



**SOUTHWEST POWER POOL, INC.
COST CONTROL & ALLOCATION REVIEW & EVALUATION TEAM**

March 3, 2026
1:30 PM – 5:00 PM CT

March 4, 2026
8:00 AM – 12:00 PM CT

Westin Galleria | Dallas, TX

SUMMARY OF MOTIONS AND ACTION ITEMS

ACTION ITEMS

1. Staff to provide a report to the CARE Team on the MISO connection points for both the north and south.
2. CARE Team to provide any objections via email to Steve, Kayla, and Kim if opposed to the recommendation to approve the Cost Containment Work Plan and support advancement and implementation of the identified recommendations through SPP staff initiatives and the applicable stakeholder processes.
3. Add discussion on accountability measures for the developer agreement to a future agenda.



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MINUTES

1. WELCOME

Co-Chair Kayla Hahn (MOPSC) called the meeting to order at 1:31 pm CT and welcomed everyone.

2. ADMINISTRATIVE ITEMS

a. Approval of Minutes

A motion to approve the minutes was made by Kevin Gunn (Evergy) and seconded by Randel Christmann (NDPSC). A motion to amend was then made by Stacey Burbure (AEP) and seconded by Steve Wright (SPP Board). The amendment was approved by voice vote with no opposition or abstentions. No further discussion occurred on the original motion, and it subsequently passed by voice vote with no opposition or abstentions.

3. CARE OVERVIEW

a. Workplan

Co-Chair Steve Wight (SPP Board) indicated that the CARE workplan would be updated based upon the survey responses. Mr. Wright also encouraged members of the SPP Regional State Committee to participate in the survey.

4. 765 KV OVERLAY STUDY PLAN

Casey Cathey (SPP) provided Staff's perspective on how to address the 765 kV overlay and how this approach aligns with the CARE team's effort to evaluate the full Extra High Voltage (EHV) overlay in a holistic manner. This evaluation includes projects already approved for construction, projects identified in the 2025 Integrated Transmission Plan (ITP), and those being considered in the 2026 ITP. Mr. Casey confirmed that the plan would include transmission lines above 345kV and all pertinent facilities. Chuck Hutchison (NPRB) asked about coordination with MISO. An action item was established for Staff to provide an update regarding potential optimization with MISO connection points for the north and south. Mr. Casey indicated a plan to provide projected cost of the ITP overlay at the next CARE Team meeting in April.



5. COST ALLOCATION

a. Cost Allocation Rubric

Sarah Bockelmann (SPP) introduced a proposed process to help narrow the list of potential options using a structured approach intended to provide a consistent and transparent method for evaluating proposals. Ms. Bockelmann outlined a three-step evaluation process that included guiding principles, evaluation rubric, and a comprehensive comparative analysis. Stakeholder feedback and survey responses will be collected to refine the rubric and ensure it effectively supports the evaluation process in an unbiased manner.

b. Traditional Cost Allocation Methodology Alternatives

Charles Locke presented an overview of existing transmission cost allocation and cost assignment methodologies that may inform the CARE Team's evaluation of future policy options. The presentation reviewed four primary approaches: load-ratio-share methods, financial-benefit methods, power-flow/impact methods, and individual assignment mechanisms. Much of the discussion focused on load-ratio-share approaches, including coincident peak, energy usage, blended peak-energy formulas, forecast-based allocation, and baseline-plus-incremental load structures. Coincident peak was noted for its simplicity and strong precedent, while energy-based methods better reflect system usage beyond peak periods. Hybrid and forecast-based approaches may better align costs with load growth and address stranded-cost risk, but they introduce greater complexity and uncertainty.

The presentation also reviewed financial-benefit approaches, such as adjusted production cost and balanced portfolio methodologies, which link costs to modeled economic benefits but rely heavily on assumptions and modeling inputs. Power-flow or impact-based methods were discussed as engineering-based approaches that trace system usage but can become complex and contentious when broadly applied. Finally, the discussion covered individual assignment and stranded-cost protection tools, including direct assignment, load-contribution charges, financial security requirements, and minimum charges, which are intended to protect existing customers from costs associated with large new loads. Participants noted that while the overview was helpful, further analysis is needed to compare the methodologies and evaluate tradeoffs as the CARE Team considers approaches that support both long-term transmission planning and the near-term challenges of rapidly growing large loads.

c. Large Load Discussion

i. Attachments AX/AQ/BA/BC Overview

This item was skipped due to time constraints.

ii. GRID-L Concepts/Framework/Principles



Sunny Raheem presented large load cost allocation options, outlining guiding principles and introducing the GRID-LL framework for addressing transmission costs associated with large load growth such as hyperscale data centers. The presentation highlighted a key structural challenge: transmission assets are built to last 40–60 years, while many large loads may operate for only 5–15 years, creating potential stranded-cost risk if those loads depart after transmission investments are made. The discussion focused on balancing protection for existing customers with maintaining economic development opportunities and efficient regional planning.

Three conceptual policy models were introduced. Option 1 would require an upfront financial commitment from the transmission customer serving the large load to hedge stranded-cost risk. Option 2 would modify existing cost allocation by incorporating an incremental load component, shifting more cost responsibility to areas experiencing higher load growth. Option 3 would combine these approaches through a hybrid structure. Discussion also highlighted policy considerations including how to define large load, how costs flow through utilities to end customers, avoiding double charging, and ensuring the framework does not discourage new load development while protecting existing ratepayers.

6. COST ALLOCATION SURVEY

Co-Chair Wright moderated a survey to garner feedback and gauge direction on cost allocation methodologies. The polling was intended to stimulate discussion, not serve as a final decision. The results of the survey are provided as an attachment to the minutes. Casey Cathey encouraged members to provide additional feedback at care@spp.org.

Question 1: With what you know today would you prefer that costs for the EHV overlay are allocated based on: (choose 1):

CARE + 3 RSC	18	
Hybrid	10	56%
Beneficiary Pays	5	28%
Highway/Byway	3	17%

Polling results indicated that a hybrid cost allocation approach received the greatest support among participants, with 56% selecting this option. Twenty-eight percent preferred a beneficiary-pays approach, while 17% supported retaining the existing Highway/Byway framework. The results suggest that a majority of participants are interested in exploring modifications to the current approach rather than maintaining the existing methodology without changes.

Discussion focused on clarifying how the different options should be interpreted. Participants noted that the Highway/Byway model represents the current regional approach, which allocates costs broadly across the region and relies on the principle that benefits are roughly commensurate over time. In contrast, a beneficiary-pays approach would apply a more granular methodology, potentially identifying beneficiaries at the project or portfolio level



through financial or system-impact analysis. Several participants suggested that a hybrid approach could build on the existing framework while incorporating targeted modifications, allowing the region to preserve elements of the current structure while adapting it to address emerging transmission needs.

Participants also discussed questions related to scope and beneficiary definition, including whether potential changes would apply broadly to the cost allocation framework or specifically to EHV overlay facilities and associated projects above 345 kV. Some participants noted that large load growth and transmission cost allocation issues may ultimately need to be addressed together, as both influence how transmission investments are planned and funded. Overall, the discussion suggested interest in exploring potential modifications to the current framework while continuing to evaluate how different approaches could be applied within SPP’s planning and cost allocation processes.

Question 2: What should be the primary objective of any revised transmission cost allocation methodology? (select up to 2):

CARE + 3 RSC	35	
Improve alignment between cost responsibility and measurable benefits	14	40%
Increase regional cost stability and predictability (bill impact predictability)	2	6%
Ensure fairness across states/zones/utilities	8	23%
Maintain simplicity, defensibility, and transparency	10	29%
Improve adaptability to future grid conditions	1	3%

Discussion suggested that many participants viewed cost-benefit alignment and fairness as closely related concepts, with several noting that fairness is often achieved through aligning costs with measurable benefits or cost causation. Participants also emphasized the importance of defensibility, particularly the ability to clearly explain and justify the methodology before regulators, legislators, and other stakeholders. Others noted that while fairness is important, it should not be interpreted as requiring identical benefits for all zones, but rather ensuring that no region experiences disproportionate cost burdens.

Participants also discussed the importance of simplicity and transparency, noting that the current methodology has been relatively easy to explain to policymakers and stakeholders. Some cautioned that more complex analytical approaches could become difficult to communicate or defend publicly. Additional comments highlighted the need for a methodology that supports long-term grid development and economic growth, while ensuring that cost allocation does not discourage necessary transmission investment. Overall, the discussion reflected broad agreement that any revised framework should balance fairness, cost-benefit alignment, simplicity, and regulatory defensibility.



Question #3: Should cost allocation be guided by a minimum benefit threshold (no-losers) or equity across states or zones? (select 1):

CARE + 3 RSC	17	
Minimum benefit threshold	8	47%
Balanced outcome	2	12%
Hybrid approach	7	41%

During the discussion, participants considered whether transmission cost allocation should continue to rely on SPP’s current minimum benefit threshold (“no-loser”) framework, under which each zone must achieve at least a minimum benefit-to-cost ratio, or move toward an alternative approach that more evenly distributes benefits and costs across the region. Under the alternative concept, some stakeholders suggested that zones receiving comparatively higher benefits from transmission investments could bear a greater share of costs, while zones receiving fewer benefits would pay less.

Participants expressed differing perspectives on these approaches, and the discussion reflected roughly divided views between maintaining the current minimum benefit threshold methodology and exploring a hybrid approach that could incorporate elements of both the existing framework and more balanced benefit distribution.

Question #4: What are the primary strengths of the current framework? (select up to 3):

CARE + 3 RSC	49	
Simple, easy to understand	13	27%
Aligns cost with geographic benefit.	0	0%
Enables Regional backbone development.	8	16%
Reduces litigation & modeling complexity.	12	24%
Supports reliability and resilience.	5	10%
Improves Financeability & Development clarity.	3	6%
Encourages Long-term planning vs incremental fixes.	8	16%

Participants discussed the perceived strengths of the current transmission cost allocation framework, with polling results indicating strong support for its simplicity, transparency, and ability to support regional transmission development. Several participants noted that the current framework is relatively easy to understand and administer, which helps reduce the risk of disputes or litigation. At the same time, the polling results indicated limited support for the view that the existing framework successfully aligns costs with geographic benefits, suggesting concerns about how well costs and benefits are distributed under the current approach.

Several participants commented that while aligning costs with geographic benefits may be desirable, no cost allocation methodology will perfectly match costs and benefits. Some participants expressed support for maintaining elements of the current Highway/Byway framework due to its simplicity and durability, while acknowledging that improvements may still be warranted. Others noted that modifying the framework could introduce modeling complexity and implementation challenges. Overall, the discussion reflected differing



perspectives on whether the current framework should be preserved for its stability and transparency or adjusted to better align costs with geographic benefits, with some participants suggesting that targeted or one-time approaches may provide a balanced path forward.

Question #5: What are the most significant limitations of the current framework as it applies to new transmission projects? (select up to 3):

CARE + 3 RSC	33	
Does not capture economic/market usage benefits	6	18%
Creates potential inequities among zones/states due to large, lumpy investments.	13	39%
Timing of transmission overlay investments means some states/zones will receive delayed benefits compared to earlier projects.	12	36%
Insufficient cost discipline/accountability due to costs being regionalized.	2	6%

Participants discussed several potential limitations of the current transmission cost allocation framework. Discussion reflected differing perspectives on these results. Some participants indicated that these issues should be viewed less as limitations and more as natural characteristics of a large regional transmission system. Others suggested that the framework could better capture system usage—such as through energy-based allocation—and that aligning costs more closely with portfolio-specific beneficiaries may increase support for transmission investments. Participants also noted that additional data and modeling may help evaluate the impacts of potential changes, and some raised questions about whether the current framework adequately reflects the costs of delay or inaction, particularly given that large transmission overlays have been considered previously but not implemented.

Question #6: Should SPP continue to rely primarily on regional cost sharing for 345 kV+ facilities? (select 1):

CARE + 3 RSC	18	
Yes — retain strong regional sharing	4	22%
Balanced regional + localized approach	2	11%
Shift toward more beneficiary/usage driven	10	56%
Shift to more localized cost allocation for high-voltage overlays until their benefit-to-costs are better understood.	1	6%
No strong view	1	6%

Polling results showed that a majority of participants favored shifting toward a more beneficiary- or usage-driven cost allocation approach for EHV overlay facilities, while a smaller group supported retaining strong regional sharing or using a more balanced regional and localized framework. Discussion reflected interest in preserving key strengths of the current Highway/Byway approach while refining the methodology to better account for system usage, geographic benefit, and the scale of future transmission investment. Several participants suggested that a hybrid approach may ultimately be appropriate, combining regional cost



sharing with more targeted usage- or benefit-based allocation signals, including possible energy-based components.

Participants also discussed whether any revised approach should be a one-time methodology for the current EHV overlay buildout or a long-term framework for future projects. Some stressed the importance of maintaining durability and avoiding frequent changes to cost allocation from portfolio to portfolio, particularly for states directly affected by early 765 kV projects. Others emphasized that while the methodology itself should be stable, the results may appropriately change over time as usage and benefits evolve. Additional discussion focused on the difficulty of forecasting long-term benefits, the potential value of a look-back mechanism, the importance of ex ante cost allocation under FERC policy, and whether some portion of cost recovery should be based on energy usage rather than solely on 12 coincident peak demand.

Question #7: For EHV loads, SPP should:

CARE + 3 RSC	18	
Stay with demand charge only	1	6%
Use and energy charge only	0	0%
Use a combination of energy and demand charge	17	94%

Polling results showed overwhelming support for using a combination of energy and demand charges for EHV loads, with 94% of respondents selecting that option and only 6% favoring retention of a demand-charge-only approach. No participants supported using an energy charge only. Based on the strong consensus reflected in the polling, discussion on this question was limited.

The co-chairs noted that the results provide clear direction to continue evaluating a framework that adds an energy-based component to the existing demand-based structure for EHV loads.

Question #8: If we use Beneficiary Pays model, in whole or in part, what should the focus be on?

CARE + 3 RSC	1st place	2nd place	3rd place
Load Ratio Share	14	1	3
Financial Benefit	2	6	6
Power Flow Impact	2	7	5

Polling results indicated that Load Ratio Share (LRS) was the most frequently ranked first-choice approach among participants, followed by Power Flow Impact analysis and Financial Benefit modeling. While LRS received the strongest first-place preference, discussion suggested that views across the group remained somewhat divided, with several participants noting that the results may reflect familiarity with LRS rather than a definitive preference to abandon the other analytical approaches.



Participants discussed the relative strengths and limitations of the different methodologies. Some noted that power-flow analysis reflects the physical operation of the system and could be evaluated after projects are placed in service, potentially serving as a useful verification or “look-back” mechanism. Others emphasized that load-ratio-share approaches are based on measurable system usage, such as coincident peak or energy consumption, and may be simpler to implement than complex financial modeling. Several participants suggested that the group should not prematurely eliminate either power-flow or financial-benefit approaches, as each could provide useful insights into transmission usage and benefit distribution.

Discussion also highlighted the need for additional clarity and examples to better understand how these methodologies would operate within a beneficiary-pays framework. Some participants noted that the question may require further refinement, particularly regarding how load-ratio-share approaches could incorporate demand, energy usage, or incremental load growth metrics. Overall, the group acknowledged that further analysis and discussion will be required before narrowing the set of methodologies under consideration, and staff requested that participants provide additional questions or examples to help guide future evaluation of these approaches.

Question #9: If we use an Assignment to Individual Entities to protect against stranded cost, which option would you prefer?

CARE + 3 RSC	17	
Directly Assigned	0	0%
Load Contribution	0	0%
Minimum Charge	0	0%
Posting of Financial Security	1	6%
Safe Harbor Cost Limit	2	12%
Combination of above	14	82%

Polling results showed strong consensus that a combination of tools would be preferred to address stranded cost risk. Discussion indicated that participants generally viewed stranded-cost protection as requiring multiple complementary mechanisms, as different tools may address different types of risk. For example, some mechanisms provide upfront financial assurance, while others offer ongoing protection over time as system usage evolves. Participants noted that additional work will be required to determine the appropriate mix of tools and how they should be applied within SPP’s planning and cost allocation framework.

Question #10: What level of analytical support should inform cost allocation decisions?:

CARE + 3 RSC	18	
Detailed quantification of both reliability and economic benefits	3	17%
Strong analytical support, with room for policy adjustments where benefits are difficult to quantify	12	67%
Directional analysis, without attempting precise benefit measurement	3	17%



Structural decision primarily guided by policy principles rather than detailed modeling.	0	0%
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Polling results indicated strong support for using strong analytical support while maintaining flexibility for policy adjustments. Sixty-seven percent of participants selected the option supporting strong analytical analysis with room for policy judgment where benefits are difficult to quantify. Smaller groups favored either detailed quantification of both reliability and economic benefits (17%) or directional analysis without precise benefit measurement (17%). No participants supported making cost allocation decisions based primarily on policy principles without analytical support.

Discussion suggested that participants generally favor an approach that combines analytical rigor with practical policy flexibility, recognizing that some transmission benefits—particularly reliability, resilience, and long-term regional value—may be difficult to quantify precisely. Participants noted that the results provide clear direction that analytical analysis should play a central role in informing cost allocation decisions while still allowing policy considerations to guide final determinations where modeling limitations exist.

Question #11: What additional information is needed before narrowing to a final recommendation? (select up to 3)

CARE + 3 RSC	47	
Comparative analysis of other RTO models	0	0%
Bill impact analysis by zone/state	7	15%
Historical benefit distribution analysis	2	4%
Future scenario modeling	15	32%
Legal/regulatory risk assessment	6	13%
Implementation complexity assessment	12	26%
Stakeholder acceptance outlook	5	11%

Polling results indicated that participants would like additional analysis in several key areas before moving toward a final recommendation. Participants also noted several specific analytical needs. Some emphasized the importance of evaluating how an energy and demand charge structure would be designed, including determining an appropriate balance between energy-based and demand-based cost recovery rather than relying on a simple 50/50 split. Others requested additional clarity from staff on implementation complexity, including how potential hybrid approaches could be integrated into existing planning and cost allocation processes. Staff indicated that the results of this question will help guide where analytical efforts should be focused as the CARE Team continues refining potential policy recommendations.

7. 1.0 VS 1.25 BENEFIT COST RATIO DISCUSSION

Brooke Keene (SPP) presented background on the use of the benefit-cost ratio for economic projects in response to a workplan item considering whether to increase the requirement to 1.25. Staff also reviewed the position of the Federal Energy Regulatory Commission (FERC).



Staff noted that increasing the requirement would likely have little practical impact, as no economic project with a benefit-cost ratio below 1.25 has ever been issued.

Staff recommended assigning an action item to the Economics Studies Working Group and the Cost Allocation Working Group to reconsider the current 1.0 benefit-cost ratio requirement for economic projects and report back to the CARE Team, as applicable. There was no opposition to this recommendation. However, Tyler Huebner (Google) expressed concern that projects with benefit-cost ratios between 1.0 and 1.2 could potentially be excluded and noted that he would need additional time to study the issue further.

8. COST CONTAINMENT

a. Workplan

Due to time constraints this item was skipped. Co-Chair Wright requested the CARE Team review the material and provide any objections via email to Steve, Kayla, and Kim if opposed to the recommendation to approve the Cost Containment Work Plan and support advancement and implementation of the identified recommendations through SPP staff initiatives and the applicable stakeholder processes.

b. Cost Estimate Comparison

Due to time constraints, this item was skipped but is provided in an appendix to the presentation.

c. Order 1000 Task Force Recommendation (Agreement)

Paul Suskie (SPP Staff) provided an update on the recommendation to create a developer agreement for projects awarded through a competitive process. The agreement would then be converted into a formal contract and filed with FERC. The proposal has been posted and is currently available for review. Steve Gaw (APA) noted legal issues associated with his approach that will likely require additional work and requested additional information regarding accountability measures be incorporated. Co-Chair Wright agreed to add this topic to a future agenda.

9. ACTION ITEM REVIEW

- Staff to provide a report to the CARE Team on the MISO connection points for both the north and south.
- CARE Team to provide any objections via email to Steve, Kayla, and Kim if opposed to the recommendation to approve the Cost Containment Work Plan and support advancement and implementation of the identified recommendations through SPP staff initiatives and the applicable stakeholder processes.
- Add discussion on accountability measures for the developer agreement to a future agenda.

10. NEXT STEPS

The next CARE Team meeting will be held on Monday, April 13, 2026 in New Orleans, LA.



11. ADJOURNMENT

The meeting was adjourned at 11:47 a.m. CT.