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Santee Cooper Rates Stakeholder Engagement

Technical Working Group Meeting #2 – Meeting Summary

Date: January 20, 2026

Time: 9:01 – 11:23 am

Location: Virtual Meeting via Zoom, Vanry Associates facilitating

Meeting: Santee Cooper Stakeholder Working Group Session #2

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 second Rates Technical Working Group meeting on January 20, 2026. The organization is committed to strengthening its engagement with customers and stakeholders in developing retail rates through a more consistent, structured process. In this, it has formed a technical working group to serve as a focused forum for reviewing rate concepts and providing meaningful feedback. More information and meeting materials can be found on the Rate Stakeholder Meetings webpage.

Session Participation

The Technical Working Group comprises a set of organizations representing diverse interests and perspectives, including government and non-governmental organizations, regulatory agencies, and customer groups. Several industrial and commercial customers were also in attendance, invited to ensure a wide range of views.

Appendix A includes the list of working group members and others who attended the January 20th meeting.

Topics, Presenters, and Discussion

The meeting agenda was emailed to members on January 19, 2026.

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

Stewart Ramsay opened the meeting by outlining the agenda and session flow: beginning with a review of the working group agenda and charter, followed by introductions, a presentation on the background and assumptions underlying the current rate design, and a detailed discussion of Santee Cooper's rate design with particular focus on industrial rates. He encouraged participants to ask questions throughout and noted that additional time was reserved for broader discussion at the end. Stewart then reviewed the working group charter, noting that it was developed from initial stakeholder input, posted publicly for comment, advanced without revision due to the absence of feedback, and intended to guide open dialogue on Santee Cooper's retail rates and ratemaking process while enabling the technical working group to contribute diverse perspectives and expertise.

Introduction
– Greg McCormack, Senior Director, Financial Planning, Santee Cooper

Greg McCormack introduced himself in the context of recent organizational changes within Santee Cooper, noting shifts in leadership responsibilities related to rates and financial forecasting, with rate-related functions now reporting to him. He provided a brief background on his tenure at Santee Cooper, including prior work in the rates group and more recent involvement in financial forecasting and IRP-related activities.

Greg emphasized Santee Cooper's role as a public power utility, explaining how the absence of a profit motive shapes its approach to rates, cost recovery, and customer engagement, and underscoring the importance of fair cost recovery and stakeholder input. He closed by signaling an intent to increase transparency and communication around the rate process, thanked participants for their engagement, and invited questions.

Rate Design Overview
– Scott Burnham, Executive Consultant, NewGen Strategies and Solutions

Scott Burnham outlined foundational concepts in electric rate design, framing rates as price signals for utility products and services, and emphasized that while utilities share common functions, differences in cost structures, assets, markets, and objectives drive unique rate outcomes. He reviewed the relationship between cost of service and ratemaking, describing how revenue requirements are developed, functionalized, classified, and allocated to customer classes based on cost-causation principles, and noted that while cost of service provides a technical foundation, final rates often diverge due to policy considerations. Rates were described as instruments for both recovering costs and influencing customer behavior in alignment with utility objectives.

He summarized widely cited rate design principles associated with James Bonbright, including practicality, clarity of interpretation, revenue adequacy, stability for both utilities and customers, fairness and equity across customer classes, avoidance of undue discrimination, and economic efficiency, measured by load factor. He noted that low rates are not, in themselves, a core principle, given the ongoing investment required to maintain and modernize utility systems and emphasized the importance of aligning rates with long-term infrastructure needs, asset replacement, and system efficiency.

The discussion then turned to external and internal factors shaping modern rate design, including inflation, volatility in fuel and power costs, supply availability, environmental and regulatory policies, power market structures, capital investment requirements, and emerging load growth patterns, particularly from large customers such as data centers. Additional considerations included conservation objectives, new technologies such as AMI, EVs, and distributed generation, and the growing complexity introduced by customer-facing technologies and policy-driven programs. He noted that rate design involves balancing competing objectives, including revenue adequacy, affordability, simplicity, equity, policy mandates, and competitiveness, with rate structures reflecting necessary compromises among these factors.

- Jeffry Pollock (Pollock Inc.) asked whether the use of rates for social engineering is more appropriately the responsibility of legislators or other public governing bodies, rather than utilities acting in a business capacity. He further questioned how effective electricity rates can be as a tool for addressing broader social or affordability objectives, given that electricity is only one of many costs households face and that there are practical limits to what rate design alone can achieve. Scott responded that social engineering embedded in rates is fundamentally an expression of public policy, not an independent utility initiative. He noted that in the public power context, utilities often act on behalf of municipal or local governments elected to set policy direction. When policies are established at the state level, they apply uniformly across utilities, including both public power and IOUs, helping maintain consistency.
- Stewart added that examples of social engineering typically follow explicit policy decisions made by governing bodies, with the utility's role being to determine how those policies are implemented through rates. Scott agreed, emphasizing that the central issue is the level at which public policy is determined, while the utility's function is to operationalize that policy within the ratemaking process.

Scott continued by contrasting embedded- and marginal-cost approaches, noting that most U.S. utilities still set rates based on embedded costs tied to historical investments, whereas marginal-cost applications are increasingly used for large new loads, particularly data centers, to limit cost exposure for existing customers. Traditional rate design was described as a three-part structure consisting of customer, energy, and demand charges, with customer charges recovering fixed customer-related and distribution costs, energy charges recovering variable costs such as fuel and variable O&M (Operations and Maintenance), and demand charges recovering fixed production, transmission, and capacity-related costs. The distinction between short-term fixed costs and long-term variability was emphasized, along with the expanding use of demand charges for residential customers to improve equity and cost alignment.

Special rate provisions were described as tools for managing risk and supporting cost recovery, including minimum bills, demand ratchets, budget billing, and energy cost adjustments. Minimum bills and ratchets were characterized as mechanisms to ensure recovery of infrastructure investments despite customer usage volatility, while energy cost adjustments were described as balancing mechanisms to manage commodity price volatility and support rate and revenue stability. Net metering was discussed as a policy-driven construct that offsets retail consumption with self-generation, raising fixed cost recovery issues as volumetric sales decline, with utilities employing various approaches such as alternative settlement periods, avoided cost valuation, net billing, buy all sell all structures, and fixed charges to address these impacts, depending on penetration levels and jurisdictional policy.

Industrial and non-firm rates were described as serving customers with high energy and demand usage and greater price sensitivity, often supported by three-part rates, time-of-use elements, and, in some cases, real-time or market-based pricing. While industrial loads are often characterized by high load factors, emerging evidence suggests variability among large customers such as data centers, potentially warranting differentiated rate classes. Non-firm or interruptible rates were described as trading reliability for lower prices, with customers accepting curtailment risk in exchange for pricing tied to avoided cost, marginal cost, or market signals, and requiring clear contractual terms that offer benefits such as lower customer costs and improved system asset utilization.

- Mike Lavanga (Stone Mattheis Xenopoulos & Brew (SMBX) on behalf of Nucor) asked whether data centers are participating in non-firm rates, noting their typically high load factors and questioning whether curtailable data center customers are emerging, potentially supported by backup generation.

Scott responded that he has not seen much interest in traditional non-firm rates so far, as many data center developers are prioritizing securing interconnection positions and capacity claims over negotiating arrangements involving self-generation, load sharing, or standby agreements.

- Stewart added that in other due diligence engagements, he has seen variations in non-firm arrangements, particularly in MISO, where some large data centers with backup generation agree to disconnect from the grid during defined emergencies, such as a Level 3 event. He explained that this structure reduces the need for the utility or the market to build additional generation solely to cover rare emergency conditions and represents non-firm service tied to grid criticality rather than continuous interruptibility. He also noted legislative movement in Texas pushing in a similar direction. Scott further emphasized that data center load is not monolithic, with meaningful differences between AI-focused facilities that require firm power and other applications, such as compute-intensive or quantum workloads, that can tolerate curtailment on short notice. He noted that these differences raise questions about whether all data centers belong in the same rate class and observed that some developers are increasingly willing to accept non-firm or conditional service as a faster path to interconnection rather than waiting several years for a new generation to be built.

Scott continued that non-firm service requires customers to have flexible load and the operational ability to curtail, and that such programs can exist in both systems with surplus capacity and those without. He described non-firm offerings as two-way arrangements that can benefit both utilities and customers. He then outlined emerging rate trends, including stronger pricing signals through time-of-use energy and demand rates, peak window demand charges, and increasingly granular on-peak, off-peak, and super-peak structures designed to better reflect cost drivers and influence load behavior.

Scott emphasized a broad industry shift toward greater fixed-cost recovery, citing higher fixed charges, higher or more complex demand charges, facilities or grid access charges layered onto traditional three-part rates, and minimum bills. These mechanisms were described as tools to recover infrastructure costs while still preserving some marginal price signals. He noted that large loads, such as data centers and crypto mining, have distinct characteristics: crypto loads are generally more interruptible, data centers typically require higher reliability, and manufacturing loads pose forecasting challenges due to uncertain production volumes.

Finally, Scott concluded by speaking to the scale and complexity of serving large and hyperscale loads, particularly for data centers exceeding 100 MW. He highlighted policy and design considerations, including growth paying for growth, the availability of excess capacity, transmission and interconnection requirements, responsibility for infrastructure costs, power supply procurement strategies, and extended construction timelines. He noted that data center loads are not inflexible and often ramp over time, even when systems must be built to accommodate full stated capacity upfront, creating ongoing cost-recovery and rate-design challenges that remain unresolved across many jurisdictions.

Santee Cooper Rate Design

– Devin Ritter, Manager, Pricing, Santee Cooper

Devin Ritter provided a detailed walk-through of Santee Cooper's rate design, explicitly linking the rate concepts Scott had previously discussed to their implementation, supported by results from the most recent rate study. He outlined the presentation scope, covering residential, small commercial, and industrial rates, including firm and non-firm offerings, demand sales adjustments, and the pricing rationale for each. He also closed outstanding questions from the prior technical meeting, clarified the long-standing use of 12 CP for transmission allocation, and corrected an industrial production demand allocation error, noting that the revised result aligned with expectations for a hybrid allocator between CP and energy.

Devin described the stakeholder process as an informal yet deliberate mechanism for gathering feedback outside formal rate-study periods, complementing the limited statutory comment window during official proceedings. He framed Santee Cooper's pricing principles as aligned with the Bonbright principles reviewed earlier, emphasizing efficiency through price signals, adequacy to ensure full cost recovery, and transparency in rate development. He reviewed the allocated revenue targets by customer class from the 2024 rate study, noting that the industrial total included both firm and non-firm service and required further disaggregation.

Focusing on residential rate design, Devin explained how functionalized revenue requirements were translated into rate components, including customer, energy, and demand charges, and how an explicit adjustment was made to reduce residential cost responsibility to avoid rate shock. He detailed the evolution from an initially proposed $10 per kilowatt (kW) demand charge to the adopted $8 per kW charge, shifting some cost recovery back into volumetric energy rates while preserving peak price signals. He noted the advanced metering infrastructure (AMI) role in enabling both rate design and billing, observed early evidence of peak-load reduction during summer peak windows, and explained the rationale for incremental customer charges for solar distributed generation (DG) customers to prevent cost shifts and ensure recovery of fixed transmission and distribution costs.

- Stewart shared a list of topics Jeffry posted to the Zoom chat: L-25 time of use periods, event triggers for additional on-peak hours and off-peak demand hours, transparency in estimating secondary and economy power pricing, FAC (fuel adjustment clause) recovery of third-party and imputed demand charges and gas transportation costs, and rate 25-LL availability provisions. Jeffry added that these issues had not received much attention during the rate study and that the working group was an opportunity to re-engage with them. Devin agreed and said he would address the interruptible and L-25 topics as the discussion naturally moved to them.

Devin summarized the small commercial GA-25, explaining that Santee Cooper initially allocated nearly all fixed costs to a non-coincident demand charge to align with larger commercial design and customer familiarity, resulting in a high demand charge and a small time-of-use energy differential. After receiving feedback on uneven impacts across load factors, Santee Cooper shifted distribution and transmission costs from demand to volumetric energy, reducing the demand charge's intensity and making the change less disruptive. He noted commercial peak shifting has been weaker than residential due to the small price differential.

Devin next addressed the industrial L-25, clarifying that firm industrial revenue requirements are much smaller than the combined industrial total because non-firm sales are a larger share. He described L-25 as largely cost-based, with transmission and production demand in the demand charge, production energy in the energy charge, and a customer charge, and noted the major change from L-17 was adding winter on-peak energy periods, which reduced the on-peak rate by spreading on-peak pricing across summer and winter months. Devin also outlined that L-25 includes both on-peak and off-peak energy periods, plus separate on-peak demand hours that determine billed demand, with an option for contracted off-peak demand at a discounted rate to encourage off-peak usage.

- Jeffry reinforced their comment that the core problem is misalignment between on-peak demand hours and on-peak energy hours, which makes load management more challenging, and that utilities typically align these periods. He shared a chart shown in Appendix B from a prior ICG rate study comments illustrating the mismatch and suggested that the peak hours could be narrower, better matching actual system peak timing, rather than broad bands applied across months. Devin confirmed he understood Jeffry's two points, lack of alignment, and the opportunity to narrow the peak windows, and said he appreciated the feedback.

Devin expanded on the interruptible L-25 I rate, describing it as structurally similar to L-25 but with a reduced demand charge reflecting system value from curtailment and the ability to impose incremental pricing during high-cost periods. He explained the demand credit methodology, based on avoided costs of a combustion turbine, using an LMS 100 CT with IRP-based assumptions, converting installed cost to annual fixed cost per kW, including debt service, fixed O&M, and tax-related components to produce a per kW year value that becomes the demand credit. He also described interruptible operations, including physical curtailments during emergencies, up to 250 hours of economic curtailments, and the option for customers to buy through at incrementally priced secondary power.

- Jeffry requested greater visibility into how incremental secondary or economy power prices are estimated, ideally with day-ahead information or a customer-accessible portal that would let participants see market conditions and plan whether to buy through or curtail. Devin noted that Jeffry wanted better day-ahead transparency and that it could help both sides if customers shared plans earlier. Jeffry agreed and added that the interruptible credit calculation should also account for reserve margin requirements, noting that serving firm load requires building additional capacity beyond load and that the credit should reflect that. Devin acknowledged that Jeffry had provided supporting materials in prior comments and said they would be reviewed ahead of any future rate study, noting there is no formal date but that a forecasted 2027 deficit implies rate study timing could be within 2026, and that the working group is meant to get ahead of issues before that process starts.

Devin then moved to economy power rates, explaining EP as lower reservation charges in exchange for greater energy price risk, and distinguishing EP regular, with transmission only in the reservation charge, from EP optional, which includes some production costs and mixes average off-peak pricing with marginal on-peak pricing. He walked through the derivation of the reservation charge from transmission revenue requirement elements, noted the large increase driven by higher transmission costs, and described how Santee Cooper reduced the proposed increase after customer feedback to cap overall bill impacts. Devin explained that EP and EPO charge reservation on contracted load, that on-peak energy is marginal and hourly, with adders for fixed generation and capital improvement fund, and that prices are provided to customers without later true-ups. He also emphasized that marginal revenues above average cost are passed back to customers, lowering average fuel costs for those on average-priced service. He summarized the trade-off across interruptible, EPO, and EP: lower demand or reservation charges paired with increasing exposure to marginal energy pricing. Finally, Devin noted that EPO includes defined marginal hours and allows Santee Cooper to call additional on-peak hours under criteria recently changed from load-based to price-based. He then asked Jeffry to raise his questions about those additional on-peak events.

- Mike Lavanga raised concerns about increases to EP and EPO reservation charges, noting that while non-firm rates remain attractive due to lower demand charges, higher reservation charges erode that value. He questioned the rationale for significant transmission-related increases, given the non-firm nature of the rates, and cautioned that further increases could undermine customer participation and broader system benefits. Devin Ritter acknowledged the concern and invited further feedback on non-firm rates.
- Jeffry Pollock focused on transparency and risk predictability in EPO and L-25 tariffs, arguing that current triggers for additional on-peak hours and economic curtailments are vague and difficult for customers to plan around. He proposed linking triggers to clearer operational metrics, such as reserve margins or peak-demand thresholds, and suggested replacing fixed-price triggers with dynamic, market-based signals that better reflect real system conditions. Stewart clarified that the core request was improved ability for customers who are assuming risk to forecast, which Jeffry confirmed, emphasizing that customers are willing to take risk but want clearer definitions of what that risk entails. Devin acknowledged the feedback and noted its consistency with prior comments from the rate study.
- The conversation then turned to the demand sales adjustment. Devin explained how non-firm and non-class revenues are passed back to firm customers to reduce fixed-cost recovery requirements, highlighting that base rates are set assuming zero non-firm sales and credits flow automatically as

those sales occur. Jeffry and Mike both argued that certain interruptible customers, particularly L-25-I contribute to production costs through demand charges and therefore should receive some share of the demand sales adjustment. Devin clarified that interruptible customers receive credits tied to other non-firm and off-system sales, but not to their own production-demand revenues, and that growing interruptible load reduces the effective credit. Jeffry later raised concerns about the fuel adjustment clause, noting that purchase power and gas transportation costs, including implicit capacity components, are recovered volumetrically, which can distort cost allocation. Devin responded that explicit demand charges are excluded but agreed that implicit capacity costs are not currently distinguished, recognizing the issue as valid feedback for further consideration.

Open Discussion and Closing Remarks
– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart acknowledged the meeting's engagement, with substantial questions and comments. He asked whether there were any additional comments people wished to make. Hearing none, Stewart expressed appreciation to the team for the quality of the questions and observations they had offered.

Commitments and Next Steps

ACTION ITEM – noted during the meeting discussion

1. Santee Cooper to review and consider comments from Jeffry Pollock as part of the last rate study

   [Additional Industrial Rate design discussion topics:
   - L-25 TOU Periods
   - Events triggering additional on-peak hours/off-peak demand hours
   - Transparency in estimated Secondary/Economy Power incremental energy costs
   - FAC: recovery of third-party/imputed Demand charges, gas transportation costs
   - rate 25-LL: availability provisions]

Next Steps:

- 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 /ALTERNATE	January 20th ATTENDEES
Aalberts	**James Sturgeon**	
Central Electric Power Cooperative (Central)	Cole Price **Heather Zrust** John Becker	Heather Zrust
Century Aluminum	**Stephen Thomas**	Stephen Thomas
Heidelberg Materials (formerly SEFA)	**Stephen Zasmimovich**	
Ineos	**Brian Bach**	Brian Bach
Matheson	Audie Bremer	
Nucor	Bradley Powell **Mike Lavanga**	Bradley Powell Mike Lavanga
Pollock, Inc.	Jeffry Pollock **Jonathan Ly**	Jeffry Pollock Jonathan Ly
SC Department of Consumer Affairs (SCDCA)	**Jake Edwards** Roger Hall	Jake Edwards
[SC] Office of Regulatory Affairs	**Shayne Hyatt**	Shane Hyatt
Southern Alliance for Clean Energy (SACE)	**Eddy Moore**	
Also in Attendance		
JW Aluminum	Ronke Akano	Jennifer Franzone Matt Templeton
Metglas Inc.	Jerry Smith	Jerry Smith

**Members listed in alpha order by organization*

Santee Cooper Rates	Greg McCormack Devin Ritter Jack Grooms Kristin Bennett	Greg McCormack David London Devin Ritter Elijah Lowe Jack Grooms Kirstin Bennett John Calhoun Zachary Smith
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

APPENDIX B

Outside Materials

Table 3

Rate L-25 On-Peak Demand and On-Peak Demand and Energy Hours

Hour Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12:00 AM												
1:00 AM												
2:00 AM												
3:00 AM												
4:00 AM												
5:00 AM	DE	DE	D	D						D	DE	DE
6:00 AM	DE	DE	D	D						D	DE	DE
7:00 AM	DE	DE	D	D						D	DE	DE
8:00 AM	DE	DE	D	D						D	DE	DE
9:00 AM	DE	DE	D	D						D	DE	DE
10:00 AM												
11:00 AM												
12:00 PM												
1:00 PM					D	DE	DE	DE	D			
2:00 PM					D	DE	DE	DE	D			
3:00 PM					D	DE	DE	DE	D			
4:00 PM					D	DE	DE	DE	D			
5:00 PM					D	DE	DE	DE	D			
6:00 PM	D	D	D	D	D	DE	DE	DE	D	D	D	D
7:00 PM	D	D	D	D	D	DE	DE	DE	D	D	D	D
8:00 PM	D	D	D	D	D	DE	DE	DE	D	D	D	D
9:00 PM	D	D	D	D	D	DE	DE	DE	D	D	D	D
10:00 PM	D	D	D	D	D	DE	DE	DE	D	D	D	D
11:00 PM												

D	On-Peak Demand Hours.	Highest Winter Peak Hours
DE	On-Peak Demand and Energy Hours.	Highest Summer Peak Hours