COST CONTROL & ALLOCATION REVIEW & EVALUATION TEAM MEETING
August 24, 2026
7:00 a.m. – 5:00 p.m. CT

Hilton Chicago O'Hare | Chicago, IL

SUMMARY OF MOTIONS AND ACTION ITEMS

Motions

MOTION: The CARE Team approves the meeting minutes from July 23, 2026. Commissioner Randy Christmann (NDPSC) motioned/Jeremy Severson (Basin) seconded. *The motion passed unanimously.*

Action Items:

1. 2026 ITP Portfolio: Staff will develop a 20-year comparison of APC to the Load Ratio Share.
2. Staff will circulate the recent HITT – C1 FERC Order and HITT-C2 district court decision to the CARE Team.
3. CARE Team members should submit comments on all "one-pagers" by September 4.

COST CONTROL & ALLOCATION REVIEW & EVALUATION TEAM MEETING
July 23, 2026
8:00 a.m. – 5:00 p.m. CT

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MINUTES

Agenda Item 1 – Call to Order

Chair Kayla Hahn (MOPSC) called the meeting to order at 7:03 a.m. CT and welcomed everyone. The following members were present or represented by proxy:

Chair Kayla Hahn, Missouri Public Service Commission (MOPSC)
Stacey Burbure, American Electric Power (AEP), *proxy Kate Daley*
Jason Chaplin, Oklahoma Corporation Commission (OCC)
Randel Christmann, North Dakota Public Service Commission (NDPSC)
Dennis Florom, Lincoln Electric System (LES)
Justin Grady, Kansas Corporation Commission (KCC)
Kevin Gunn, Evergy
Tyler Huebner, Google
Chuck Hutchison, Nebraska Power Review Board (NPRB)
Kathleen Jackson, Public Utility Commission of Texas (PUCT)
Jeremy Severson, Basin Electric Power (BEP)
Stuart Solomon, SPP Board of Directors (SPP Board)
Justin Tate, Arkansas Public Service Commission (APSC)
Jon Thurber, South Dakota Public Utilities Commission (SDPUC)
Michael Wise, Golden Spread Electric Cooperative (GSEC)

Steve Wright, SPP Board of Directors (SPP Board) was not present.

Agenda Item 2 – Administrative Items

A. Approval of Minutes

The July 23, 2026 meeting minutes were presented for approval. Tyler Huebner (Google) identified a minor typo on the minutes which will be corrected and reposted.

MOTION: The CARE Team approves the meeting minutes from July 23, 2026. Commissioner Randy Christmann (NDPSC) motioned/Jeremy Severson (Basin) seconded. *The motion passed unanimously.*

B. Review of Action Items

Kim O'Guinn (SPP) reviewed open action items from previous meetings.

C. Agenda Review

The agenda review was covered under agenda item 3.

Agenda Item 3 – CARE Roadmap

Kim O'Guinn (SPP) presented an updated roadmap and highlighted upcoming agenda topics.

Stuart Solomon (SPP Board) previewed two proposed principles and a survey question on the definition of large load. The first principle supports large loads paying incremental costs associated with their service, including a portion of interconnection and overall transmission portfolio costs, while generally protecting other customers from costs imposed by large loads. Members discussed the need to ensure that the cost-neutrality concept recognizes system and reliability benefits received by existing customers. The second principle addresses stranded cost protection by placing responsibility on transmission customers serving large loads if those loads do not materialize, reduce demand, or cease operations.

Agenda Item 4 – 2026 ITP Portfolio Overview & Initial Benefits

Sunny Raheem (SPP) presented an updated EHV overlay analysis, including Adjusted Production Cost (APC) savings and benefits related to reliability, transfer capability, load-serving capability, voltage support, and system losses. The 765 kV overlay alone produced an APC benefit-to-cost ratio above 1.25, while pairing the overlay with lower-voltage upgrades increased the estimated ratio to approximately 8:1. Staff emphasized that the analysis remains conservative and does not include formal ITPP reliability benefits.

Group members discussed customer impacts, project costs, alternative lower-voltage solutions, local generation, project timing, construction duration, and cost allocation. Staff noted that 95% of emergency-energy impacts were excluded from the benefits calculation to maintain a conservative analysis and that lower-voltage alternatives could require approximately $1–2 billion in additional upgrades.

Agenda Item 5 – Annual Transmission Revenue Requirement (ATRR) Scenarios

Don Frerking (SPP) presented an illustrative ATRR scenario analysis comparing various cost allocation methodologies for a hypothetical $35 billion full-system overlay. The analysis examined a 100% regional allocation, a 50% peak/50% energy allocation, and a 50% regional/50% deliverability area allocation under two in-service scenarios: full portfolio operation in 2035 and a three-year delay for the North portion. Results were presented on a unit-cost basis for 2035 and 2045, with differences driven by load-factor assumptions, deliverability-area loads, ATRR, inflation, depreciation, and assumed in-service dates. The analysis showed the North Deliverability Area experiencing the greatest impacts under deliverability-area allocation because of the relatively higher ATRR and lower load and energy levels in the area. Stakeholders discussed the importance of recognizing that projected in-service dates can change significantly and that the timing of transmission construction materially affects cost allocation outcomes.

The group revisited its prior survey on cost allocation and discussed potential cost-allocation approaches for the 765kV overlay, including regional, deliverability area, and hybrid methodologies. Members discussed a framework under which costs would initially be weighted toward the deliverability area where facilities are located, with greater regional allocation as benefits become more regionalized. The group discussed the possibility for an objective transition point or trigger, including a 50% deliverability area and 50% regional allocation, with the regional portion based on peak and energy. The discussion also addressed the treatment of existing 345 kV facilities and the need to consider cost allocation holistically. Discussion emphasized that any approach should be supported by technical and economic analysis and be defensible before FERC. Members also discussed the interaction with existing Highway/Byway cost allocation and GRID-C, including potential impacts during a transition period.

Agenda Item 6 – CARE Recommendations One Pagers

Chair Hahn highlighted the "one-pager" recommendations, including the Highway/Byway approach, regional/deliverability-area split, Coincident Peak (CP) & Energy, look-back mechanism, and benefit-to-cost ratio options. Members were asked to provide edits and feedback in advance of the September meeting, with the intent of voting on the proposals at that meeting.

Agenda Item 7 – Cost Allocation Large Load Framework

a. Load Interconnection Cost Responsibility/Large Load Show Cause

Charles Locke (SPP) presented a proposed delivery point safe harbor to address FERC's concerns regarding cost shifting if large loads fail to materialize. Under the proposal, network upgrades identified through the Attachments AQ, AX, or BA study processes would remain base plan funded up to a specified safe harbor limit, with costs above the limit directly assigned to the transmission customer. Directly assigned costs would be supported by financial security and used to reduce base-plan costs borne by SPP transmission customers. Staff noted that the approach could initially apply only to high-impact large loads (HILLs) as part of the anticipated November FERC compliance filing, with the option for the Regional State Committee to expand it to all delivery points later.

Members generally supported a delivery-point safe harbor consistent with the existing generation framework. Additional analysis is needed to establish the limit—potentially using historical costs, per-MW limits, aggregate limits, or a combination, and resolve financial security and load-materialization requirements. Staff will develop a Revision Request for stakeholder review consistent with the FERC Show Cause compliance timeline.

b. Load Materialization Risk Protection

Natasha Henderson (SPP) presented a framework to protect existing customers from cost shifts when forecasted load does not materialize, potentially assigning risk to the submitting transmission customer and using the higher of forecasted or actual load for billing. Members emphasized balancing cost protection with the risk of encouraging under-forecasting and agreed the framework should be coordinated with broader load-connection and CPP/ITP policies. CARE may establish the policy direction, with working groups developing the detailed design.

c. Incremental Large Load Cost

Sarah Bockelmann (SPP) presented a framework for determining whether new large loads should pay an incremental charge for ITP transmission investment. The assessment would compare the residual costs imposed on existing customers with the broader benefits of the investment before determining whether a charge is warranted. Members emphasized predictability, protection against non-materialized load, and clear applicability, including treatment of the 50 MW HILL threshold, spot loads, phased expansions, and existing agreements. Staff will develop a representative case study and refine policy options for CARE consideration in September.

The CARE Team discussed whether the large-load policy should apply to 765 kV facilities approved in the 2024 and 2025 ITPs. Members noted that prior survey results opposed retroactive application, while some supported revisiting existing service agreements if it could help achieve cost-allocation consensus. Staff noted that reopening the agreements would be complex and could raise contractual concerns.

Agenda Item 8 – Lookback Mechanism

This agenda item was skipped due to time constraints.

Agenda Item 9 – FERC Show Cause Compliance

Paul Suskie (SPP) provided a brief update on compliance efforts related to the FERC Show Cause Order. Mr. Suskie noted that, following direction received during the meeting, SPP staff will begin developing a Revision Request addressing a safe harbor limit for Attachment AQ and Attachment AX upgrades. Regarding transparency, Mr. Suskie highlighted RR808, which has been posted for stakeholder comment. RR808 would require SPP to make information received from transmission owners through the Attachment AQ and Attachment AX study processes publicly available. Staff is also considering an additional tariff requirement, consistent with FERC's direction, to ensure information regarding specific network upgrades is available to the public in a searchable format. Mr. Suskie encouraged stakeholders to provide feedback on RR808 as it progresses through the stakeholder process.

Agenda Item 10 – Survey

Cost Neutrality: The CARE Team discussed the cost neutrality principle and clarified that it is intended to protect existing customers from being unduly responsible for incremental costs associated with new large loads, while recognizing that existing customers may experience increased costs but also receive system benefits. The survey was revised to allow separate responses on cost neutrality for large load interconnection costs under Attachments AQ, AX, and

BA and for a share of the regional transmission portfolio associated with large load growth. Members noted that the two concepts could result in separate charges.

1. Large Load Cost Neutrality - New large loads, through their transmission customer, should be responsible for incremental costs associated with service including the costs of facilities to interconnect those customers so that existing customers are held cost-neutral as a consequence of serving the new load.
2. Large Load Cost Neutrality - New large loads, through their transmission customer, should be responsible for a share of regional transmission portfolios so that existing customers are held cost-neutral as a consequence of serving the new load.

	Both	Incremental Costs	Share of Regional Transmission Portfolio
Total Responses - 17	65% 11 votes	18% 3 votes	18% 3 votes

In response to questions regarding the definition of cost neutrality, Stuart Solomon (SPP Board) agreed to bring back additional language to further define the term.

Stranded Cost: Members discussed protecting existing customers from costs when large loads do not materialize, reduce demand, or cease operations, while allowing potential credits or transferability if replacement load develops. Because key implementation details remain unresolved, the survey will gauge support for the general policy concept rather than a final mechanism.

3. Large Load Stranded Cost Protection – Do you support the principal that new large loads through their transmission customer should be responsible for paying costs related to the planned new large load even if those large loads do not materialize, reduce demand or cease operations.

	Yes	No
Total Responses - 17	88.2% 15 votes	11.8% 2 votes

Large Load Definition: The CARE Team discussed a survey question regarding the definition of large loads and whether the definition should specifically address computational loads, such as data centers, separately from the existing HILL definition based on a 50 MW threshold. The survey allowed participants to select both options, providing additional input to inform recommendations.

4. For purposes of applying the Cost Allocation Large Load (CALL) framework which definition of "Large Load" should be used:

    A. The existing HILL definition (new or incremental load >50 MW or >10 MW for 69kv)

    B. A definition specific to computational loads

	HILL Definition	HILL & Computational Load
Total Responses - 17	100% 17 votes	29.4% 5 votes

Agenda Item 11 – Action Item Review

1. 2026 ITP Portfolio: Staff will develop a 20-year comparison of APC to the Load Ratio Share.
2. Staff will circulate the recent HITT – C1 FERC Order and HITT-C2 district court decision to the CARE Team.
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Agenda Item 12 – Next Steps

The CARE Team will meet in person in September in Kansas City, MO to refine its recommendations. The October CARE Team meeting will also be held in person and will include a vote on the final CARE report. Specific meeting location details will be shared once finalized.

Agenda Item 13 – Adjournment

Chair Hahn adjourned the meeting at 4:17 pm CT.

Month	Meeting Date	Location
September	Wednesday, Sept 16 (8:00-5:00 CT) Thursday, Sept 17 (8:00-5:00 CT)	Kansas City
October	Monday, Oct 19 (8:00-5:00 CT)	Denver
November	Sunday, Nov 15 (1:00-5:00 CT)	Little Rock
December	Tuesday, Dec 8 (8:00-12:00 CT)	Virtual