COST CONTROL & ALLOCATION REVIEW & EVALUATION TEAM MEETING
May 6, 2026
7:00 a.m. – 4:00 pm MT
The Clyde Hotel | Albuquerque, NM

SUMMARY OF MOTIONS AND ACTION ITEMS

Motions

The CARE Team approves the meeting minutes from April 13, 2026. Randel Christmann (NDPSC) motioned/Stuart Soloman (SPP Board) seconded. *The motion passed unanimously*.

Action Items:

1. SPP Staff to review the Public Utility Commission of Texas Performance Monitor Report and provide an update at the June meeting regarding SPP activities.
2. Follow up with the RSC regarding subregions and deliverability areas and return with additional discussion at the June meeting.
3. Basin and SPS to provide a report at a future meeting on large load growth and associated tariff considerations.
4. CARE Team members to review the ATRR presentation and provide any questions or feedback to leadership for further consideration.

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MINUTES

Agenda Item 1 – CALL TO ORDER

Chair Kayla Hahn called the meeting to order at 8:02 a.m. MT and welcomed everyone.

Agenda Item 2 – ADMINISTRATIVE ITEMS

MOTION: The CARE Team approves the meeting minutes from April 13, 2026. Randel Christmann (NDPSC) motioned/Stuart Soloman (SPP Board) seconded. *The motion passed unanimously.*

Agenda Item 3 – COST ALLOCATION

A. Current Highway/Byway (Subregional) Approach

Charles Locke (SPP Staff) provided a refresher on the Highway/Byway cost allocation methodology, with particular focus on the "Byway" component and how it relates to potential hybrid regional and subregional cost allocation concepts under discussion. Discussion emphasized that the existing 100–300 kV structure could serve as a model for a hybrid regional/subregional allocation approach being evaluated through the stakeholder survey process. Staff noted that while the existing framework currently uses a 67/33 split, the percentages could be modified if stakeholders pursue alternative allocation structures. Several illustrative examples were presented to demonstrate how load ratio share and subregional allocation impact customer costs.

B. Potential Cost Allocation under Load Scenarios

Charles Locke and Don Frerking (SPP Staff) presented illustrative cost allocation scenarios based on a hypothetical $10 billion transmission portfolio to evaluate allocation methods and resulting revenue requirements. The analysis focused on years five and ten and used SPP's regulatory forecast model, with results expressed in total revenue requirements as well as per-megawatt and per-kilowatt-hour cost metrics by sub-region. The scenarios included the base ITP load forecast, a slower growth scenario, and a no-growth scenario. Allocation methods examined included a peak-based approach, a 50/50 peak-and-energy

approach, and a byway-style allocation reflecting a 67/33 subregional/regional split. The byway analysis required simplifying assumptions about the geographic distribution of transmission investment across sub-regions.

Staff clarified that the portfolio is entirely hypothetical and intended to illustrate comparative impacts across allocation methods rather than represent an actual project. It was noted that the results are highly sensitive to assumptions about load growth timing, location of new load, and the assumed geographic placement of transmission assets. The group discussed how allocation outcomes vary depending on whether peak-only or hybrid peak-and-energy methods are used. While differences between methods were generally modest in percentage terms, participants noted that shifts in load forecasts and sub-regional load growth patterns can materially affect allocation outcomes. Discussion also highlighted that incorporating an energy component in allocation better reflects annual system usage trends and can complement peak-based methodologies. Participants noted that energy-based measures may better capture evolving load characteristics, particularly with increasing large-load and data center growth, while also improving alignment with planning and economic analysis processes.

Agenda Item 4 – LARGE LOADS

A. GRID-L

Sunny Raheem (SPP Staff) discussed the GRID-L mechanism to address stranded cost risk and ensure large loads pay charges reflecting their transmission system impacts. Mr. Raheem outlined four potential approaches for applying GRID-L costs: threshold-based, impact-based, portfolio-based, and customer-type-based methodologies. Discussion focused on the tradeoffs among fairness, implementation complexity, and customer incentives. Participants emphasized the importance of clearly defining implementation scope, responsible payers, and stranded cost concepts. The group discussed mechanisms for managing GRID-L risk exposure, including upfront deposits, ongoing charges, and hybrid approaches. Participants stressed the importance of coordinating GRID-L charges with existing transmission rates and tariff structures to avoid double charging.

Agenda Item 5 – COST ALLOCATION POLL

Prior to administering the poll, Chair Wright confirmed that polling responses do not represent official positions and may change as discussions continue, and participants are not bound to their polling responses or positions reflected during the discussion.

1. **For cost allocation purposes, do you prefer:**

Options	Number of Votes	Percentage
A - A regional-only approach – costs would be borne by the entire region	5	33%
B - A subregional/deliverability areas-only approach – costs would be borne by the subregions/deliverability areas	1	10%
C - Both regional and subregional/deliverability areas, where costs would be shared between the region and subregions/deliverability areas	9	60%

2. **If costs were allocated on a blended basis between the region and the subregions/deliverability areas, would you prefer:**

Options	Number of Votes	Percentage
A - The region pays a minority share, and the subregions/deliverability areas pay a majority share	6	40%
B - The region and subregions/deliverability areas split costs equally	1	7%
C - The region pays a majority share, and the subregions/deliverability areas pay a minority share	8	53%

Staff and members agreed that further analytical work is needed to develop a more robust framework to support cost allocation design decisions.

3. **If costs are allocated on a blended basis between the region and sub-region should there be an allocation to the sub-regions based on proportion of EHV transmission investment within each sub-region similar to the current allocation for 100-300kv transmission?**

Options	Number of Votes	Percentage
A - Yes	9	60%
B - No	6	40%

Some participants expressed concern that a subregional allocation could move away from a fully regional perspective of backbone transmission, which is viewed by some as a shared regional asset supporting the RTO structure. Supporters noted that using transmission investment as an allocation proxy may help mitigate risks associated with forecasted load that does not fully materialize and improve alignment between cost responsibility and actual system development. Staff also emphasized that leveraging existing methodologies would promote simplicity and ease of implementation. Concerns focused on whether a subregional allocation framework could fragment the regional nature of backbone

facilities, as well as questions regarding the clarity of the proposal and how transmission investment should appropriately function as a cost allocation basis.

4. **If costs are allocated on a sub-regional basis do you believe there should be a lookback mechanism after x number of years to evaluate whether the sub-regional allocation should be eliminated?**

Options	Number of Votes	Percentage
A - Yes	10	67%
B - No	5	33%

The group discussed the potential implementation of a look-back mechanism to periodically evaluate and modify subregional allocations for new infrastructure developed under the Highway/Byway framework. Discussion reflected differing perspectives on balancing flexibility and long-term stability in allocation policies. Some participants raised concerns that frequent reevaluation could create instability or disadvantage certain subregions over time. Others suggested that incorporating an energy charge into the allocation structure could reduce the need for a formal look-back process. Additional comments emphasized a preference for avoiding mandatory recurring reviews in order to maintain predictability and stability in the allocation methodology. The group clarified that any potential look-back mechanism would apply only to the EHV overlay.

5. **Given the examples provided at the most recent meeting, for costs allocated across the entire region, do you prefer:**

Options	Number of Votes	Percentage
A - Load Ratio Share with 12CP only	3	20%
B - Load Ratio Share with 12CP and Energy	12	80%

6. **If costs were allocated between the region and the subregions/deliverability areas, would you prefer:**

Options	Number of Votes	Percentage
A - To model reliability benefits (if feasible) at the regional level to quantify the regional portion	8	53%
B - To assume reliability benefits at the regional level	7	47%

The group discussed whether reliability benefits should be explicitly modeled at the regional level to determine the regional share of cost allocation or whether those benefits should be assumed without detailed analysis. Participants acknowledged the complexity and potential inaccuracies associated with modeling reliability benefits, resulting in differing views on the most practical approach.

7. **If costs were allocated on either a subregional/deliverability area approach or blended approach (some allocation at both the regional and subregional level/deliverability area levels), how should costs be allocated <u>within</u> the subregion/deliverability area?**

	1st	2nd	3rd	4th	5th	6th
Economic Benefits (APC)	0	0	2	1	1	9
Load Ratio Share with 12CP only	2	2	1	2	5	2
Load Ratio Share with12CP and Energy	7	4	1	1	1	0
Economic Benefits (APC) and Load Ratio Share with12CP only	0	2	2	4	5	0
Economic Benefits (APC) and Load Ratio Share with12CP and Energy	4	4	2	4	0	0
Incremental coincident peak (12CP) and/or incremental energy	1	2	6	1	1	2

The group discussed challenges associated with incorporating APC benefits into allocation methods, particularly due to uncertainty in forecasting gas prices, weather, and load conditions. Concerns were raised about potential double-counting when combining APC with energy-based allocators. Participants noted that while APC can reflect regional economic and reliability benefits, its results are highly sensitive to assumptions. Energy was broadly viewed as a reasonable and more transparent proxy for economic benefits due to its simplicity and measurability. The group also discussed the need to balance analytical precision with explainability for stakeholders, particularly retail customers.

8. **If costs were allocated on a subregional or deliverability area basis, which do you prefer?**

Options	Number of Votes	Percentage
A - Subregional	3	21%
B - Deliverability Areas	8	57%
C - Either	3	21%

The group discussed differences between using deliverability areas and subregions for transmission cost allocation and noted that deliverability areas are not currently incorporated into the SPP tariff for cost allocation purposes and that implementing such an approach would require tariff revisions. Discussion also referenced the historical development of the existing five subregion structure, which resulted from prior stakeholder and political compromises rather than a purely deliverability-based framework. The group acknowledged the complexity of applying subregional allocation methodologies to large interstate 765 kV transmission lines that cross multiple zones and subregions. Participants agreed that additional discussion would be beneficial regarding whether deliverability areas or subregions provide the more appropriate framework for future allocation approaches. An action item was established to follow up with the

Regional State Committee (RSC) regarding subregion and deliverability area development and return with additional discussion at the June meeting.

9. Identify the definition and trigger: Which definition of large load should GRID-L use?

Options	Number of Votes	Percentage
B - Single site large load exceeding X MW	4	27%
C - Aggregated loads in a common industrial/commercial sector exceeding X MW (Concentration risk)	1	7%
D - Combination (Single site large load + aggregation)	10	67%

Participants noted significant growth in both data centers and gas/oil electrification, underscoring the importance of clearly defining large load categories for cost allocation purposes. Concerns were raised about establishing a new GRID-L specific definition given existing tariff definitions and ongoing external efforts, including NERC processes, and the need for alignment across planning, tariff, and regulatory frameworks. The discussion emphasized the need for consistency across definitions while balancing engineering practicality, regulatory alignment, and GRID-L policy objectives.

10. Upfront Commitment Structure: What level of upfront financial commitment should GRID-L require?

Options	Number of Votes	Percentage
A - Minimal (creditworthiness only)	1	8%
B - Moderate (financial security + minimum charge)	5	38%
C - Strong (direct assignment + financial security + minimum charge)	7	54%

Discussion clarified that requirements would be imposed on transmission customers, who would then be expected to pass associated costs through to retail load customers. Questions were raised regarding how these commitments would be implemented and collected in practice. The group acknowledged the importance of developing clear and effective mechanisms to address different types of stranded cost risks associated with large load growth.

11. For the EHV overlay, how much should GRID-L customers pay?

Options	Number of Votes	Percentage
A. Full incremental cost	7	50%
B. Partial cost, such as 50%	6	43%

C. Same as existing customers	1	7%

Participants clarified that incremental costs represent net costs after accounting for benefits provided to existing customers. The discussion also highlighted concerns regarding the potential for double charging and the need to balance appropriate cost recovery with fairness to stakeholders.

12. **Should a large load cost allocation policy apply to new large loads assumed in the 2024-2026 ITPs?**

Options	Number of Votes	Percentage
Yes	10	71%
No	4	29%

Discussion highlighted challenges associated with applying GRID-L charges to the 2024 and 2025 ITPs, particularly due to existing contracts and prior regulatory approvals. Several participants supported implementing GRID-L beginning with the 2026 ITP cycle to avoid reopening previously executed agreements. The group acknowledged the importance of clearly defining the scope and timing of GRID-L application to balance fairness, regulatory certainty, and practical implementation considerations.

13. **Please rank the following GRID-L applicability and assignment options in order of preference, where 1 indicates your most preferred option and 4 indicates your least preferred**.

	1st	2nd	3rd	4th
Threshold based	5	5	2	1
Impact-Based	2	3	4	3
Portfolio-Based (CPP-Aligned)	6	4	3	0
Assignment by load customer type	0	1	4	7

Agenda Item 6 – COST CONTAINMENT PROCESS FOLLOW UP

Kathleen Jackson (PUCT) provided an overview of Texas's approach to cost containment and project oversight for the 765 kV buildout, noting the framework was influenced by risk-management practices from the oil and gas industry. She emphasized the importance of clear processes, schedule discipline, stakeholder engagement, transparency, and accountability throughout project execution. Commissioner Jackson discussed Texas's use of an independent third-party monitor to provide detailed oversight, evaluate project data, develop performance metrics, and support consistent tracking of project outcomes. She noted the monitoring framework was designed to enable ongoing evaluation during project execution so issues could be identified early and corrective actions taken before significant cost or schedule impacts occur. She stated Texas is interested in continuing collaboration with SPP to share lessons learned and explore whether elements of the Texas monitoring approach could support SPP's transmission development and oversight efforts. An action item was established for Staff to review the material provided and provide a report at the June CARE meeting.

Agenda Item 7 – ACTION ITEM: COST CONTAINMENT – TO CONTRACTS

Paul Suskie (SPP Staff) reported that SPP Staff has been working with OG&E, SPS, and AEP on agreements related to directly assigned Short-Term Reliability Projects (STRPs) associated with the 765 kV buildout. Mr. Suskie stated the agreements would include cost containment measures, schedule guarantees, and in-service commitments. Mr. Suskie also referenced direction from the SPP Board of Directors for Staff to develop a broader stakeholder process to establish standardized agreements for STRPs going forward.

Agenda Item 8 – ACTION ITEM REVIEW

1. SPP Staff to review the Public Utility Commission of Texas Performance Monitor Report and provide an update at the June meeting regarding SPP activities.
2. Follow up with the RSC regarding subregions and deliverability areas and return with additional discussion at the June meeting.
3. Basin and SPS to provide a report at a future meeting on large load growth and associated tariff considerations.
4. CARE Team members to review the ATRR presentation and provide any questions or feedback to leadership for further consideration.

Agenda Item 9 – NEXT STEPS

SPP staff plans to develop draft recommendations incorporating group input and poll results for discussion and feedback at the June CARE meeting. The next CARE Team meeting is scheduled for June 15–16 in Chicago, Illinois.

Agenda Item 10 – ADJOURNMENT

The meeting was adjourned at 2:40 p.m. MT.