfolio optimization and production cost runs, effectively replacing the integration cost adder altogether.

Bob cautioned that while Encompass has demonstrated the ability to handle dynamic reserves in preliminary testing, the team is still awaiting final results from Joel before formally committing to the methodology change. Will added that Joel will present the integration study results at the June working group meeting, at which point the team will be able to speak definitively about how those results will be applied in IRP modeling.

- Chelsea also asked how five-minute resolution modeling is handled for renewable resources, specifically whether a distinct five-minute shape is used or whether the hourly profile is simply interpolated, and whether wind is modeled at that granularity given the data concerns raised during the ELCC discussion. Joel explained that for solar, the starting point is a set of 8,760 hourly profiles, one for each of the 44 historical weather years, capturing how solar output would differ under varying weather conditions. These hourly profiles are first converted into a smooth five-minute shape, and then volatility parameters derived from actual five-minute historical data obtained from a neighboring utility with significantly higher solar penetration are applied stochastically to introduce realistic sub-hourly variability. The result is a five-minute solar profile that reflects both the underlying weather-driven hourly shape and real-world volatility patterns. Wind, however, was not modeled at five-minute resolution, as the team does not have access to an appropriate dataset to support that level of granularity.

Market Potential Study Results

– *Steven Roys, Manager Program Development, Santee Cooper*

Steven Roys presented the results of the 2026 Market Potential Study (MPS) for demand side management (DSM), covering both energy efficiency and demand response. He framed DSM as encompassing two distinct activities: energy efficiency, which reduces overall electricity consumption through the installation of higher-efficiency equipment, and demand response, which shifts load away from peak periods without necessarily reducing total energy use. Market potential studies are conducted to identify cost-effective DSM opportunities, respond to customer interest in program participation, and satisfy a South Carolina statutory requirement to develop low, medium, and high potential scenarios. Steven noted that the study process involved three technical working sessions with stakeholders, during which measure lists were refined based on feedback, with some measures added, modified, or removed. The team's approach was to ensure correct inputs on the front end rather than targeting a predetermined savings level, allowing results to reflect what the data supports.

The study evaluated potential across a technical-to-achievable cascade, filtering from theoretical maximum through economic viability and market barriers to arrive at realistic adoption estimates. Three scenarios were developed using different incentive levels and cost-effectiveness thresholds. The low scenario used 30% incentives on incremental equipment costs with a utility cost test (UCT) threshold of 1.0. The medium scenario increased incentives to 50% and lowered the UCT threshold to 0.7 to allow portfolio-level cost-effectiveness screening. The high scenario used 75% incentives and assumed a 50% increase in avoided marginal energy costs, representing a stress case rather than a base expectation. Twenty-year cumulative achievable energy efficiency savings, accounting for measure useful life roll-off, were projected at 5% of 2026 base load in the low scenario, 7% in the medium, and 10% in the high. On a residential end-use basis, HVAC equipment dominates the potential, comprising more than half of the savings between space heating and cooling. Residential domestic hot water, previously a top-tier measure, has declined significantly due to an upcoming Department of Energy (DOE) baseline change in 2029 that will require heat pump water heaters as the standard, effectively raising the floor and reducing incremental savings potential. On the commercial side, interior lighting remains the largest opportunity, followed by lighting controls, space cooling, refrigeration, and ventilation. Annual savings are projected to ramp up through approximately 2029 before leveling off, reflecting

the natural saturation dynamic of efficiency markets as equipment becomes progressively harder to improve cost-effectively.

Demand response (DR) scenarios were structured around program mix and customer segment targeting. The low scenario represents a business-as-usual path, aligned with existing programs including the recently launched residential smart thermostat DR program, with a potential extension to small and medium commercial customers. The medium scenario included all economically viable loads and measures, targeting a curated mix of programs such as peak time rebates and critical peak pricing, designed to capture overlapping customer segments efficiently rather than running redundant offerings. The high scenario included all cost-effective customer segments regardless of program overlap, representing a maximum achievable ceiling. Residential customers dominate DR potential, with projected winter demand response savings growing from approximately 34 MW in the near term to 93 MW long term in the medium scenario, compared to less than 10 MW for each commercial segment. Unlike energy efficiency savings, which plateau over time, DR savings are expected to be more cumulative, as enrolled customers are anticipated to remain on programs with manageable comfort impacts and ongoing incentives, while new enrollments continue to grow the base.

Steven closed by noting that the MPS is not simply an IRP input exercise. Following the 2023 IRP MPS, Santee Cooper spent 2024 on program potential planning and in 2025 launched three new DSM programs, the first time in over a decade that three programs were launched in a single year. This underscores that the study process directly informs real program development and customer-facing implementation.

- Stewart asked whether the shift from resistive to heat pump water heaters under the upcoming federal Department of Energy (DOE) baseline change had been evaluated for its impact on demand response potential, noting that grid-enabled water heaters are used by some utilities as thermal storage assets, a capability that is significantly more difficult to replicate with heat pump water heaters due to their compressor-based operation. Steven and Jim Herndon (Resource Innovations) responded that water heater demand response, while included in the study, represents a relatively modest share of overall DR potential compared to thermostats and peak time rebate programs. The DR modeling for water heaters assumed either a switched resistive unit or a grid-enabled water heater, with the grid-enabled assumption already aligned with the natural customer transition to heat pump water heaters at end of useful life. The consensus was that the DOE baseline change would have a small but not significant impact on total DR potential, given that water heater DR was already a second-tier opportunity in the portfolio.

2025 IRP Update

– Will Brown, Manager Resource Planning, Santee Cooper

Will briefly noted that the final PSC order for the 2025 IRP update was received on March 5th, and that links to both the docket and the order were included in the meeting materials. The ordering paragraphs were presented verbatim in the slides without detailed review, and Will confirmed that Santee Cooper plans to comply with all ordering paragraphs, noting that some are already being addressed in the current meeting.

2026 Triennial IRP

– Will Brown, Manager Resource Planning, Santee Cooper

Will indicated that, upon review, a full assumptions presentation is planned for June, where staff will walk through everything being considered for change relative to the 2023 IRP and the intervening updates, noting that a triennial IRP carries different requirements than an update. The intent is to give stakeholders visibility into the thinking early enough to provide feedback before final outputs are presented. Anything not listed should be assumed to carry forward from the 2025 update or 2023 IRP. Regarding thermal resources, the

team is leaning toward excluding a 2X1 Natural Gas fired Combined Cycle Gas Turbine (NGCC) as an option, citing two reliability concerns: it would become the system's largest single contingency from a forced-outage and reserves-planning perspective, and its size would complicate scheduling of planned maintenance during off-peak months.

- Shelley raised two related questions about combined cycle (CC) resource modeling. First, she asked about the number of CC unit sizes being considered, and Will confirmed that, rather than three 1x1 NGCC configurations, the 2026 IRP will include a 1x1 and a 2x1 combined-cycle option to capture economies of scale.

Second, she asked how Santee Cooper is accounting for the significantly higher cost of firm gas transportation, given recent precedent agreements and market developments. Will and Bob explained that all overnight capital and O&M costs are being refreshed for the 2026 IRP, and that a FT reservation charge will continue to be modeled for any new combined cycle addition. The assumed FT charge is based on the precedent agreements executed for the Canadys combined cycle project, which incorporated multiple pipeline expansions as well as a new in-state pipeline with capacity well in excess of what the Canadys project alone requires. Bob noted that the team believes this assumption is conservatively high and representative of what could be obtained in today's market, and that the team considered going lower but opted to maintain a conservative posture.

- Shelley followed up by asking why a Transco Appalachian Basin access path had not been evaluated, given Transco's stated compression expansion capability. Bob acknowledged it as a valid alternative but explained that after evaluating multiple supply directions over several years, the team has not found a meaningful cost advantage from any single path, with firm transportation costs tending to converge in a similar range regardless of direction. Will added that the IRP is intentionally kept generic in nature, serving as a resource screening tool rather than a site-specific procurement plan, and that actual gas sourcing and siting decisions would be addressed through the appropriate regulatory and procurement processes.
- Jonathan asked how the assumed 2x1 combined cycle unit size compares to Santee Cooper's current single largest contingency, and whether the resource might be modeled as a sensitivity rather than a standard option. Will noted that Santee Cooper's single largest contingency is approximately 600 MW, while an advanced class 2x1 combined cycle would come in somewhere around 1,200 to 1,300 MW; roughly doubling the system's largest contingency event. Bob added that while a 2x1 configuration is being considered by larger neighbors such as Duke Energy, it fits their systems better, given their relative size. Dominion, which is roughly comparable in size to Santee Cooper, is also not considering a 2x1 in its IRP, underscoring that the unit size would represent a significant contingency management challenge for Santee Cooper specifically. Will indicated the team would capture consideration of a sensitivity run as an action item. Bob further noted that both the 2x1 and 3x1 configurations carry slightly lower dollar-per-kW costs than a standard 1x1, meaning the current modeling approach is conservatively high with respect to combined cycle and combustion turbine costs.
- Chelsea asked whether removing the larger multi-unit CC configurations would result in more 1x1 units being modeled, or whether build limits would change. Will clarified that the intent is to offer two CC resource options: a single 1x1 advanced class unit and a two 1x1 advanced class configuration, providing a modest step-up in project scale without the contingency concerns of a true 2x1. Bob noted that a true 2x1 has never actually been filed as a selectable resource in a Santee Cooper IRP, and that no hard build limits on combined cycles have historically been applied. He added that Santee Cooper's relatively modest long-term load growth naturally constrains the number of combined cycles the system can support, particularly beyond the mid-2030s, making the question of build limits largely academic given the load trajectory.

Will highlighted several assumption updates under consideration for the 2026 IRP. The wind production profile will be updated using the new South Carolina-specific data from the DNV study, replacing the outdated SAM model profiles. On the storage side, two changes are being evaluated: applying the energy community tax credit of 10% through 2035 for battery energy storage options and including a long-duration energy storage resource option in the IRP for the first time.

- Shelley asked for clarification on what "long-duration" means in this context, noting that four and eight-hour batteries are already included as standard options. Will and Bob confirmed they are referring to resources well beyond eight hours, likely in the 100-hour range. Bob acknowledged significant uncertainty around round-trip efficiency, currently estimated at 30 to 50%, and noted that the resource would not be justified on energy arbitrage economics alone, but could potentially pencil out as a capacity resource depending on further evaluation.

Will went on to explain that while Santee Cooper has been monitoring hydrogen developments, the team does not have access to a reliable long-term hydrogen fuel price forecast and therefore will not model hydrogen as an alternative fuel in the 2026 IRP. The team will continue tracking developments through its R&D group and at the federal level. Bob added that the GE H-class combustion turbines being modeled for conventional resources are reportedly capable of burning up to 50% hydrogen with minor modifications, meaning the current resource assumptions do not foreclose hydrogen blending as a future possibility.

- Stewart asked to confirm that the decisions being made for the 2026 IRP leave the door open for hydrogen to be incorporated in future cycles as the technology and supply infrastructure mature. Bob replied that the generic CT's that Santee Cooper has evaluated have been based on the GE H class technology, which reportedly can burn up to 50% hydrogen based on vendor and manufacturer information, and with minor changes, more so. It's not that hydrogen isn't an option for conversion or blending on the existing technologies that are being modeled for conventional resources. It's just that, given no clear plans for pipeline development, no clear plans for on-site production, it's a little hard to depend upon hydrogen as a dependable fuel source. Santee Cooper will accommodate it as soon as advancements are viable.
- Taylor asked whether Santee Cooper is considering modeling solar-plus-storage or solar-plus-onshore-wind as hybrid resource options in the IRP. Will explained that while hybrid configurations are used by neighboring utilities, Santee Cooper's preference is to continue modeling solar and battery storage as separate competing resources. This approach allows the model to evaluate the independent contribution of each technology and aligns with Santee Cooper's procurement process, which pursues solar through energy-only solicitations. Bob added that modeling a specifically designed hybrid installation is analytically challenging, as it requires fixing a particular solar-to-battery configuration and AC-DC ratio, making it difficult to evaluate the full range of possible combinations. He clarified that Santee Cooper does receive and evaluate hybrid facility offers through its procurement process, so the modeling preference does not reflect any bias against hybrid projects in practice.
- Taylor followed up by asking whether the model could still capture the ELCC synergies between solar and storage even without a hybrid resource option. Bob confirmed that the team intends to incorporate those synergies by applying conservative ELCC assumptions derived from the portfolio surfaces developed by PowerGEM, translating the combined reliability benefits into the modeling framework even though Encompass cannot dynamically simulate the full ELCC surface during optimization. He noted that the methodology is still in early testing and that specific details are not yet available.

Will and Bob described two planned methodology changes for the 2026 IRP. First, probable new large loads will be modeled using a separate high load factor load shape in Encompass, distinct from the underlying meteorological year load shape used for the existing customer base. This reflects the fundamentally different usage profile of data centers and similar industrial customers and is expected to improve modeling accuracy while also making it easier to evaluate load-related sensitivities. Second, the scope of DSM in the Santee Cooper IRP will be adjusted so that only Santee Cooper's own market potential study results are reflected in the low, medium, and high DSM scenarios. Central Electric's cooperative DSM programs, which are aggregated across more than 20 individual co-ops, will instead be embedded within Central's load forecast, aligning each entity's DSM planning with its own IRP process and better reflecting how those programs are developed and managed.

- Chelsea asked for clarification on the DSM scoping change, specifically whether Central's DSM assumptions would remain fixed across Santee Cooper's low, medium, and high scenarios while only Santee Cooper's own DSM varies. Will confirmed that is correct, noting that Central's load forecast will be provided net of their DSM assumptions as a single input. He acknowledged that how Central's DSM is treated within high and low load scenarios is still to be determined, and that the specifics will be discussed when the final load forecast is presented at the June meeting.

Will then used Chelsea's question as a transition to briefly recap the integration cost methodology change discussed earlier, confirming that the static \$/MWh integration cost adder will be replaced with dynamically modeled incremental operating reserves derived from the integration study results. Joel will present those results at the June meeting, at which point the team will walk through exactly how they will be applied in IRP modeling. Bob added that preliminary testing suggests this change will not materially alter portfolio optimization outcomes or resource selection, though it will affect how operating reserves are dispatched in production cost modeling.

For the 2026 IRP, Santee Cooper will add a reliability verification step to its planning process, running optimized portfolios back through the SERVIM probabilistic model to produce quantitative loss-of-load probability metrics. This responds to a request from the 2023 IRP process, where reliability assessment was qualitative rather than quantitative, and aligns with practices adopted by other utilities. Bob noted that any portfolio falling short of the reliability threshold will have peaking resources added until it meets the minimum requirement, which may result in most portfolios converging to similar reliability outcomes. The team acknowledged this is a new process that will require building supporting workflows, but expressed confidence it will be ready for the 2026 IRP filing.

- Chelsea asked whether peaking resources added to meet reliability thresholds would be applied uniformly across all portfolio types, or whether greenhouse gas and renewable-focused portfolios would instead use batteries or other storage resources to address reliability shortfalls. Bob acknowledged it as an important design question, noting that any added resource would need to be consistent with the characteristics of the portfolio in question and that a pure renewable or GHG-constrained portfolio would likely require a battery addition rather than a combustion turbine. He indicated the team is open to using battery additions as a neutral, portfolio-agnostic approach to reliability compliance, but noted the methodology is still being worked through. Chelsea offered to share her experience and provide written comments following the meeting.

Will went on to confirm that the 2026 IRP will run the same base portfolio types as the 2023 IRP (economically optimized, no-new-fossil, coal retirement, and net-zero portfolios) with possible minor name changes. He noted that the team is monitoring federal Greenhouse Gas (GHG) regulatory developments and will present final portfolio assumptions, including how GHG scenarios will be handled, at the June working group meeting. Bob then outlined plans for an Encompass model benchmarking exercise, requested by the Commission, which will follow the approach used by Dominion and Duke. The process involves running the existing

Encompass model against a recent historical year using actual load conditions, resource availability, outages, and fuel prices to evaluate how closely the model replicates real-world dispatch outcomes. Bob expressed confidence the exercise will not surface major issues, characterizing it primarily as a data management effort, with results targeted for presentation at the June meeting or Meeting 12 at the latest.

- Taylor Allred asked whether Santee Cooper has considered incorporating gas turbine supply chain delays into IRP modeling, noting that turbine lead times have been growing and could extend further by the time procurement begins following IRP completion and regulatory review. Will acknowledged the concern but explained that the IRP uses generic first-year-available assumptions developed with internal and external engineering input, representing a reasonable baseline development timeline across all resource types. He noted that capital cost sensitivities, such as the 50% thermal cost increase run in the 2023 IRP, partially address this risk, and that comparing base portfolios against the no-new-fossil case already provides some insight into what resource builds might look like if thermal resources faced delays.

Will expressed some reluctance to model resource-specific delay sensitivities in a generic screening tool, but acknowledged Taylor's point that a targeted first-year-available sensitivity could produce useful information distinct from simply comparing against the no-new-fossil portfolio, for example, showing whether a delayed thermal resource still produces a lower-cost outcome than a fully renewable build.

Will closed the IRP update section by inviting stakeholders to submit any additional methodology or assumption changes not covered in the presentation and acknowledged that several of the improvements being incorporated into the 2026 IRP originated from working group feedback over the years.

Meeting Closeout

– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart reviewed the action items captured during the session, with Taylor adding one additional item that was incorporated after a brief discussion. These are listed below in the section titled commitments and next steps. Stewart also reminded attendees that a meeting summary would be distributed for review and recapped the upcoming schedule. Members were encouraged to suggest topics or presenters for future meetings.

Will made a light-hearted request for leniency in the post-meeting survey, noting it was his first time presenting at a stakeholder meeting. Stewart closed with a note of appreciation for the working group's engagement, observing that the dialogue has evolved over the years into the kind of constructive, collaborative conversation the working group was designed to foster.

Commitments and Next Steps

ACTION ITEM – noted during the meeting discussion	By WHOM
1. Provide a follow-up on Cherokee and Rainey CC measures	Resource Planning
2. Share the results of the Integration Study when complete	Resource Planning
3. Consider 2X1 Natural Gas Combined Cycle as a sensitivity	Resource Planning
4. Ensure that Santee Cooper is not making decisions that preclude logical use of Hydrogen when it becomes a viable fuel source	Resource Planning
5. Attempt to share benchmarking results with the Working Group by June	Resource Planning

6. Consider the first year of available of resources and how these impact the IRP Resource Planning
7. Examine and consider accounting for the synergy between ELCC and Resource Planning
resources

Next Steps:

- The next Working Group meeting is scheduled for June 3, 2025
- The next general notice meeting is targeted for June 11, 2026
- Members wishing to present a topic at a future meeting may contact Ellie Gallagher or Will Brown

APPENDIX A

List of Stakeholder Working Group Members and Attendees

ORGANIZATION	MEMBER / ALTERNATE	April 9 th ATTENDEES
Office of Regulatory Staff	Findlay Salter Jeffery Gordon Julian McElhane Shane Hyatt	Julian McElhane
SC Dept of Consumer Affairs	Jake Edwards Roger Hall	Jake Edwards
SC Dept of Natural Resources	Elizabeth Miller Lorianne Rigg	Elizabeth Miller
SC Dept of Environmental Services	Marie Brown Rhonda Thompson	Marie Brown
Central	Caleb Bryant Leslie Maley	Heather Zrust
J. Pollock	Jeffery C. Pollock Jonathan Ly	Jonathan Ly
Century Aluminum	Michael Early 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	
Carolinas Clean Energy Business Association	Hamilton Davis John Burns	Hamilton Davis John Burns
Conservation Voters of South Carolina	Erin Siebert Jalen Brooks-Knepfle John Brooker	Jalen Brooks-Knepfle
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

Southern Environmental Law Center	Anna Sommer Chelsea Hotaling Kate Mixson Nina Peluso Thomas Gooding	Chelsea Hotaling Kate Mixson Thomas Gooding
Sierra Club	David Rogers Dori Jaffe Mikaela Curry Sari Amiel	
Vote Solar	Jake Duncan	Jake Duncan
Santee Cooper Resource Planning	Clay Settle Ellie Galagher Will Brown	Ellie Galagher Will Brown
nFront Consulting	Bob Davis Jonathan Nunes	Bob Davis
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

Southern Environmental Law Center	Shelley Robbins
Office of the Regulatory Staff	Braden Relyea
Central	Christopher Goering
SC Energy Office	Richelle Tolton
DNV Consulting	Daniel Pardo
PowerGEM	Joel Dison
Resource Innovations	Jim Herndon
Santee Cooper	Andrew Skinner Carl Ciullo Ricky Gaskins Steven Roys