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DISCUSSION DRAFT

Santee Cooper Rates Stakeholder Engagement

Technical Working Group Meeting #1 – Meeting Summary

Date: November 5, 2025

Time: 9:01 – 11:44 am

Location: Virtual Meeting via Zoom, Vanry Associates facilitating

Meeting: Santee Cooper Stakeholder Working Group Session #1

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

- Meeting Information & Materials
- Session Participation
- Topics, Presenters, and Discussion
- Action Items & Next Steps
- Appendix - List of Technical Working Group Members & November Meeting Attendees

Meeting Information & Materials

The Santee Cooper Rates team held its first Rates Technical Working Group meeting on November 5, 2025. The newly formed Technical Working Group is a core component of a more robust engagement process as part of Santee Cooper's commitment to solicit feedback in developing retail rates. The meeting formally launched the working group and provided a detailed review of retail rate cost allocation methodologies.

Session Participation

The Technical Working Group is intended to comprise a set membership of organizations representing diverse interests and perspectives, including government and non-governmental organizations, regulatory agencies, and customer groups. The Santee Cooper Resource Planning team invited a representative from a select group of organizations to join the working group and assign a primary member. A number of individual customers were also invited, to help ensure a wide perspective of views.

Appendix A includes an initial list of members invited to join the technical working group and those who attended the November 5th meeting.

Topics, Presenters, and Discussion

The meeting agenda, presentations, and draft charter were emailed to members on November 3, 2025.

Welcome and Agenda
– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart Ramsay of Vanry Associates opened this first Technical Working Group meeting for the Santee Cooper Rates Process, welcoming participants and outlining the session's objectives. He reviewed the agenda, which included an overview of the draft charter to guide the group's work, a presentation by NewGen Strategies on cost-of-service principles, and a discussion of Santee Cooper's current and historical cost-of-service practices led by Devin Ritter. Stewart encouraged questions and participation, as the meeting was designed as an open, conversational forum to build a shared understanding of key concepts, gather stakeholder perspectives, and confirm next steps and action items.

Introduction and Purpose
– Mike Smith, Director, Budget, Billing, & Pricing, Santee Cooper

Mike emphasized the Technical Working Group's importance to Santee Cooper and to Santee Cooper's overall rate development approach. Reflecting on lessons from the previous rate study, he noted that while many valuable comments were received, several arrived too late to influence rate adjustments. The working group, as part of a broader stakeholder engagement process, is intended to capture people's perspectives in these conversations earlier, allowing for a genuine exchange of ideas on key cost-of-service and rate-making concepts. Mike underscored that there are many valid approaches to rate design and encouraged people to engage openly in dialogue about alternatives and improvements.

Turning to the draft charter distributed in advance, Mike described it as a starting point for defining how the group will work together. He invited people to review the document, offer feedback within a week, and help shape a shared understanding of expectations and process. A revised version incorporating comments will be circulated to the group.

Mike concluded by introducing Scott Burnham, Partner at NewGen Strategies and Solutions, highlighting his long-standing role in Santee Cooper rate studies and his expertise in cost-of-service methodology.

Cost of Service Overview
– Scott Burnham, Executive Consultant, NewGen Strategies and Solutions)

Scott opened his presentation by outlining the session's purpose: to review foundational cost-of-service concepts and explain how they inform Santee Cooper's ratemaking process. He expressed appreciation for Santee Cooper's openness and collaboration over many years. He explained that his remarks would focus on cost-of-service theory, with Devin Ritter to follow with Santee Cooper–specific details.

Scott outlined that rate design generally follows five steps: first, determining the revenue requirement, which is the total amount the utility needs to operate for a given period. Next, costs are allocated by unbundling them into utility functions like production, transmission, and distribution; classifying them as fixed or variable, or as demand-, energy-, or customer-related; and then assigning them to customer classes, such as residential, commercial, and industrial, based on how those customers use the system. After cost allocation, rate design begins, and this stage always involves policy considerations that influence final rate structures. Although utilities can be investor-owned, cooperatives, or public entities like Santee Cooper, and each has its own accounting practices, structures, and objectives, the overall five-step rate-making framework remains consistent, with only subtle differences across utility types.

- Eddy Moore (Southern Alliance for Clean Energy) asked how the size category of a utility, small, medium, or large, affects ratemaking, noting that Santee Cooper is unique because most of its load is wholesale despite having retail customers. Scott substantively explained that size can influence cost structures: smaller utilities often cannot afford their own generation and therefore operate differently from larger utilities, and larger systems can spread fixed overhead costs (such as labor, management, legal, and HR) across more customers, creating economies of scale. Smaller utilities, with fewer customers to absorb these fixed costs, may end up with higher per-customer charges. He agreed that Santee Cooper's structure is unique but emphasized that these size-related cost dynamics can lead to subtle differences in ratemaking.

Scott went on to explain that a cost-of-service study begins long before rates are set, supported by ongoing financial forecasting, load research, AMI data analysis, and system-loss evaluation. Utilities must assess when rates need to change, how long new rates should remain in place, and how future load—such as rapidly growing data center demand—may affect costs. For Santee Cooper, a unique step involves its annual cost-of-service process for Central Electric Power Cooperative (Central) under their coordination agreement, which determines a revenue credit that is deducted from the total revenue requirement before retail rates are calculated.

- Eddy noted that because most costs and revenues relate to Central, retail customers have a strong interest in transparency around that process, since even small changes in how Central's costs are treated can significantly affect retail rates. Scott noted this as a good comment.

Scott continued that while Santee Cooper's retail rate study looks at the utility as a whole, the Central wholesale process is a separate, annually conducted cost-of-service exercise with its own schedule, though many of the underlying analyses, such as financial forecasting, load forecasting, and long-term planning, apply to both. He emphasized that Santee Cooper's financial forecast is a cornerstone tool, projecting 30 to 50 years into the future to determine when retail rates may need to change, what investments are coming, and how revenues must adjust to support those costs.

- Eddy asked whether the forecast also identifies strategies to lower rates. Scott confirmed that it does, noting that Santee Cooper continually evaluates long-term options to pursue required investments at the lowest possible cost, consistent with a least-cost planning approach.

Scott next discussed that advanced metering infrastructure (AMI) provides real-time, highly accurate usage data, replacing the delays and inaccuracies of old analog meters. AMI enables utilities like Santee Cooper to validate customer data, track hourly and sub-hourly usage, and better understand system peaks, customer-class peaks, and individual maximum demands, all key inputs for cost allocation and rate design. This granular data also allows utilities to predict and measure customer responses to rate structures, such as new demand-related or time-of-use rates intended to shift consumption away from costly peak hours. AMI supports behavioral incentives by signaling when electricity is more expensive to produce, helping customers and the utility save money. He also noted that load forecasting incorporates historical customer behavior and class-level trends into financial and resource planning, and that current growth pressures—particularly from data centers—are significantly reshaping utilities' long-term load expectations.

- Eddy asked how far into the future projected load growth can affect current rates, noting that in investor-owned utilities, rates are usually tied to a "test year" based on actual, verifiable costs. He cautioned that forecasts extending too far ahead can introduce uncertainty or "phantom" costs and observed that, traditionally, a higher load forecast tends to lower rates and vice versa. Scott agreed that this is an important issue and explained that it depends on the relationship between a utility's embedded and marginal costs. If a system has excess capacity, additional load can reduce costs per unit because fixed costs are spread across more sales. However, when marginal costs exceed embedded costs, additional load can increase expenses. For Santee Cooper, he said, rate studies typically use a one- to three-year outlook, depending on the degree of certainty about future costs and investments. The most recent study, for example, relied on a one-year period due to higher uncertainty at that time.

- Eddy noted that only the past 12 months of sales would qualify as “known and measurable,” with any future assumptions treated as adjustments. Scott agreed, emphasizing that while historic data form the foundation, some forward-looking judgment is necessary to produce useful results. He described how analysts integrate behavioral and policy factors, such as electric-vehicle adoption, changes in national tax incentives, and shifting customer patterns, into the forecast to make it as realistic as possible. These assumptions, he said, are grounded in observed trends but must account for evolving conditions that influence both system demand and future rate requirements.

Moving on to load forecasting, Scott explained they incorporate weather normalization to avoid basing rates on atypical conditions, along with econometric analysis that considers factors like state and national policies, local job growth, and customer responsiveness to price signals (elasticity of demand). System losses are also accounted for, as electricity dissipates during transmission and distribution. AMI, fully deployed at Santee Cooper in 2021, provides highly accurate, real-time usage data, improving load forecasting, cost allocation, class determination, and bill impact analysis. AMI data reveals the diversity of customer usage, highlighting that utilities must invest to meet peak demand for high-use customers while also serving low-use customers, which drives costs. Finally, the revenue requirement step allocates total utility costs, including fuel, operations, debt service, capital improvement funds, and other obligations, across customer classes to determine the net retail revenue requirement, forming the foundation of the cost-of-service and rate design process.

- Eddy asked how observers can link Santee Cooper’s projected revenue requirements to actual expenditures, noting that in investor-owned utility rate cases, prudence reviews are based on verified costs from a past test year. Scott explained that Santee Cooper’s cost-of-service analysis draws on its financial forecast, which incorporates known obligations such as fuel, purchased power, debt service, and lease payments, along with reasonable projections for future investments. He noted that some cost components, such as fuel and purchased power, include separate cost-recovery mechanisms to address uncertainty. Mike added that Santee Cooper’s budgeting process is reviewed and approved annually by its Board of Directors and updated quarterly, with results and forecasts presented publicly. He emphasized that as a cost-based, non-profit utility, Santee Cooper must recover actual costs as they occur and has no shareholders or external funding sources to absorb overruns.
- Eddy observed that this approach differs from the retrospective model used in traditional rate cases, where utilities justify rates based on actual spending. He suggested that projecting costs forward could reduce the need for external review of rate decisions. Stewart responded that forward-looking test years are increasingly common across the industry, particularly in jurisdictions experiencing growth, because historical test years can lag behind evolving costs and fail to support necessary investments. Eddy acknowledged the trend but noted that consumer advocates often raise concerns about reduced oversight when forecasts replace historical data.
- Jeffry (Jeff) Pollock (Pollock Inc.) added that in prior studies, the Board effectively set the revenue requirement before the cost-of-service analysis began, and he sought confirmation that this would remain the case. Mike confirmed there were no planned changes. Jeff then raised a concern about transparency, noting that while Central’s cost-of-service process offsets part of the overall revenue requirement, it is not visible to retail customers. He suggested that this limits stakeholders’ ability to review cost allocations fully. Mike replied that a bilateral contract governs the Central process and will remain separate from the retail rate-setting process.

Scott concluded his presentation focusing on Santee Cooper’s cost allocation process, where total costs are unbundled, classified, and assigned to different customer classes. He explained that generation, transmission, distribution, and customer-related functions each have distinct costs. Generation costs include fixed costs for capacity and demand, plus variable energy costs. Transmission costs are largely fixed in the Southeast, while distribution costs are allocated based on the peak demand of each customer class, reflecting diversity in usage. Customer-related costs cover billing, service, and program administration, sometimes using weighted measures for industrial customers. The methodology relies on cost causation principles: demand-related costs use coincident peak (CP) methods, energy-related costs use kilowatt-hour sales, and customer-related costs are assigned by customer counts or weighted factors. Santee Cooper applies variations like multiple CP or non-coincident peak (NCP) hours to accurately allocate costs, capturing seasonal and class-specific demand patterns. The approach ensures that each class bears costs proportional to its contribution to system demand, energy usage, and customer service needs.

Santee Cooper Cost of Service Practices
– Devin Ritter, Manager, Pricing, Santee Cooper

Devin Ritter provided an in-depth explanation of the utility's cost-of-service and rate-setting process, detailing how the utility develops revenue requirements, allocates costs, and sets rates for different customer classes. He emphasized that Santee Cooper's pricing team handles cost-of-service studies, rate design, competitive analyses, and revenue requirement development, using a methodology grounded in equity, transparency, and defensible allocation. The rate development process is lengthy, typically taking at least 18 months and involving extensive stakeholder engagement and public comment periods; the fastest legally compliant timeline is about 10–12 months. Ritter stressed that rates are only adjusted when a revenue-to-cost deficit occurs, and even then, other financial levers—such as O&M budget adjustments or debt restructuring—are considered before proposing a rate increase.

Santee Cooper's revenue requirements differ from investor-owned utilities in that they do not include depreciation, return on equity, or income taxes. Instead, the key components include projected fuel and purchased power costs based on load forecasts and production cost modeling; non-fuel O&M expenses from the board-approved corporate budget; debt service on long-term and short-term borrowings; payments to the state (1% of projected revenues); working capital to cover timing differences between expenditures and revenue collection; and payments in-lieu of taxes to municipalities. A 9% Capital Improvement Fund (CIF) margin is applied to ensure sufficient funds for capital projects while maintaining strong credit ratings and minimizing the need for borrowing.

For the 2025 test year, Santee Cooper's total revenue requirement was just over $2.2 billion, with the largest portion coming from fuel and purchased power ($927 million combined), followed by debt service (~$500 million) and the CIF (~$200 million). After subtracting off-system revenues, wholesale sales, and miscellaneous income, the resulting cost of service allocated to retail customers was $843 million. Ritter highlighted that this cost-of-service study directly informs rates for residential, commercial, industrial, and lighting customers, with the process designed to ensure fairness, transparency, and alignment with Santee Cooper's board-approved pricing principles. He also noted the availability of annual pricing reports, which provide analyses of rate compliance, historical returns, and comparisons with other utilities, offering stakeholders a transparent view of the utility's rate-setting outcomes.

- Eddy asked whether the investment income shown on the prior slide was captured within the "interest and miscellaneous income" category or represented a separate item. Devin confirmed that the four million dollars shown as interest and miscellaneous income includes all investment earnings, which remain a relatively minor component of total revenues.
- Eddy then asked whether the CIF is applied equally to all customer classes. Devin explained that while the CIF is calculated in the same manner within the overall revenue requirement, the share each class pays varies based on the allocation methodology.

- Eddy followed by asking how the CIF is affected if Central chooses not to participate in a resource. Devin clarified that in such cases, Santee Cooper would assign CIF costs related to that non-shared resource solely to retail and industrial customers, with Central not contributing to those specific obligations.

Devin detailed Santee Cooper's process for transforming the total or net cost of service into customer rates through functionalization, classification, and allocation. Functionalization begins by assigning costs to production, transmission, distribution, or customer functions. Most O&M expenses are directly functionalized using the FERC Uniform System of Accounts, while items like debt service, CIF, working capital, and payments to the state are functionalized using methodologies such as net plant ratios or O&M ratios. For example, debt service and CIF are allocated based on the ratio of depreciated assets in each function, ensuring the funding source does not affect customer rates. Administrative and general costs, approximately $130M, are allocated to functions based on payroll ratios, while non-retail revenues, like wholesale or off-system sales, are credited to the function that generated the revenue.

Once functionalized, costs are classified as demand-related, energy-related, or customer-related. Production costs are divided between energy (e.g., most fuel and purchased power) and demand (e.g., capacity, spinning reserves, or fixed generation costs), transmission and distribution costs are classified entirely as demand, and customer costs are classified to the customer function but tracked in detail for allocation. Allocation to customer classes uses factors that reflect actual cost drivers: production demand is allocated using four coincident peaks (two winter, two summer months), transmission via 12 monthly coincident peaks (12CP), and distribution via 12 monthly non-coincident peaks (12NCP), while energy costs are allocated based on forecasted kilowatt-hour usage adjusted for losses. Industrial customers do not use the distribution system, so they are excluded from distribution allocations.

Devin highlighted that integrating AMI data has improved the accuracy of load and peak estimates. Previous methodologies relied on small meter surveys, which could misrepresent class peaks. AMI data allows more granular, near-real-time visibility, showing, for example, that residential peaks were higher than previously estimated. This improved precision in functionalization, classification, and allocation enables Santee Cooper to assign costs more equitably across customer classes, refine rate design, and develop more accurate revenue forecasts that align with actual customer usage and system behavior.

- Eddy noted that while a small share of fuel costs is allocated to demand to account for spinning reserves, the inverse principle could also apply to fixed production costs. Some generating units, such as peakers in Hilton Head or Myrtle Beach, may operate infrequently and primarily serve capacity. In contrast, baseload units, such as the nuclear plant, run almost continuously and therefore serve both capacity and energy functions. He observed that the South Carolina Department of Consumer Affairs (SCDCA) had raised this issue in the last rate case, suggesting that generation assets should be partly allocated to energy based on their actual performance. Devin agreed this was a valid point and confirmed that Santee Cooper had analyzed the implications of that argument in subsequent slides that showed how alternative allocation approaches could affect class-level revenue requirements.

Devin emphasized that allocation choices significantly affect class-level revenue requirements because customer classes have very different usage patterns. Industrial customers, with high load factors above 90%, consume energy almost continuously, representing a smaller share of peak demand at 25% of the 4CP allocator, but a larger share of energy usage, nearly 40%. In contrast, residential customers have lower load factors, with usage highly seasonal and peaking during winter and summer. Using the cost-of-service model, functionalized and classified costs are allocated to residential, commercial, lighting, and industrial firm classes using appropriate allocators (4CP for production demand, net energy for load for energy costs, and 12CP for transmission demand). Industrial non-firm customers are excluded from allocations because the system is not built to serve their firm load, and their costs are treated separately. This allocation methodology ensures costs are distributed equitably based on how each class uses the system, directly affecting revenue requirements by class.

- Steve Thomas (Century Aluminum) asked whether Santee Cooper's use of the 12CP allocator for transmission costs was a FERC requirement or an internal decision. Devin explained that it is a Santee Cooper decision rather than a FERC mandate.
- Steve asked how long that method had been in place. Devin said it was used in the previous rate study and likely for quite some time, though he would confirm the exact duration. Scott added that 12CP has been used since he began working with Santee Cooper and that it aligns with FERC-approved practices, which is part of the reason the utility continues to apply it. Devin then noted that the 4CP allocator is used for production demand expenses, which total about $279 million.

Devin's next points (referencing slide 20) responded to contradictory stakeholder feedback from the last rate study by showing how different production demand allocators would impact class-level revenue requirements. The current approach uses four CP (coincident peaks), considered appropriate because it aligns demand-related costs with the correct functional classification. If switched to 1CP, residential costs would rise about 7% and industrial costs would fall slightly; 12CP has the opposite effect. Net energy for load is included illustratively to show the extreme impact of energy-based allocation. A hybrid allocator (average plus excess demand) would reduce residential and commercial costs while increasing industrial costs by over 10%. This analysis was intended to clarify the potential effects of alternate allocators in response to stakeholder questions.

- Jake Edwards (SCDCA) confirmed that they typically recommend average and peak 12CP. Devin agreed.
- Jeff shared skepticism about the AED calculations and asked whether they could be shared. Devin agreed to get back to them with the math.
- Eddie commented that the only allocator that truly incorporates energy is net energy for load (NFL). While average and excess demand might seem energy-related, they are not, and the recommendation was not to allocate all production costs based solely on energy. He emphasized that the NFL column illustrates an extreme case, which no one requested, but it can be reasonable to allocate some fixed production costs to reflect the energy function in a defensible way. Devin added that the purpose of showing NFL is purely illustrative, as a "bookend" to demonstrate the potential impacts on class-level revenue requirements, not as a proposal for actual implementation.
- Jeff asked Eddy to clarify what he meant by a "production plant that serves an energy function." Eddy explained that a nuclear plant, which runs continuously, provides both steady capacity and significant energy, whereas peaker plants may run very little and primarily serve a capacity function. He argued that allocating costs identically across these functionally different plants is counterintuitive. Jeff noted that all generators provide both capacity and energy, with differences mainly in economics and dispatchability, rather than absolute capability. Eddy added that some experts in other jurisdictions have argued it is reasonable to allocate some fixed production costs based on the energy function, even if the plant's primary role is capacity. The discussion highlighted the functional differences between generation types and the rationale for selectively reflecting energy in cost allocation.

The discussion moved on to the methodology for allocating distribution and customer costs across different classes. Most distribution costs are allocated using a 12CP allocator, while some use a net plant-level allocator to separate metering costs, avoiding unfair allocation to unmetered classes like lighting. Customer expenses are allocated using a mix of methods, including the number of customers, weighted customer counts for complex industrial accounts, and direct assignment for program-specific costs such as DSM or lighting. Industrial non-firm customers are treated separately, with their projected revenues functionalized and allocated back to other classes, resulting in a zero net effect overall. Additionally, a policy adjustment was applied to mitigate large increases for residential customers due to updated AMI data, ensuring gradual rate changes, avoiding rate decreases for any class, and maintaining a more balanced approach after nine years without a base rate increase.

- Eddy asked whether the reduction in the residential demand charge from the initially proposed $10 per kilowatt to $8 was part of the broader policy adjustment or a separate change. Devin clarified that it was a separate, revenue-neutral modification: Santee Cooper lowered the demand charge while slightly increasing the energy rate, keeping the residential class contribution at $266 million.
- Eddy noted concerns that this adjustment might signal a phased increase toward higher demand charges in the future. Devin explained that it did not alter total residential revenue but represented a gradual move toward aligning charges with cost causation. The shift kept some production demand costs in the energy charge, narrowing the spread of rate impacts across households. He added that the new demand rate may prompt behavioral changes that reduce residential peak demand, potentially lowering future costs. Mike reinforced that the primary intent was to minimize extremes within the residential class by reducing the number of customers facing unusually large increases or decreases.
- Eddy asked for data on how many customers fall into the top tiers of rate changes. Acknowledging Eddy's question, Mike confirmed they do not have an answer yet. He confirmed Santee Cooper would continue to gather data through the winter, analyze a full year of data and report those findings to the Board in March.
- Steve offered an anecdote, noting that his 88-year-old mother in Moncks Corner keeps Santee Cooper's peak hours posted on her refrigerator to guide when she can run appliances, evidence, he said, that the new rate design is influencing customer behavior as intended. Devin appreciated the comment.

Closing off his presentation, Devin summarized the adjusted cost-of-service results and their impact by customer class. He explained that the most recent rate study resulted in an overall average increase of 4.9 percent after policy adjustments. Residential customers saw a net $21 million increase, tempered by a $13 million downward adjustment to avoid an abrupt jump that would have been closer to 12 or 13 percent without the policy offset. Commercial customers received a $7.6 million upward adjustment to prevent a rate decrease, keeping their increase near the overall average. Industrial customers experienced the smallest rate change since they contribute less to peak demand costs. However, they remain most sensitive to fuel cost fluctuations, which are passed through separately rather than managed through the rate study process.

Meeting Closeout

– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart and Mike expressed their appreciation to the team and the presenters. Stewart confirmed that the summary would be available by November 21, asking participants to review it and provide comments within a week of receipt so that a final version could be completed promptly.

Mike also reminded the group that a draft Technical Working Group charter had been circulated and invited members to return any comments or suggested edits within the same one-week period. Stewart added that the charter was meant to be a working draft, open to input rather than finalized.

Stewart invited participants to share feedback on the meeting's structure and value. Several attendees expressed appreciation for the discussion and the level of engagement. Stewart emphasized that the goal of these sessions is open dialogue between Santee Cooper and stakeholders, and that adjustments to format or content would be welcomed.

The next Technical Working Group meeting was tentatively scheduled for January 20, with details and materials to be confirmed closer to the date. Stewart closed by thanking everyone for their participation and thoughtful contributions, noting that this level of engagement was exactly what Santee Cooper hopes to foster through the ongoing stakeholder process.

Commitments and Next Steps

ACTION ITEM – noted during the meeting discussion

1. Santee Cooper Rates to send Draft Charter to members for comments
2. Santee Cooper Rates to provide more information to members about the 12CP Transmission cost allocation history
3. Santee Cooper Rates to provide additional information to members on the math behind the AED allocation calculations

Next Steps:

- The next Technical Working Group meeting is tentatively scheduled for January 20, 2026
- Members are encouraged to suggest future topics. Any member interested in presenting at a future meeting may contact Jack Grooms

APPENDIX A

List of Technical Working Group Members and Meeting Attendees

ORGANIZATION	MEMBER	Nov. 5th ATTENDEES
A.O. Smith	Gilbert Chavez	
Aalberts	James Sturgeon	James Sturgeon
AirGas	Eric Steicher	
Albany International	Marcus Moody	
Amrize (Formerly Holcim	Brandon Van Damme Chris Dueweke	
AVX	Ryan Parry	
Canfor (Formerly New South)	Charles Smith	
Central	Cole Price	
Century Aluminum	Stephen Thomas	Stephen Thomas
Charleston Air Force Base	Ben Adams	
DC Blox	Todd Nafziger	
Giant Cement	Scarth MacDonnell	
Grand Strand Water & Sewer Authority	Dick Sanders	
Heidelberg Materials (formerly SEFA)	Stephen Zasmimovich	Stephen Zasmimovich
Ineos	Brian Bach	Brian Bach
Interfor	Brett Mayeaux	
International Paper	Nate Hewes	
JW Aluminum	Ronke Akano	
Lanxess Corporation	John Dougherty	
Linde (Praxair)	Jennifer Hunsperger	
Matheson	Audie Bremer	Audie Bremer
Messer	Michael Peters	
Metglas Inc.	Jerry Smith	
Nucor	Bradley Powell Mike Lavanga	Mike Lavanga
Office of Regulatory Staff	Shane Hyatt	
Pollock, Inc.	Jeff Pollock	Jeff Pollock Jonathan Ly
Pret Group (Wellman)	Charles (Chuck) Grier	
Residential Customer	Dennis Wodja Samantha Kumaran	
Resonac Graphite	David Whichard	
USA Wool	Scott Goodman	
Small Business Chamber of Commerce	Frank Knapp	

SC Department of Consumer Affairs (SCDCA)	Roger Hall	
Southern Alliance for Clean Energy (SACE)	Eddy Moore	Eddy Moore

Also in Attendance

1-972-837-5426		TBC
Central		Heather Zrust
SC Department of Consumer Affairs (SCDCA)		Jake Edwards

**Members listed in alpha order by organization*

Santee Cooper Rates	Mike Smith Devin Ritter Jack Grooms Kristin Bennett	Mike Smith Devin Ritter Jack Groups Kirstin Bennet John Calhoun Zachary Smith Elijan Lowe
NewGen Strategies & Solutions	Scott Burnham Meghan Helper	Scott Burnham Meghan Helper
Vanry Associates	Stewart Ramsay Peter Claghorn Yvette Smith	Stewart Ramsay Peter Claghorn Yvette Smith