Balancing Authority of Northern California

Regular Meeting of the Commissioners of BANC

2:00 P.M.
Wednesday, November 20, 2024
2377 Gold Meadow Way
1st Floor Conference Room
Gold River, CA 95670

Balancing Authority of Northern California

NOTICE OF REGULAR MEETING AND AGENDA

Notice is hereby given that a regular meeting of the Commissioners of the Balancing Authority of Northern California (BANC) will be held on **November 20, 2024** at **2:00 p.m.** at **2377 Gold Meadow Way, 1st Floor Conference Room, Gold River, CA 95670.**

The following information is being provided as the forum by which members of the public may observe the meeting and offer public comment:

Phone: 1-301-715-8592 or 1-305-224-1968 **Meeting ID:** 824 5381 4220 **Passcode:** 371663

Meeting Link: https://us06web.zoom.us/j/82453814220?pwd=bVdnvzik0apdMwHSbPm2PqbbULDa30.1

Additional Public Meeting Location(s):

In addition to the primary meeting location listed above, any member of the public may also observe the meeting and offer public comment at the following address(es):

City of Shasta Lake
3570 Iron Court
Shasta Lake, CA 96019

AGENDA

1 **Call to Order and Verification of Quorum.**

2 **Matters subsequent to posting the Agenda**.

3 **Public Comment** – any member of the public may address the Commissioners concerning any matter on the agenda.

4 **Consent Agenda.**

A. Minutes of the Regular Commission Meeting held on October 23, 2024.

B. BANC Operator Report (October).

C. Compliance Officer Report (November).

D. PC Committee Chair Report (November).

E. General Manager's Report and Strategic Initiatives Update.

5 **Regular Agenda Items – Discussion and Possible Action.**

A. General Manager Updates.

i. Market Updates – EIM, EDAM, Markets+, WRAP.

ii. Key Initiatives Update.

B. Consider and Possibly Approve Resolution 24-11-01 *Acknowledgement and Acceptance of BANC Planning Coordinator Area 2024 Transmission Planning Assessment.*

C. Consider and Possibly Approve Resolution 24-11-02 *Resolution Setting the Regular Meeting Dates for 2025.*

D. Consider and Possibly Approve Resolution 24-11-03 *Approval of BANC Internal Compliance Program Charter – 2024 Updates.*

E. Member Updates.

6 **Adjournment**.

Accessible Public Meetings - Upon request, BANC will provide written agenda materials in appropriate alternative formats, or disability-related modification or accommodation, including auxiliary aids or services, to enable individuals with disabilities to participate in public meetings. Please send a written request, including your name, mailing address, phone number and brief description of the requested materials and preferred alternative format or auxiliary aid or service at least 3 days before the meeting. Requests should be sent to: Kris Kirkegaard, 555 Capitol Mall, Suite 570, Sacramento, CA 95814 or to administrator@braunlegal.com.

Balancing Authority of Northern California

Consent Agenda Items

A. **Minutes of the October 23, 2024 BANC Regular Meeting.**
B. **BANC Operator Report (October).**
C. **Compliance Officer Report (November).**
D. **PC Committee Chair Report (November).**
E. **General Manager's Report and Strategic Initiatives Update.**

MINUTES OF THE REGULAR MEETING
OF THE COMMISSIONERS OF
THE BALANCING AUTHORITY OF NORTHERN CALIFORNIA (BANC)

October 23, 2024

On this date, a Regular Meeting of the Commissioners of the Balancing Authority of Northern California was held at 555 Capitol Mall, Suite 570, Sacramento, CA 95814.

Representatives:

Member Agency	Commissioner
Modesto Irrigation District (MID)	Martin Caballero, Acting Chair
City of Redding	Nick Zettel
City of Roseville	Shawn Matchim, Alternate
Sacramento Municipal Utility District (SMUD)	Paul Lau
City of Shasta Lake	James Takehara
Trinity Public Utilities District (TPUD)	Absent

Other Participants:

Jim Shetler	General Manager
Tony Braun	General Counsel
Kris Kirkegaard	General Counsel Support
Laura Lewis	SMUD, Alternate
Michelle Williams	Western Area Power Administration
Bryan Griess	Western Area Power Administration

1. Call to Order and Verification of Quorum: Mr. Shetler & Mr. Braun confirmed that there was a quorum to proceed; attendance is noted above. Alternate Chair Caballero called the meeting to order at 2:04 p.m.

2. Matters Subsequent to Posting the Agenda: None.

3. Public Comment (any matter on the agenda): None.

4. Consent Agenda: Acting Chair Caballero invited comments from the Commission and a motion on the Consent Agenda; no comments.

ACTION: M/S (Lau/Matchim) to **approve the Consent Agenda**. Motion carried by a unanimous vote. (Absent: Commissioner Hauser).

5. Regular Agenda Items.

   A. General Manager Updates:

      i. Market Updates – EIM, EDAM, Markets+, WRAP.

      Mr. Shetler overviewed the following topics: ongoing operations, CAISO Benefits

Analysis; EIM Committee oversight (noting the suspension of the BANC Flex Ramp Product), Joint EDAM/DAME Tariff, EDAM Implementation (noting the FERC filing of the inter-SC trading amendment on 10/15/24), and the BANC RA Program (noting that a consultant has been engaged for an RA session with member staff.) Michelle Williams shared an update on the WAPA-SNR decision on EDAM participation.

Mr. Shetler also provided an update on the West-wide Governance Pathways Initiative, SPP Markets+, and WRAP. Commissioner questions were addressed by Mr. Shetler and Ms. Williams.

ii. BANC Resource Development Update.

Mr. Shetler shared that a meeting with Calpine and the Resource Committee had taken place. At this time, he forecasts initiating discussions with Calpine in Q4/Q1 2025.

B. Consider and Possibly Approve Resolution 24-10-01 *Approval of 2025 Annual Budget for BANC*.

Mr. Shetler reviewed the proposed 2025 BANC Budget and answered questions.

ACTION: M/S (Lau/Matchim) to **approve Resolution 24-10-01 *Approval of 2025 Annual Budget for BANC***. Motion carried by a unanimous vote. (Absent: Commissioner Hauser).

C. Draft 2024/2025 BANC Strategic Initiatives.

Mr. Shetler overviewed the draft initiatives. There were no questions from the Commission.

D. Consider and Possibly Approve Resolution 24-10-02 *Approval of Amended Management Services Agreement between BANC and Adirondack Power Consulting, LLC*.

Alternate Chair Caballero overviewed the proposed revisions to this agreement, and Mr. Braun also weighed in with comments. There were no questions from the Commission, but Commissioners Zettel and Caballero thanked Mr. Shetler for his service to BANC.

ACTION: M/S (Zettel/Lau) to **approve Resolution 24-10-02 *Approval of Amended Management Services Agreement between BANC and Adirondack Power Consulting, LLC***. Motion carried by a unanimous vote. (Absent: Commissioner Hauser).

E. Member updates.

Mr. Shetler noted that he anticipated a November meeting, but as of now, there are no planned items for December. Alternate Commissioner Matchim mentioned that Roseville will take title of two peaking generators at Roseville Energy Park from the state as of November 1.

6. Closed Session: The Commission retired to closed session at 2:55 p.m. for conference with legal counsel in anticipation of litigation pursuant to Cal. Gov't Code § 54956.9; anticipated litigation, one case: (1) matters related to Federal Energy Regulatory Commission Docket No. ER23-2686-000.

The Commission adjourned from Closed Session at 3:44 p.m., where no formal action was taken.

Minutes approved on November 20, 2024.

____

C. Anthony Braun, Secretary

BALANCING AUTHORITY OF NORTHERN CALIFORNIA

P.O. BOX 15830 • D109 • SACRAMENTO • CA 95852 -1830

TO: BANC Commission

RE: BANC Operator Report for October 2024

Operations:

- BA Operations: Normal
- Significant BA Issues: None
- Declared BA Energy Emergency Alert Level (EEA): N/A
- RSG Activations
  - 0 Qualifying Event
  - 0 MW Qualifying Event request
  - 0 MW average generation lost
  - 0 MW maximum generation lost
  - Generating unit(s) and date(s) affected: None
  - All recoveries within 0 minutes
- USF
  - 18 of 31 days with instances of USF mitigation procedure utilized
    0 days on Path 66
  - No operational impact on BANC
- BAAL Operation:
  - Maximum duration of BAAL exceedance: 8 Minutes
    COI derate and associated import curtailment due to the Pine Fire in Oregon
  - Number of BAAL exceedance >10 minutes: none
  - BAAL violation (BAAL exceedance >30 minutes): None
- Frequency Response (FR) Performance – Quarterly Metric:
  - 2024 Frequency Response Obligation (FRO): -15.8 MW/0.1Hz

Monthly Notes:

- None

Compliance Officer Report
BANC Commission Meeting
November 2024

The following summarizes routine issues for the Commission's information and consideration. Any major issues or action items will be identified on the Commission agenda for action.

BA Compliance Issues:

- No significant operational Balancing Authority compliance events occurred.
- All required BA compliance reports and operating data were submitted to WECC.
- BANC's 2025 Entity Monitoring Schedule (WECC):
  - BANC/SMUD is one of two entities that have been in discussions with WECC to explore reducing the audit scope by using the 'work of others,' such as the work performed during the mock audit. An initial audit scope discussion with WECC was held, and another is planned. The scope will not be finalized until the Audit Notice Package.
  - The Audit Notice Package is expected to be received on January 10, 2025.
  - The WECC Compliance Audit is currently scheduled to take place May 12 - 23, 2025 (off-site and on-site weeks.)

BANC MCRC:

The next BANC MCRC meeting is scheduled to be held at 10:00 AM on Monday, December 9th via teleconference.

PC Committee Chair Report
BANC Commission Meeting
November 2024

The following summarizes Planning Coordinator-related activities and updates for the Commission's information and consideration. Any major issues or action items will be identified separately on the Commission agenda for action.

BANC PC Committee Updates and/or activities:

SMUD staff continues to work toward demonstrating compliance with PC-related NERC reliability standards.

- FAC-014-3 - Establish and Communicate SOLs - Staff revised the BANC PC documented process required by R6 of FAC-014-3 as recommended by Archer during the mock audit. In addition, based on the mock auditor recommendations, a FAC_014-3 report was created to comply with FAC-014-3. Both the newly created report and revised documented process were shared with BANC PC Participants for review and comment by November 8th.

- MOD-033-2 Model Validation – The Steady State data request has been completed and base case creation is underway.

- PRC-010-2 - Undervoltage Load Shedding – BANC received data and updated UVLS models from Roseville. Staff completed performing the UVLS assessment studies. A draft version of the report was sent to Roseville for review and comment on September 19th with a due date of November 1st, along with an updated version of Roseville's UVLS scheme. The due date for the report is December 20th.

- PRC-026-2 - Relay Performance During Stable Power Swings - Staff incorporated comments received on the draft report and shared the finalized 2024 BANC PC PRC-026-2 report with PC Participants on October 11th.

- TPL-001-5.1 Transmission System Planning Performance –The 2024 BANC PC Transmission Planning Annual Assessment Report was approved by BANC PC committee members on October 4th, and it is currently awaiting BANC Commission approval (on November meeting agenda.)

- TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events - Staff is currently performing GMD study on the GIC current impact on the bulk system voltages (230 kV) and reactive power consumptions, which the 2022 GMD study done by WECC did not include. The study is expected to be completed by the end of this year.

The table below shows the current status of all PC-related NERC standards:

	PC Standard	Estimated % Complete	Notes
1	FAC-002-4 Interconnection Studies	100%	There are no BES interconnection projects in 2024 for BANC PC Participants per 2024 survey as no system upgrades meet the new definition of qualified changes for BANC PC for this year.
2	FAC-010-3 SOL Methodology for Planning Horizon	N/A	This standard is inactive as of 03/30/2024.
3	FAC-014-3 Establish and Communicate SOLs	90%	Staff revised the BANC PC documented process required by R6 of FAC-014-3 as recommended by Archer during the mock audit process and created an accompanying report to comply with FAC-014-3. These items were shared with BANC PC Participants for review and comment by 11/08/2024.
4	IRO-017-1 Outage Coordination	0%	Awaiting acceptance of the 2024 annual assessment to send to the Reliability Coordinator.
5	MOD-031-3 Demand and Energy Data	100%	Staff completed the 2024 Loads and Data request cycle. WECC broke up the data request into multiple spreadsheets with two sets of due dates and a narrative request with a separate due date. The sheets have been completed with WECC-requested load and energy data and sent to WECC by the due dates. WECC sent out a narrative request, and that request was sent to BANC PC Participants for input. Responses were aggregated and uploaded to WECC on 03/19/2024.
6	MOD-032-1 Data for Power System Modeling & Analysis	100%	Ongoing activity. Data requests to fulfill 13-month cycle for compliance were sent 02/09/2024.
7	MOD-033-2 System Model Validation	20%	Base case creation is underway.
8	PRC-006-5 Underfrequency Load Shedding	100%	Staff sent the WECC-requested annual UFLS data request from BANC PC Participants to the Off-Nominal Frequency System Protection (OFSPR) Southern Island Load Tripping Plan (SILTP) technical writer on 05/29/2024. The SILTP technical writer finalized all the shared data and sent the completed report to WECC on 07/01/2024. Staff continues to participate in WECC Under-Frequency Load Shed Working Group representing the BANC PC as needed.

	PC Standard	Estimated % Complete	Notes
9	PRC-010-2 Undervoltage Load Shedding	90%	BANC received data and updated UVLS models from Roseville. Staff completed performing the UVLS assessment studies. A draft version of the report was sent to Roseville for review and comment on 09/19/2024 and comments are due by 11/01/2024.
10	PRC-012-2 Remedial Action Schemes	10%	New standard effective on 01/01/2021. Study Plan finalized 04/10/2020. The R4 assessment is not required until 01/01/2026, which means that the assessment and report must be finalized and published by 01/01/2025.
11	PRC-023-6 Transmission Relay Loadability	100%	Staff incorporated comments received on the draft report and shared the finalized 2024 BANC PC PRC-026-2 with PC Participants on 10/11/2024.
12	PRC-026-2 Relay Performance During Stable Power Swings	100%	Staff incorporated comments received for the draft report and shared the finalized 2024 BANC PC PRC-026-2 report with PC Participants on 10/11/2024.
13	TPL-001-5 Transmission System Planning Performance	99%	Report is finished and awaiting BANC Commission Approval.
14	TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events	15%	Staff is performing GMD study on the GIC current impact on the bulk system voltages (230 kV) and reactive power consumptions. The study is expected to be completed by the end of this year.

GM Report
BANC Commission Meeting
November 20, 2024

I wanted to summarize routine issues for the Commission's information and consideration. Any major issues or action items will be identified separately on the Commission agenda for action.

Outreach Efforts:

Refer to GM outreach report provided under separate distribution. In addition, here are some other noteworthy items:

LADWP/Seattle City Light/SRP

Dialogue continues with these entities regarding EIM participation and day-ahead market issues. We continue to interact on an informal basis to make sure we are aligned on issues from a POU perspective. We are holding periodic calls to provide updates and discuss issues. We have also used this forum to discuss POU positions regarding the EDAM development, other market design issues (e.g.- SPP Markets+), and to discuss potential summer heat wave impacts on EIM and EDAM design.

Market Initiatives:

EIM Participation

Staff continues monitoring EIM participation. CAISO quarterly benefit reports show that BANC is seeing benefits from EIM participation, with the 3rd Quarter 2024 report showing gross benefits of $48.78 million for BANC, with a total of $734.58 millions of gross benefits for BANC since joining in 2019.

With respect to BANC EIM Phase 2 effort, BANC has been passing the EIM Balancing, Capacity, and Flex Ramp tests with a high success rate. Both the Technical Evaluation Subcommittee and the Settlements Subcommittee are meeting routinely and evaluating EIM operations, with reports out to the EIM Committee.

EDAM Participation

FERC approved the EDAM/DAME tariff on 12/21/23 with the exception of the Access Charge. In its order, FERC accepted the overwhelming majority of the proposed market rules and rejected without prejudice one element of the EDAM proposal related to transmission revenue recovery (TRR) for market participants. The CAISO filed a revised proposal on TRR with FERC on April 12, 2024, which was approved by FERC on June 12, 2024. This resolves the concerns by the potential EDAM participants and should allow several to move forward. In October, CAISO filed another tariff amendment that would allow the use of inter-SC trades by EIM and EDAM entities. The CAISO requested approval by the end of 2024. This will resolve an issue for WAPA-SNR.

A group of Western state regulators (AZ, CA, NM, OR, and WA) sent a letter to CREPC/WIRAB in July 2023 supporting the creation of an independent entity that would leverage the existing CAISO infrastructure for EIM and eventually EDAM to develop a cost-effective West-wide market. This would include a range of voluntary market services from EIM to EDAM to an RTO. It also deals with the CAISO governance issue by creating a separate independent entity. BANC views this as a positive development in ensuring a West-wide market that will include CA and supports the effort. The Western Markets Governance Pathways Initiative has formed a "Launch Committee" made up of stakeholders from twelve sectors to organize this effort. One of the sectors is for POUs. The BANC General Manager is serving as a representative for the POU Sector. The Launch Committee issued a draft proposal on April 10, 2024, outlining a stepwise approach to independent oversight over CAISO markets. BANC joined in with a group of 32 other entities in support of the Launch Committees Step 1 proposal to move to primary authority for the WEM Governing Body over market rules and supporting the Launch Committee further fleshing out the draft Step 2 proposal to move to the formation of a Regional Organization with an independent board that would have sole authority over market rules within the current CAISO tariff structure. The Launch Committee approved the Step 1 proposal on 5/31/24 and sent this to the CAISO for consideration and possible implementation through its stakeholder process. The CAISO Board of Governors and the WEM Governing Body approved the Step 1 proposal on 8/13/24. On 11/8/24 the combined boards approved the necessary documentation to allow the Step 1 primary authority model to move forward once the level of EDAM Implementation Agreement signatories reaches the designated threshold value and FERC approvals are received. The Launch Committee issued a final draft of the Pathways Step 2 proposal on November 15 and has scheduled a public meeting on November 22 to approve the proposal.

Based upon the Commission's unanimous approval at its 8/23/23 meeting, BANC staff have initiated the project efforts for EDAM Implementation, which includes dialogue with the CAISO project management group for EDAM and establishing the internal BANC project team. Initial kick-off of the BANC EDAM project team was held on 12/13/23. BANC met with Pacificorp on January 11, 2024, and February 26, 2024, to start discussing joint EDAM implementation issues and has initiated project discussions with the CAISO. We had follow-up meetings in early June with Pacificorp and other interested EDAM parties regarding lessons-learned on EDAM project efforts and to review a draft of the Pacificorp OATT. We have also held discussions with Portland General Electric regarding their implementation efforts and with LADWP. As noted at the Strategic Planning Session in August, BANC is adjusting its implementation plan consistent with the WAPA-SNR decision-making process and assumes moving from a Spring 2026 to Spring 2027 implementation. With WAPA's October approval to allow SNR to finalize negotiations on EDAM participation, staff is moving forward with approving the EDAM Implementation Agreement with the CAISO.

Other Market Developments

In parallel with the EDAM process, SPP has announced its "Markets+" effort to support utilities in the West with a range of market options from EIM to full RTO services. SPP filed its Markets+ tariff at FERC on March 29, 2024. SPP received a deficiency letter from FERC on 7/31/24 with a request to provide responses within 60 days. SPP responded to the deficiency letter in late September. SPP deferred seeking additional funding for the next phase of market development and commitments to Markets+ until later in 2024. It is our understanding that entities in the West that are supportive of Markets+ are in the process of seeking approvals to fund the next phase of the development. SPP has also indicated that "go-live" for Markets+ will be delayed until 2027. Staff views Markets+ as a fallback option for BANC and will continue to monitor this market option but does not plan on seeking funding for participation in this next phase of their efforts.

WAPA:

Market Engagement

WAPA-SNR continues to be an active participant in the EIM.

As noted above, the WAPA administrator issued her decision in late October to allow SNR to move forward with finalizing negotiations to participate in EDAM.

WECC

WECC Board Meetings

The last set of Board and committee meetings were held on September 17-18, 2024, in Salt Lake City, UT, which was the WECC Annual Meeting. The next set of meetings will be December 10-11, 2024, in Salt Lake City, UT.

Western Power Pool (WPP)

Western Resource Adequacy Program (WRAP)

As agreed previously, BANC has informed WPP that it will not be participating in the Western Resource Adequacy Program (WRAP) due to our lack of ability to have firm, long-term transfer capability at Mid-C, which is the hub for the WRAP interchanges. BANC continues to monitor development of the WRAP and hold periodic discussions with WPP regarding our ability to participate in the future. WPP announced in late April 2024 that their WRAP participants have formally requested a delay in the "binding". The WRAP participants recently formally voted to extend the binding date to 2027. WPP is in the process of finalizing changes to the WRAP implementation rules and are currently in the process of pre-tariff filing discussions with FERC. It is expected that the amended tariff will be filed soon after the New Year.

RSG and FRSG Participation
BANC continues to participate in the Reserve Sharing Group and the Frequency Response Sharing Group through the WPP and receive benefits in doing so.

WestTEC
WPP has initiated a new process called the Western Transmission Expansion Coalition (WestTEC) which is intended to provide coordination among the current regional transmission planning entities in the West (CAISO, Northern Tier, and WestConnect) to determine if there are some broader regional transmission projects that should be considered. WPP has obtained DOE funding for this effort which is in the early phases of implementation. They are currently envisioning a 2.5-year process with an initial 10-year plan out in the first year and a 20-year plan the second year.

CDWR Delta Pumping Load:
BANC is coordinating with SMUD, CDWR, WAPA, and the CAISO regarding how the construction and pumping loads and ancillary services will be provided for this project. The CAISO has reached out to BANC/SMUD/WAPA-SNR regarding contacts for initiating discussions on how CAISO will supply energy for the construction loads in our footprints. SMUD reported that CDWR has approached them regarding the revised environmental review and updated project schedule and SMUD is initiating updated studies. The current schedule for the project is to initiate construction in 2033 with operations initiated in 2040's.

SB100 Implementation
As part of SB100, the CPUC, CEC, and CARB (Joint Agencies) are required to collaborate with the California BAs to develop a quadrennial report on the status of achieving the goals of SB100. The four POU BAs (BANC, IID, LADWP, and TID) are collaborating on positions and responses, facilitated by CMUA. The final, initial report was issued on 3/15/21. The CEC did reach out to the POU BAAs in early March 2021 seeking more engagement with the BAAs for the next round of analysis for the SB100 effort. Based upon recent discussions, the POU BAAs have hired a consultant via CMUA to assist in this effort. The Joint Agencies are working to finalize the SB100 effort to support issuing an update report by the required date of 1/1/25. BANC is working with IID, LADWP, and TID to coordinate our engagement in this effort.

Western Electricity Industry Leaders (WEIL) Group

The WEIL CEOs last met on October 11, 2024, in Portland, OR. The next meeting of the WEIL group is planned for February 21, 2025, in San Diego, CA.

Strategic Initiatives

The 2023/2024 Strategic Initiatives are attached to this report.

BANC 2024/2025 Strategic Plan - Routine Initiatives - November 2024 Update

No./Priority	Focus Area	Initiative	Responsibility	Target Due Date	Status
1 Medium	INDEPENDENCE	Effectively oversee the BA operations.	Jim Shetler	Ongoing	See monthly Ops, PC, Compliance, & GM Reports
2 Medium		Maintain long-term succession plan and traits for General Manager	Jim Shetler/Commission	Ongoing as Necessary	No update planned for 2025
3 Medium		Develop appropriate policies, procedures, & action tracking	Jim Shetler/BB&W	4th Qtr. 2025	
4 Medium	OUTREACH	Engage in industry forums (WECC, RC West, NWPPA, etc.)	Jim Shetler	Ongoing	Attend RC West, WECC Board, WEIL, & WPP mtgs.
5 Medium		Coordinate with other POU BAs (Ca and regionally)	Jim Shetler	Ongoing	Coordinating with SCL/SRP/ LA/TP/TID on EIM/EDAM & SB100
6 Medium		Outreach to regulatory and legislative bodies on key issues	Jim Shetler/BB&W	Ongoing as Necessary	EDAM/Pathways discussion w/ FERC 10/29
7 Medium		More formal engagement with TID on BA/EIM/EDAM issues	Jim Shetler/BB&W	Ongoing	Continue periodic discussions on areas of collaboration
8 Medium	ASSETS	Monitor RA development in WI	Jim S./BB&W/Res. Com.	4th Qtr. 2025	
9 Medium		Develop BANC-wide IRP Report	Jim S./Res. Comm	3rd Qtr. 2025	Discussing options w/SMUD
10 High		Upgrade BANC RA Program	Jim S./Res. Comm.	4th Qtr. 2025	BANC RA symposium 12/2
11 Low	MEMBER SERVICES	Identify and outreach to potential new BANC members	Jim Shetler	Ongoing as Appropriate	

BANC 2024/2025 Strategic Plan - Focused Initiatives - November 2024 Update

No./Priority	Focus Area	Initiative	Responsibility	Target Due Date	Status
12 High	INDEPENDENCE	Manage EIM Phase 2 Going Forward	Jim Shetler/SMUD	Ongoing	Manage Phase 2 operations including EIM, Tech Anal. & Settlements committees
13 High		EDAM implementation effort ~ Manage BANC EDAM implementation	Jim Shetler/BB&W/ Utilicast	Apr-27	Reviewing EDAM IA for signature
14 Medium	OUTREACH	Evaluate opportunities to engage other entities in market development	Jim Shetler	Ongoing	Coordinating with SCL, SRP, LADWP, TID, Tacoma, Idaho, PAC, & PGE
15 Medium		Regional Policy Issues: Monitor/ weigh-in where appropriate	Jim Shetler/Commission	Ongoing	
16 High		Market Regionalization: ~Monitor ongoing discussions at WEIL, WWGPI, & etc.	Jim Shetler/BB&W/WEL	Ongoing	Final Pathways proposal 11/15
17 High		Coordinate with CA BAs on SB100 effort	Jim Shetler/BB&W	Ongoing	
18 High	ASSETS	~ Develop agreements for Sutter CS Project	Jim S./BB&W/Res. Com.	4th Qtr. 2025	Initiating agreement development
19 High		~ Develop/issue BANC resource solicitation	Jim S./BB&W/Res. Com.	2nd Qtr. 2025	
20 Medium	MEMBER SERVICES	Evaluate possible support to participants for EIM operations	Jim S.	Ongoing	

Balancing Authority of Northern California

Agenda Item 5A

1. **BANC PC Area 2024 Transmission Planning Assessment.**
2. **Resolution 24-11-01 *Acknowledgment and Acceptance of BANC PC Area 2024 Transmission Planning Assessment*.**

Braun Blaising & Wynne, P.C.

Attorneys at Law

11/14/24

TO: BANC Commission

FROM: BANC Counsel

RE: **Acknowledgement and Acceptance of BANC PC Area 2024 Transmission Planning Assessment**

Included in the Commission packet for the November 20, 2024 BANC Commission meeting is the BANC Planning Coordinator (PC) Area 2024 Transmission Planning Assessment.[1] This document was produced by the Sacramento Municipal Utility District (SMUD), which serves as the BANC PC Services Provider. Concurrence from each member of the BANC Planning Committee was received on or before October 4, 2024. The performance of the BANC PC Area's portion of the Bulk Electric System (BES) was assessed in order to demonstrate that all of the performance requirements specified in the North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001-5 (Transmission System Planning Performance) were met for years 2025 through 2034 (planning years one through ten).

A number of studies were performed to assess BES performance under various scenarios. The Assessment did not identify any new system deficiencies or criteria violations for the MID and Roseville Electric portions of the BES. For the REU and SMUD systems, P6 contingencies that cause thermal overloads were identified, but these can be mitigated with allowable system adjustments in between outages. No new corrective action plans were developed for this assessment. The attached report provides additional information. This assessment demonstrates BANC's compliance with the NERC TPL-001-5 Reliability Standard, the WECC TPL-001-WECC-CRT-3.2 Transmission System Performance Criterion, and the BANC PC Participants' respective voltage criteria.

Compliance with NERC Reliability Standard TPL-001-5 is one of several that must be met by the BANC PC, and the Commission is requested to acknowledge receipt and accept the BANC PC Area 2024 Transmission Planning Assessment by resolution.[2]

[1] Entities included in the BANC PC Area include: the Modesto Irrigation District (MID), Redding Electric Utility (REU), Roseville Electric and SMUD. The City of Shasta Lake and the Trinity Public Utilities District are part of the Western Area Power Administration – Sierra Nevada Region PC Area.

[2] Refer to BANC PC Committee Chair's Report for November 2024 for more information regarding the status of all PC-related NERC reliability standards.

555 Capitol Mall, Suite 570, Sacramento, California 95814
Telephone: (916) 326-5812 ◆ www.braunlegal.com

Balancing Authority of Northern California

BANC PC Area
2024 TPL-001-5.1 Assessment

September 30th, 2024

Final

Executive Summary

An assessment was performed to demonstrate that the Balancing Authority of Northern California (BANC) Planning Coordinator (PC) portion of the Bulk Electric System (BES) meets the performance requirements specified in the TPL-001-5.1 NERC Reliability Standard for the near term and long term planning horizons.

Analyses were performed for steady state and stability to assess the BES performance following various NERC Category P0-P7 contingencies and extreme events as well as sensitivity studies. A spare equipment unavailability analysis was conducted with NERC Categories P0, P1 and P2 contingencies. The short circuit analysis of interrupting capability was supported by current and qualified past studies from each BANC PC Participant, whereas the steady state and stability analyses were supported by current studies.

For all analyses performed, there were no new system deficiencies or criteria violations identified for the MID and RE portions of the BES. The SMUD and RDNG systems have P6 contingencies that cause thermal overloads, but these can be mitigated with allowable system adjustments in between outages. No new corrective action plans were developed for this assessment.

The assessment demonstrates BANC PC's compliance with the NERC TPL-001-5.1 Reliability Standard, the WECC TPL-001-WECC-CRT-4 Transmission System Performance Criterion, and the BANC PC participant's respective voltage criteria.

Appendix A documents the TPL-001-5.1 requirements and the associated sections in this assessment that demonstrate compliance.

Table of Contents

Terms

BA	Balancing Authority
BANC	Balancing Authority of Northern California
MID	Modesto Irrigation District
NERC	North American Electric Reliability Corporation
PC	Planning Coordinator
PC Participants	SMUD, MID, RE, and RDNG
RE	Roseville Electric
RDNG	Redding Electric Utility
SMUD	Sacramento Municipal Utility District
TP	Transmission Planner
WECC	Western Electricity Coordinating Council

1 Introduction

The Balancing Authority of Northern California (BANC) is a Joint Powers Authority (JPA) consisting of the Sacramento Municipal Utility District (SMUD), Modesto Irrigation District (MID), Roseville Electric (RE), Redding Electric Utility (RDNG), Trinity Public Utilities District, and the City of Shasta Lake Utilities. BANC assumed the Balancing Authority (BA) responsibilities on May 1, 2011, with SMUD providing the BA operator services on a contract basis.

On January 1, 2017, BANC registered as the NERC Planning Coordinator (PC) for four of its members with a goal of fully complying with all PC-related reliability standards by January 1, 2018. The four BANC members that are in the BANC PC area are SMUD, MID, RE, and RDNG (individually "PC Participant" and collectively "PC Participants"). The City of Shasta Lake and Trinity Public Utility District are BANC members but are not PC Participants[1]. BANC and SMUD entered into an agreement wherein SMUD provides PC services to BANC on a contractual basis.

An assessment was performed for the BANC PC[2] portion of the Bulk Electric System (BES) in 2024 to demonstrate that it meets all performance and other requirements specified in the TPL-001-5.1 NERC Reliability Standard [1] for the near and long term planning horizons.

This report documents the assessment and is structured as follows:

- Section 2 provides the scope of this assessment.
- Section 3 provides the assumptions used in this assessment.
- Section 4 provides the analyses performed for this assessment.
- Section 5 provides the results of this assessment.

Appendix A documents the TPL-001-5.1 requirements and the associated sections in this assessment that demonstrated compliance.

2 Study Scope

The BANC PC annual assessment measured the BES performance at the BANC PC Participant area for the near and long term planning horizons with the specific goal of demonstrating compliance with the TPL-001-5.1 NERC Reliability Standard. As such, the assessment was comprised of the following analyses:

- Steady state analysis
- Stability analysis

[1] The Western Area Power Administration – Sierra Nevada Region (WAPA-SNR) is also inside the BANC BA, but it is not a member of the BANC JPA. However, WAPA-SNR is an active participant in BANC activities. Additionally, WAPA-SNR is a registered PC and will serve as the PC for the Trinity Public Utilities District and the City of Shasta Lake. Thus, all BANC members are covered under either the BANC or WAPA-SNR PC registrations.
[2] BANC PC annual assessment includes performing an assessment for SMUD's non-BES 115 kV elements and WAPA's – SNR portion of the BES to insure reliable operation across the BANC PC area. The results of these studies are available to BANC members and upon request to entities with an NDA.

- Sensitivity analysis
- Spare equipment unavailability analysis
- Short circuit analysis
- Known outage analysis

2.1 Steady State Analysis

A steady state analysis shall assess the system performance at peak load in the near-term and long-term transmission planning horizons. The steady-state performance shall be assessed in the near-term horizon using peak load cases that model year two (2026) and year five (2029). The long-term horizon shall be assessed using a peak load case for year ten (2034) as it represents the furthest out year of the long-term planning horizon, helping to identify potential future issues that may require significant lead time to adequately address and resolve.

In addition, the system performance at off-peak shall be assessed for one of the five years. Year two (2026) was selected for the off-peak load study scenario.

2.2 Stability Analysis

A stability analysis shall be performed to assess the system performance in the near-term planning and long-term planning horizon. The peak and off-peak cases for year two (2026) and peak case for year 5 (2029) shall be used in the assessment for the near-term analysis and the peak case for year ten (2034) shall be used for the long-term analysis.

2.3 Sensitivity Study Scenarios

Sensitivity cases shall be used to assess the impact of changes to the basic assumptions used in the model. The sensitivity analysis shall vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in System response:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified transmission facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable loads and demand side management.
- Duration or timing of known transmission outages.

A 1-in-10 year load forecast for the BANC PC area increased by 5% shall be used as the sensitivity study scenario to assess the near-term transmission planning horizon portion of the steady state analysis for the summer peak years 2025 for MID, RE, RDNG, and SMUD. For the year 5, this will only be done for MID, RE, and RDNG. In accordance with SMUD's Zero Carbon Plan (ZCP), SMUD will be studying an altered generation dispatch for the year 5 (2029) summer peak sensitivity scenario. A description of the altered dispatch can be found in section 4.1.4. For the off-peak sensitivity case for year 2026 a reduced generation dispatch with the largest generation plant in each BANC PC participants' area turned off (to stress imports) was chosen.

2.4 Spare Equipment Unavailability Study Scenarios

An entity's spare equipment strategy could result in the unavailability of major transmission equipment that has a lead time of one year or more. The impact of possible equipment unavailability on system performance was studied for P0, P1, and P2 categories. BANC PC performed the spare equipment unavailability analysis based on the BANC PC participants' spare equipment strategies for major transmission equipment that has a potential lead time of one year or more. The spare equipment strategy from RDNG showed that RDNG's Airport 230/115 kV transformer and 115/13.8 kV GSU transformer could be out of service for one year or more. Studies were performed with these facilities out of service to assess the impact on system performance for the possible unavailability.

The spare equipment strategies from SMUD, MID and RE found no major transmission equipment with a lead time of one year or more.

2.5 Short Circuit Analysis

A short circuit analysis shall be used to assess the near-term transmission planning horizon using peak generation and determine whether circuit breakers have the interrupting capability for faults that they will be expected to interrupt. The short circuit analysis uses the system short circuit model with any planned generation and transmission facilities in service which could impact the study area. Each PC Participant is responsible for conducting their own short circuit study and providing the results of said study to be included in this assessment.

2.6 Known Outage Analysis

A known outage analysis will be performed in accordance with the "BANC PC Known Outage Analysis Procedure" to determine if any planned facility outages will cause criteria violations in the near term horizon. Each PC participant is responsible for informing BANC PC of any known outages that will take place during the assessment study years.

2.7 Summary of Study Years and Scenarios

Table 2.6 below summarizes the various types of analyses and study scenarios which were performed as part of the transmission system planning assessment, and the study years that were selected for each analysis.

Table 2.6 – Study scenarios and years performed in this assessment

		Near-term horizon year					Long-term horizon year				
Analysis	Scenario	1 '25	2 '26	3 '27	4 '28	5 '29	6 '30	7 '31	8 '32	9 '33	10 '34
Steady state	Peak	-	X	-	-	X	-	-	-	-	X
	Off-peak	-	X	-	-	-	-	-	-	-	-
Stability	Peak	-	X	-	-	X	-	-	-	-	X
	Off-peak	-	X	-	-	-	-	-	-	-	-

		Near-term horizon year					Long-term horizon year				
		1	2	3	4	5	6	7	8	9	10
Analysis	Scenario	'25	'26	'27	'28	'29	'30	'31	'32	'33	'34
Spare equipment unavailability	Peak	-	X	-	-	-	-	-	-	-	-
	Off-peak	-	-	-	-	-	-	-	-	-	-
Steady state sensitivity	Peak	-	X	-	-	X	-	-	-	-	-
	Off-peak	-	X	-	-	-	-	-	-	-	-
Stability sensitivity	Peak	-	X	-	-	-	-	-	-	-	-
	Off-peak	-	X	-	-	-	-	-	-	-	-
Short circuit[3]	Peak	Years vary dependent upon each PC Participant.									

3 Study Assumptions

The study assumptions used in this assessment are detailed in the sections that follow.

3.1 System Model Representations

This assessment utilized system models maintained by the PC for the BES portion and non-BES portion of the BANC PC area. These system models were developed in accordance with NERC Reliability Standard MOD-032 and were submitted to the WECC for use in the compilation of base cases for various study years and scenarios.

All cases used are developed from WECC approved base cases for this assessment; these cases are listed in Table 3.1 below. Each study case was updated to reflect the most recent system operating conditions and topologies, including the load forecasts and generation dispatch levels, provided by each BANC PC Participant for the year and scenario studied.

Table 3.1 - WECC base cases that were used in the assessment

Study Year	Scenario	WECC Base Case	WECC DYD file	WECC Approval Date
2026	Summer Peak	24HS3b1	24HS31.dyd	9/11/2023
2026	Heavy Spring	24HSP1a1	24HSP11.dyd	4/28/2023
2029	Summer Peak	29HS2a1	29HS21.dyd	9/29/2023
2034	Summer Peak	34HS1a1	34HS11.dyd	10/25/2023

Assumptions and modifications for the cases are further described in the subsections below. These models use data consistent with that provided in accordance with all relevant modeling data reliability standards and are supplemented with data from other sources as necessary. Prior to the start of the TPL assessment, the WECC base cases to be used are sent to the PC Participants to

[3] The short circuit analysis performed for different years within the Near-Term Planning Horizon was dependent upon the data submitted by the BANC PC Participants.

review and the most accurate system data is provided as updates to these cases, if necessary. These are then utilized for the assessment.

3.1.1 Existing Facilities

The system models used in this assessment represented all existing facilities.

3.1.2 New Planned Facilities and Changes to Existing Facilities

The system models used in this assessment represented all new planned facilities and changes to existing facilities. See Appendix B for details of the new planned facilities and changes to existing facilities.

3.1.3 Real and Reactive Load Forecasts

The system models used in this assessment represented the most recent real power load forecasts and power factor from each BANC PC Participant. A 1-in-10 peak load forecast was used in the assessment for the summer peak study scenarios and typical off-peak loads were used for the spring off-peak scenario. BANC PC assumes a load level at 60% of the seasonal peak load to be considered off-peak.

SMUD has a demand side management program that incentivizes customers to reduce their energy usage during high load hours, thus reducing the overall demand on the system. The impact of SMUD's DSM program is included in SMUD's load forecast. MID has two DSM programs as well, but the purpose of MID's DSM programs is to ensure MID has the necessary resources to meet its 15% planning reserve *above* the 1-in-10 load forecast, and thus the program is not modeled *in* their load forecast. RE and RDNG do not have DSM programs in their system.

A 1-in-10 peak load forecast increased by an additional 5% was used for the sensitivity analysis. The off-peak sensitivity was performed using a reduced generation dispatch with the largest generation plant in each BANC PC participants' area turned off to stress imports. Table 3.1.4 below summarizes the load forecast data for all BANC PC Participants.

Table 3.1.4 – Load demand forecasts

		Real Power (MW)			
PC Participant	Scenario	2026	2029	2034	Power Factor
SMUD	1-in-10 Summer Peak	3,480	3,511	3,576	0.983 lag
	Spring Off-Peak	2,070			0.99 lag
MID	1-in-10 Summer Peak	755	780	820	0.987 lag
	Spring Off-Peak	662			
RDNG	1-in-10 Summer Peak	233.71	233.74	236.18	0.977 lag
	Spring Off-Peak	76.72			
RE	1-in-10 Summer Peak	396	421	446	0.985 lag
	Spring Off-Peak	230			

3.1.4 Firm Transmission Service and Interchange

Firm transmission service was not modeled in this assessment since BANC PC members have no commitments to provide firm transmission service.

Regarding interchange, SMUD currently has multiple contracts for interchange service from WAPA and PG&E. They are listed as follows:

- WASN has a contract with SMUD for 342 MW (bidirectional) to be delivered to SMUD at the Elverta/Hurley substations. Expires 1/15/2033.
- WASN has a contract with SMUD for 165 MW (unidirectional) to be delivered to SMUD at the Elverta/Natomas substations. Expires 7/1/2034.
- WASN has a contract with SMUD for 310 MW (unidirectional) to be delivered to SMUD at the Elverta/Hurley substations. Expires 12/31/2024.
- WASN has a contract with SMUD to deliver 318 MW of its CVP generation units' output to SMUD.
- PG&E and SMUD have a PPA for 48 MW (bidirectional) to be delivered to SMUD at the Rancho Seco substation.

These imports were modeled in the appropriate base cases.

3.1.5 Resources Required for Load

The system models used in this assessment represented the supply side resources and their projected dispatches for the peak and off-peak load conditions as summarized in Table 3.3.

Demand side resources were modeled in the SMUD system in the form of distributed generation that is netted out of the load. This assessment also represented demand side load response utilizing the WECC approved composite load model.

Table 3.1.6A –Supply-side resources and associated dispatch for the peak and off-peak scenarios (Hydro)

System	Plant	Unit	Maximum Operating Capacity (MW)	Dispatch Level (MW)			
				Summer Peak Year			Spring Off-Peak
				2026	2029	2034	2026
SMUD	Loon Lake	1	79	25	25	25	25
	Robb's Peak	1	25.5	20	20	20	20
	Jones Fork	1	10	10	10	10	10
	Union Valley	1	46	44	44	44	44
	Jaybird	1	76.5	56	56	56	56
		2	76.5	76	76	76	76
	Camino	1	79	56	56	56	56
		2	77	34	34	34	34
	White Rock	1	116	100	100	100	100
		2	133	116	116	116	116
	Total		**718.5**	**537**	**537**	**537**	**537**
MID	Don Pedro	3	55	45.0	45.0	45.0	45.0
	Total		**55**	**45.0**	**45.0**	**45.0**	**45.0**

Table 3.1.6B –Supply-side resources and associated dispatch for the peak and off-peak scenarios (Thermal)

System	Plant	Unit	Maximum Operating Capacity (MW)	Dispatch Level (MW) Summer Peak Year 2026	2029	2034	Spring Off-Peak 2026
SMUD	Cosumnes Power Plant	ST1	207	192	192	192	192
		CT2	207	184	184	184	184
		CT3	207	184	184	184	184
		Total	**621**	**560**	**560**	**560**	**560**
	Campbell's Soup	CT1	121	110	0	0	0
		ST2	52	53	0	0	0
		Total	**173**	**163**	**0**	**0**	**0**
	Procter & Gamble	CTG-1A	49	42	42	42	42
		CTG-1B	49	42	42	42	0
		STG	42	34	34	34	17
		Total	**140**	**118**	**118**	**118**	**59**
	Carson Ice	CTG1	49	40	40	40	40
		STG	13.7	10	10	10	10
		Total	**62.7**	**50**	**50**	**50**	**50**
	McClellan Peaker	CT	74	65	0	0	0
	Procter & Gamble Peaker	CTG-1C	49	47	47	47	0
	Carson Peaker	CTG2	42	40	40	40	0
	UCD Med Center		27	25	25	25	15
	Total		**1201**	**1068**	**648**	**648**	**684**
MID	Woodland 1	CT	45	43	43	43	0
	Woodland 2 (73 MW Max Total)	CT	48	49	49	49	49
		ST	37	7	7	7	7
	Woodland 3	6	49	38	38	38	31
	McClure Peaker	CT1	53.5	0	0	0	0
		CT2	53.5	0	0	0	0
	Ripon Peaker	CT1	48	35	35	35	0
		CT2	46	0	0	0	0
	Claribel Generation*	CT1	47.97	0	0	0	0
	Total		**415.97**	**172**	**172**	**172**	**87**
RDNG	Redding Power Plant	CT1	18	12.21	12.25	16	0
		CT2	27	17	17	23	0
		CT3	27	17	17	23	0
		ST1	29	27	27	27	0
		CT4	45	40	40	40	0

System	Plant	Unit	Maximum Operating Capacity (MW)	Dispatch Level (MW) Summer Peak Year 2026	2029	2034	Spring Off-Peak 2026
		CT5	45	40	40	40	0
	Total		191	153.21	153.25	169	0
RE	Roseville Energy Park	CT1	47.5	47.5	47.5	47.5	25
		CT2	47.5	47.5	47.5	47.5	25
		ST3	80	70	70	70	30
	Roseville Peaker	CT1	25	20	20	20	0
		CT2	25	20	20	20	0
	DWR Peaker**	CT5	30	27	27	27	0
	DWR Peaker**	CT6	30	27	27	27	0
	Total		**285**	**259**	**259**	**259**	**80**
External	Sutter Energy Center	CT1	175	166.7	83.3	83.3	0
		CT2	175	166.7	83.3	83.3	0
		CT3	175	166.7	83.3	83.3	0
	Total		**525**	**500**	**250**	**250**	**0**

*Note: State of California emergency peaker units.

Table 3.1.6C –Supply-side resources and associated dispatch for the peak and off-peak scenarios (Solar)

System	Plant	Maximum Operating Capacity (MW)	Dispatch Level (MW) Summer Peak Year 2026	2029	2034	Spring Off-Peak 2026
SMUD	Solar Share II	160	112	112	112	112
	Coyote Creek*	250	N/A	0	0	N/A
	Country Acres*	344	N/A	344	344	N/A
	Slough House	50	35	35	35	35
	Wildflower	15.8	13	13	13	13
	Total	**715**	**160**	**504**	**504**	**160**
MID	McHenry Solar Farm	25	16	16	16	17
	Total	**25**	**16**	**16**	**16**	**17**
RDNG	None	0	0	0	0	0
	Total	**0**	**0**	**0**	**0**	**0**
RE	None	0	0	0	0	0
	Total	**0**	**0**	**0**	**0**	**0**

4 Analyses

This assessment included steady state, transient stability and short circuit analyses, which are described in the sections that follow. All simulations performed for the steady state and transient stability portion of this assessment were performed using the General Electric Positive Sequence

Load Flow (PSLF) program. Short circuit studies were performed using Aspen One Liner, CAPE and GE PSLF. These software programs are widely used throughout the WECC.

4.1 Steady State Analysis

A steady state analysis was performed as part of this assessment to determine whether the BANC PC portion of the BES meets the performance requirements specified in the TPL-001-5.1 NERC Reliability Standard for the near and long term planning horizons. The analysis was also performed to assess the impact of extreme events identified in TPL-001-5.1 table 1. This analysis was supported by current studies.

4.1.1 Peak Load Years

This assessment included a steady state analysis of peak loads for planning years two, five, and ten (2026, 2029, and 2034) to span the near-term and long-term planning horizons. Years two (2026) and five (2029) were selected for inclusion in this assessment since they bookend the near-term planning horizon. Year one was not selected since the summer peak load for year one will be less than one year away when this report is finalized. Year ten (2034) was selected for inclusion because it encompasses all approved projects for the long-term planning horizon.

4.1.2 Off-peak Load Years

This assessment included a steady state analysis of off-peak loads for planning year two (2026). Off-peak load is generally defined by BANC PC as spring with a light system load of about 60% of peak, or as uniquely defined by an individual BANC PC participant for their own system, with voltages higher than normal, and generation at a minimum. The off-peak load used in this assessment was determined using engineering judgment and/or historical off-peak spring load data as provided by each BANC PC Participant.

4.1.3 Sensitivity Analysis

This assessment included sensitivity analyses to demonstrate the impact of changes to basic assumptions used in the system models to the steady state reliability. Sensitivity cases for the peak and off-peak load cases were developed by varying the certain conditions in such a way as to stress the system within a range of credible conditions that demonstrated a measurable change in system response.

A sensitivity analysis was performed on the 2026 and 2029 peak load years by using the 1-in-10 year load forecast for the BANC PC area increased by 5% to assess the near-term transmission planning horizon portion of the steady state analysis for MID, RE, RDNG, and SMUD. In accordance with SMUD's Zero Carbon Plan (ZCP), SMUD will be studying an altered generation dispatch for the year 5 (2029) summer peak sensitivity scenario. For the off-peak sensitivity case for year 2026 a reduced generation dispatch with the largest generation plant in each BANC PC participants' area turned off (to stress imports) was chosen. The load power factors in the sensitivity cases were assumed to remain the same. Table 4.1.4.1 lists SMUD's altered generation dispatch for the 2029 peak load sensitivity case.

Table 4.1.4.1 - Thermal generation dispatch used in the SMUD Year 5 (2029) Sensitivity Study Scenario

Plant	Unit	Maximum Operating Capacity (MW)	Dispatch
Cosumnes Power Plant	ST1	207	192
	CT2	207	184
	CT3	207	184
	Total	**621**	**560**
Campbell's Soup	CT1	121	0
	ST2	52	0
	Total	**173**	**0**
Procter & Gamble	CTG-1A	49	0
	CTG-1B	49	0
	STG	42	0
	Total	**140**	**0**
Carson Ice	CTG1	49	0
	STG	13.7	0
	Total	**62.7**	**0**
McClellan Peaker	CT	74	0
Procter & Gamble Peaker	CTG-1C	49	0
Carson Peaker	CTG2	42	0
UCD Med Center		27	25
Sutter Energy Center	CT1	175	83.3
	CT2	175	83.3
	CT3	175	83.3
Total		**1726**	**735**

Table 4.1.4.2 – Solar generation dispatch used in the SMUD Year 5 (2029) Sensitivity Study Scenario

System	Plant	Maximum Operating Capacity (MW)	Dispatch
SMUD	Solar Share II	160	112
	Coyote Creek	250	200
	Elverta Area	500	500
	Slough House	50	35
	Wildflower	15.8	13
	Total	**978**	**860**

*The true generation limits of these plants may be higher than the dispatch level shown in order to meet the maximum POI output after accounting for internal plant losses.

A sensitivity analysis was also performed on the 2026 off peak sensitivity by assuming the power output from the largest generation plant in each participant's area was off-line, which would result in an increase in system imports and a decrease in online spinning generation. Table 4.1.4.3 lists the scenarios for each BANC PC Participant in the sensitivity study base cases.

Table 4.1.4.3 – Spring off-peak sensitivity scenarios

		Scenario	
PC Participant	Element	Off-Peak	Off-Peak Sensitivity
SMUD	Cosumnes Power Plant	510 MW	0 MW
MID	Woodland Power Plant	94 MW	0 MW
RDNG	Redding Power Plant	48 MW	0 MW
RE	Roseville Power Plant	80 MW	0 MW

4.1.4 Known Outages

This assessment included a steady state analysis to assess the impact of known outages of generation or Transmission Facilities planned in the near term horizon in accordance with the "BANC PC Known Outage Analysis Procedure".

4.1.5 Spare Equipment Unavailability Analysis

The respective spare equipment strategies of the BANC PC Participants could result in the unavailability of the following major transmission equipment for one year or more:

- Airport 230/115 kV transformer (RDNG)
- Redding Power Plant 115/13.8 kV GSU (RDNG)

The spare equipment strategies for MID, RE, and SMUD found no major transmission equipment that could result in unavailability for one year or more, due to long lead times.

A steady state analysis was performed for the 2026 peak load case to assess the impact of the possible unavailability of the long lead time equipment listed above. The steady state analysis included the evaluation of the P0, P1, and P2 category contingencies identified in Table 1 of TPL-001-5.1.

4.1.6 Contingencies Studied

The steady state analysis was performed using a comprehensive list of contingencies based on Table 1 of TPL-001-5.1. All possible contingencies for categories P0-P7 were studied for both the steady state and analyses summing to over 14,000 contingencies for SMUD, over 1,300 for MID, over 400 for RE, and over 1,600 for RDNG. P3 and P6 category contingencies were automatically generated by a computer script to cover all possible combinations. In addition, extreme events in Table 1 of TPL-001-5.1 were identified and included in analysis. A summary of the types of contingencies included in the steady state analysis is shown in Table 4.1.6 below.

All contingencies simulated the removal of all elements that the protection system and other automatic controls are expected to disconnect without operator intervention. Generators with post-contingency steady state bus voltages outside the specified ranges provided by each BANC PC Participant were investigated to determine if the generators should be manually tripped to reflect actual protection equipment settings and generator limits (See Table 4.1.7 for the bus voltage criteria). Transmission elements that were overloaded above 150% of their highest seasonal rating (per NERC standard PRC-023-5), were also investigated in accordance with BANC's cascading analysis.

Devices designed to provide steady state control of electrical system quantities, such as phase-shifting transformers, load tap changing transformers, switched capacitors and inductors, were assumed to respond to any contingency after the post-transient contingency analysis time frames of one to three minutes. Therefore, the post-transient solution methodology was utilized, which disabled the adjustment of transmission devices such as phase-shifting transformers, load tap changing transformers, switched capacitors and inductors.

To comply with the TPL-001-5.1, R3.4, contingencies used in this analysis were coordinated with all adjacent PCs and TPs to ensure that contingencies on adjacent systems that may impact the BANC PC portion of the BES were included in this assessment.

Table 4.1.6 – Contingencies Studied in this Assessment (where applicable)

Contingencies	Description
P0 (No contingency)	All Elements in Service
P1 (Single Contingency)	• Loss of one generator (P1.1) • Loss of one transmission circuit (P1.2) • Loss of one transformer (P1.3) • Loss of one shunt or SVC/STATCOM device (P1.4) • Loss of a single pole of DC lines (P1.5)
P2 (Single Contingency)	• Loss of one transmission circuit without a fault (P2.1) • Loss of one bus section (P2.2) • Loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3) • Loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)
P3 (Multiple Contingency)	Loss of a generator unit followed by system adjustments and the loss of the followings: • Loss of one transmission circuit (P1.2) • Loss of one transformer (P1.3) • Loss of one shunt or SVC/STATCOM device (P1.4)
P4 (Multiple Contingency)	Loss of multiple elements caused by a stuck breaker attempting to clear a fault on one of the following: • Loss of one generator (P4.1) • Loss of one transmission circuit (P4.2) • Loss of one transformer (P4.3) • Loss of one shunt device (P4.4) • Loss of one bus section (P4.5) • Loss of a bus-tie-breaker (P4.6)

Contingencies	Description
P5 (Multiple Contingency)[4]	Contingencies with delayed fault clearing due to the failure of a non-redundant component of the protection system protecting the faulted element to operate as designed for one of the following: • Loss of one generator (P5.1) • Loss of one transmission circuit (P5.2) • Loss of one transformer (P5.3) • Loss of one shunt device (P5.4) • Loss of one bus section (P5.5)
P6 (Multiple Contingency)	Loss of two or more (non-generator unit) elements with system adjustment between them, which produce the more severe system results
P7 (Multiple Contingency)	Loss of a common structure as follows: • Any two adjacent circuits on common structure (P7.1) • Loss of a bipolar DC lines (P7.2)
Extreme	Local area or wide area events affecting the Transmission System • Loss of all Transmission lines on a common Right-of-Way • Loss of a substation • Loss of major gas pipeline • Loss of all generating units at a generating station • 3 phase fault with delayed clearing for two adjacent circuits

4.1.7 Performance Requirements

The steady state analysis results for category P0 through P7 contingencies were evaluated against the performance requirements in Table 1 of TPL-001-5.1.

These performance requirements can be summarized as:

- The system shall remain stable.
- Cascading and uncontrolled islanding shall not occur.
- Applicable facility ratings shall not be exceeded.
- Steady state voltages and post-contingency voltage deviations shall be within acceptable limits as established by BANC PC Participants.
- Non-consequential load loss is not allowed for category P1, P2.1, and P3 contingencies.

For the steady state analysis, each BANC PC Participant defined the acceptable limits for steady state voltages and voltage deviations as listed in the Table 4.1.7 below.

Table 1.1.7 – Steady State Voltage Criteria

System	Nominal Voltage	Normal Conditions Vmin (pu)	Normal Conditions Vmax (pu)	Contingency Conditions Vmin (pu)	Contingency Conditions Vmax (pu)	Voltage Deviation P1 & P2.1
SMUD	230 kV	0.948	1.052	0.900[5]	1.052	≤ 8%
	115 kV	0.957	1.078	0.896	1.078	≤ 8%

[5] SMUD 230 kV buses that have a UVLS scheme associated with it are limited to Vmin of 0.948 PU, these buses include Carmichael, Elk Grove, Elverta, Foothill, Hurley, Orangevale, and Pocket.

System	Nominal Voltage	Normal Conditions		Contingency Conditions		Voltage Deviation
		Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	P1 & P2.1
MID	230 kV	0.950	1.050	0.900	1.052	≤ 8%
	115 kV	0.950	1.050	0.900	1.052	≤ 8%
RE	230 kV	1.000	1.057	0.948	1.100	≤ 8%
RDNG	115 kV	0.974	1.078	0.923	1.100	≤ 8%

The criteria used to identify system instability are as follows:

- Cascading – The uncontrolled successive loss of system elements triggered by an incident at any location, and which results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
  - When a post contingency analysis results in steady-state facility loading that is either more than a known BES facility trip setting or exceeds 150 percent of the highest seasonal facility rating for the BES facility studied. If the trip setting is known to be different than the 150 percent threshold, the known setting should be used.
  - When either unrestrained successive load loss occurs, or unrestrained successive generation loss occurs.
- Uncontrolled islanding – The unplanned and uncontrolled splitting of the power system into two or more islands. Severe disturbances may cause uncontrolled separation by causing a group of generators in one area to swing against a group of generators in a different area of the power system.
- Voltage instability – The violation of any of the following WECC voltage criteria.
  - For transfer paths, all P0-P1 events shall demonstrate a positive reactive power margin at a minimum of 105 percent of transfer path flow.
  - For transfer paths, all P2-P7 events shall demonstrate a positive reactive power margin at a minimum of 102.5 percent of transfer path flow.
  - For load areas, all P0-P1 events shall demonstrate a positive reactive power margin at a minimum of 105 percent of forecasted peak load.
  - For load areas, all P2-P7 events shall demonstrate a positive reactive power margin at a minimum of 102.5 percent of forecasted peak load.

Simulations that resulted in cascading, voltage instability, or uncontrolled islanding were deemed unstable.

The results for the extreme contingencies were assessed for their impact to the system. If the results showed cascading caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the events was conducted.

4.2 Short Circuit Analysis

A short circuit analysis addressing the near-term transmission planning horizon was included in this assessment to determine whether circuit breakers have adequate interrupting capability for faults that they will be expected to interrupt.

This analysis was supported by past studies performed by RE, RDNG, and MID. The past studies are qualified since they met the following criteria:

- The past studies are less than five calendar years old.
- No material changes have occurred since the past studies were performed.

The years studied are listed in Table 4.2.

Table 4.2 - Years Studied for Short Circuit Analysis

System	Year Performed	Year(s) Studied
SMUD	2020	2021, 2025
MID	2024	2026, 2030
RDNG	2021	2021, 2026
RE	2022	2022

4.2.1 Simulation Software

The short circuit studies provided by SMUD, RDNG and RE were performed with the ASPEN One Liner and CAPE software programs. MID utilized the GE PSLF software program.

These software programs are widely used throughout the WECC.

4.2.2 Short Circuit Modeling

The short circuit models in the ASPEN program are consistent with the system topology studied in the steady state base cases which reflect the planned projects in Appendix B.

4.2.3 Rating Criteria

The criteria used in the short circuit analysis are based on industry standards developed and approved by the Institute of Electrical and Electronics Engineers in references [2] and [3].

4.3 Stability Analysis

A stability analysis was performed as part of this assessment to assess the transient stability performance of the BANC PC area in the near-term planning horizon. This analysis was supported by current studies.

Although there are no planned material generation additions or changes in the long-term horizon for the BANC PC, the year ten (2034) case was studied to assess potential impacts from neighboring systems.

4.3.1 Peak Load Years

This assessment included a stability analysis of the 2026 peak load year in the near-term planning horizon and year 2034 peak load year in the long-term planning horizon.

The rationale for selecting year two (2026) and year ten (2034) is the same rationale described in Section 4.1.1. Previous study experience has shown that the heavy summer scenario is generally the most critical scenario for transient stability studies. The WECC composite load models, which better represents the dynamic behavior of system loads, were used in this assessment.

4.3.2 Off-peak Load Years

This assessment included a stability analysis of the 2026 off-peak load condition in the near-term planning horizon.

4.3.3 Sensitivity Analysis

Like the steady state sensitivity analysis, two stability sensitivity analyses were performed to demonstrate the impact of changes to basic assumptions used in the system models to the stability of the system.

A sensitivity analysis was performed on the 2026 peak load year by using the 1-in-10 year load forecast for the BANC PC area increased by 5% to assess the near-term transmission planning horizon portion of the stability analysis for MID, RE, RDNG, and SMUD. For the off-peak sensitivity case for year 2026 a reduced generation dispatch with the largest generation plant in each BANC PC participants' area turned off (to stress imports) was chosen. The load power factors in the sensitivity cases were assumed to remain the same.

4.3.4 Known Outages

This assessment included a steady state analysis to assess the impact of known outages of generation or Transmission Facilities planned in the near term horizon in accordance with the "BANC PC Known Outage Analysis Procedure".

4.3.5 Spare Equipment Unavailability Analysis

The respective spare equipment strategies of the BANC PC Participants could result in the unavailability of the following major transmission equipment for one year or more:

- Airport 230/115 kV transformer (RDNG)
- Redding Power Plant 115/13.8 kV GSU (RDNG)

The spare equipment strategies for MID, RE, and SMUD found no major transmission equipment that could result in unavailability for one year or more, due to long lead times.

A steady state analysis was performed for the 2026 peak load case to assess the impact of the possible unavailability of the long lead time equipment listed above. The steady state analysis included the evaluation of the P0, P1, and P2 category contingencies identified in Table 1 of TPL-001-5.1.

4.3.6 Long-Term Planning Horizon

The 2034 heavy summer case was studied for potential impacts from any future facility additions external to the BANC PC area which could have a potential impact on the reliability of the BANC PC area. It was also chosen to encompass any long term transmission projects planned in the BANC PC area. The 10 year case is chosen to encompass any and all projects from neighboring systems that would be submitted to the WECC base case compilation.

4.3.7 Contingencies Studied

A stability analysis was performed based on the contingencies listed in Table 1 of TPL-001-5.1. All P0-P7 contingencies were ran for the stability analyses. In addition, extreme events in Table 1 of TPL-001-5.1 were identified and included in analysis. A summary of the types of stability contingencies evaluated in the stability analysis are shown in Table 4.1.6.

All contingencies simulated the removal of all elements that the protection system and other automatic controls are expected to disconnect without operator intervention. Generators were tripped with the generator under-voltage tripping indicated by the generator protection models, which are included in the WECC approved dynamic models if simulations showed generator bus voltages or high side of the generator step-up voltages outside the ride-through voltage ranges specified in the PRC-024 NERC Reliability Standard. Transmission lines and transformers were tripped using the WECC approved generic relay models when transient swings showed the potential to cause protection system operation as defined under PRC-026[6]. MID is the only BANC PC member that utilizes high speed reclosing in their system, so successful and unsuccessful high speed reclosing were modeled and simulated for the MID system.

All existing devices that are designed to provide dynamic control of electrical system quantities were simulated. These devices include generator exciter control, power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers. The dynamic data used in the stability simulations included (but were not limited to) the modeling of generator governors, exciters, power system stabilizers, and other automatic control equipment.

The contingencies used in the transient stability analysis were coordinated with all adjacent PCs and TPs to ensure that contingencies on adjacent systems which may impact the BANC PC area were included in this assessment.

4.3.8 Performance requirements

The stability analysis results for category P0 through P7 contingencies included in this analysis were evaluated against the performance requirements in Table 1 of TPL-001-5.1. These performance requirements can be summarized as:

- The system shall remain stable.
- Cascading and uncontrolled islanding shall not occur.

[6] Models used to ensure relay performance during stable power swings were GE PSLF models: zonedef (zone definition for WECC distance relay model), distrel (WECC distance relay), zmetra (apparent impedance recorder), lnrelscan (line relay scanning model), lofscan (loss-of-field scanning model), and oosscan (out-of-step scanning model).

- Transient voltage response shall be within acceptable limits as established by the PC and the TP.
- Non-consequential load loss is not allowed for category P1, P2.1, and P3 contingencies on the BANC PC portion of BES.
- For P1 events, no generating unit shall pull out of synchronism.
- For P2 through P7 events, generators that pull out of synchronism shall not cause apparent impedance swings that trip transmission system elements other than the generator unit and its directly connected facilities.
- For P1 through P7 events, power oscillations shall exhibit acceptable damping as established by the PC and the TP.

The results for the extreme contingencies were assessed for their impact to the system based on the above criteria. If the results showed cascading caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the events was conducted.

In accordance with PRC-024, generators are not to trip while their bus voltages remain within the No-Trip zone defined within PRC-024.

The criteria in WR1 of *WECC Criterion TPL-001-WECC-CRT-4 Transmission System Planning Performance* were used to assess the transient stability performance of the system. These criteria are as follows:

- For all P1 through P7 events, voltages shall recover to 80 percent voltage of the pre-contingency voltage within 20 seconds of the initiating event for each applicable BES bus serving load.
- For all P1 through P7 events, following fault clearing and voltage recovery above 80 percent, voltage at each applicable BES bus serving load shall neither dip below 70 percent of pre-contingency voltage for more than 30 cycles nor remain below 80 percent of pre-contingency voltage for more than two seconds.
- For Contingencies without a fault (P2.1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70 percent of precontingency voltage for more than 30 cycles nor remain below 80 percent of precontingency voltage for more than two seconds.

The criterion for acceptable damping for power oscillations, which was adopted from WR1.6 in *WECC Criterion TPL-001-WECC-CRT-4 Transmission System Planning Performance,* was that all oscillations must show positive damping within 30 seconds after the start of the event. Oscillations that did not meet this criterion were deemed unstable.

The criteria used to identify system instability are as follows:

- Cascading – The uncontrolled successive loss of system elements triggered by an incident at any location, and which results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

  - When a post contingency analysis results in steady-state facility loading that is either more than a known BES facility trip setting or exceeds 150 percent of the highest seasonal facility rating for the BES facility studied. If the trip setting is known to be different than the 150 percent threshold, the known setting will be used.
  - When either unrestrained successive load loss occurs, or unrestrained successive generation loss occurs.
- Uncontrolled islanding – The unplanned and uncontrolled splitting of the power system into two or more islands. Severe disturbances may cause uncontrolled separation by causing a group of generators in one area to swing against a group of generators in a different area of the power system.
- Voltage instability – The violation of any of the following WECC voltage criteria.
  - For transfer paths, all P0-P1 events shall demonstrate a positive reactive power margin at a minimum of 105 percent of transfer path flow.
  - For transfer paths, all P2-P7 events shall demonstrate a positive reactive power margin at a minimum of 102.5 percent of transfer path flow.
  - For load areas, all P0-P1 events shall demonstrate a positive reactive power margin at a minimum of 105 percent of forecasted peak load.
  - For load areas, all P2-P7 events shall demonstrate a positive reactive power margin at a minimum of 102.5 percent of forecasted peak load.

Simulations that resulted in cascading, voltage instability, or uncontrolled islanding were deemed unstable.

5 Study Results

The results of the steady state, short circuit, and stability analyses are described in the sections that follow for the BANC PC[7] area.

5.1 Steady State

The steady state analysis identified performance deficiencies for the RDNG and SMUD systems for P6 contingencies, but upon making allowable system adjustments, the performance deficiencies were resolved. There were also previously identified performance deficiencies identified in the SMUD system that have already established remedial action schemes associated with the overloaded facilities. Upon modeling the RAS action, the overloads were mitigated. The performance deficiencies and associated system adjustments for RDNG and SMUD and RAS schemes for SMUD are documented in the results summaries in Appendix C. Descriptions of the RAS actions themselves are housed in SMUD's OP-207 document. There were no performance deficiencies identified for the MID, and RE systems.

[7] BANC PC annual assessment includes performing an assessment for SMUD's non-BES 115 kV elements and WAPA's – SNR portion of the BES to insure reliable operation across the BANC PC area. The results of these studies are available to BANC members and upon request to entities with an NDA.

5.1.1 Corrective Action Plans

There were no new Corrective Action Plans created as a result of this assessment. Below is a list of existing CAPs (if any) as well as the year they were first identified and the planned implementation year:

Table 5.1.1: Currently Active Corrective Action Plans

PC Participant	Project Name	Project Need	Date First Identified	Implementation Status
MID	Westley 230 kV redundant relaying	To prevent an outage of the entire Westley 230 kV substation due to a non-redundant relay failure followed by a fault, which leads to overloads on MID and TID facilities	2021	Approved (February 2025)

5.1.2 Impact of Extreme Contingencies

The steady state analysis identified thermal overloads and voltage criteria violations for certain extreme contingencies. As these are by nature very low probability events, corrective action plans were not developed to mitigate these contingencies.

In the RDNG system, the following contingency would cause multiple 115 kV transmission lines' loading to exceed 150% of their highest emergency rating post-contingency and thus cascading analysis was performed, post-contingency:

- Loss of Keswick-Airport, Flanagan-Keswick, Keswick-Olinda, and Keswick-O'Banion 230 kV lines (RDNG)

The study concluded no cascading or uncontrolled islanding was identified when the affected three lines were tripped. A summary of the steady state study results for extreme contingencies can be referenced in Appendices C and D.

5.1.3 Sensitivity Analysis

No additional thermal overloads or voltage criteria violations other than those identified in the main study scenarios were identified in the sensitivity analyses for RDNG. The sensitivity analyses did identify several additional thermal overloads in the SMUD system for the 2029 HS ZCP sensitivity case. However, since this sensitivity case for SMUD is exploratory and uses system topologies based on a generation fleet comprised of units from its interconnection queue which are currently not approved projects and thus the system model used does not represent actual planned system topology at this time, the criteria violations will not be addressed in this assessment. No voltage criteria violations were identified.

A summary of the steady state sensitivity study results can be referenced in Appendix D.

5.1.4 Spare Equipment Unavailability Analysis

The results of RDNG's Airport 230/115 kV transformer and 115/13.8 kV GSU transformer spare equipment unavailability analyses showed no performance deficiencies. As such, there are no recommendations for the spare equipment strategy.

5.1.5 Known Outage Analysis

The known outage analysis identified one thermal overload following an outage in the SMUD system, however the facility has no currently planned outage. See Appendix F for more information.

5.2 Short Circuit

The short circuit analysis showed that all circuit breakers in the BANC PC area have adequate short circuit current interrupting capabilities and no corrective action plans are necessary to meet the performance requirements. A list of elements that exceeded 80% of their rated fault duty is provided in Appendix H. These elements will be reviewed in future assessments due to their high interrupting duties.

The interrupting capabilities are listed in References [4] to [7].

5.3 Stability

The stability analysis for the peak and off-peak cases did not identify any system deficiencies for the Category P1 to P7 contingencies that were simulated for MID, RDNG, RE, and SMUD. All stability performance criteria were met, and no corrective action plans are necessary to meet the performance requirements.

See Appendix E for sample stability plots. Additional plots are available upon request.

5.3.1 Sensitivity Analysis

The peak load and off-peak load stability sensitivity analyses did not identify any performance deficiencies for the MID, RDNG, RE, and SMUD systems.

5.3.2 Impact of Extreme Contingencies

The stability analysis concluded no cascading was identified following extreme contingencies.

6 Roles and Responsibilities

The PC and Transmission Planners' individual and joint role and responsibilities for performing the required studies for the Planning Assessment are listed in the subsections that follow.

6.1 Joint Roles and Responsibilities

All entities shall be jointly responsible for the following:

- Ensuring the base cases used in the study are accurate. The Planning Coordinator and all Transmission Planners/PC Participants shall endeavor to ensure the models are updated with the latest information for their respective systems.
- Responding to phone and email communications within a reasonable time.
- Working together to resolve differences with respect to study assumptions, modeling, results, or any other issue that may arise during the study.
- Working together to develop Corrective Action Plans when performance criteria violations are deemed valid.

6.2 Individual Roles and Responsibilities

The Planning Coordinator shall be individually responsible for the following:

- Performing all analyses required by NERC TPL-001-5.1, PRC-023, PRC-026, IRO-17 and documenting such analyses.
- Fulfilling other responsibilities that are jointly agreed upon by the Planning Coordinator and Transmission Planners and other PC Participants.

The Transmission Planners and other PC Participants shall be individually responsible for the following:

- Providing all information requested to perform the required studies for the Planning Assessment.
- Performing and providing the results of the short circuit studies.
- Providing a spare equipment unavailability strategy.
- Providing an extreme contingency rationale.
- Providing BANC PC with known outages occurring during the near term horizon.

References

[1] *Transmission System Planning Performance Requirements*. NERC Reliability Standard TPL-001-5.1.1. July 29th, 2020.

[2] *IEEE Application Guide for AC High-Voltage Circuit Breakers Rating on a Symmetrical Current Basis*. IEEE Std. C37.010-1999 (R2005).

[3] *IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers*. IEEE Std. C37.04-1999.

[4] *2020 Breaker Interrupting Study with Appendix.* Sacramento Municipal Utility District. June 28th, 2023.

[5] *2021 RDNG Short Circuit Analysis of 115kV System Results TPL-001.* Redding Electric Utility. March 12th, 2024.

[6] *MID Short Circuit Study 2024_Final.* Modesto Irrigation District. August 5th, 2024.

[7] *RSVL – Breaker Rating Analysis 2022.* Roseville Electric. April, 15th 2022.

[8] *SMUD Operating Procedure OP-207 Sacramento Area DLT, RAS, and Nomogram Operations.* Sacramento Municipal Utility District. May 23rd, 2023.

[9] *Standard PRC-023-4 – Transmission Relay Loadability*. North American Electric Reliability Corporation. November 19th, 2015.

[10] *Standard PRC-024-3 – Frequency and Voltage Protection Settings for Generating Resources*. North American Electric Reliability Corporation. July 9th, 2020.

Appendix A. TPL-001-5.1 Requirement Matrix

The table below lists the TPL-001-5.1 requirements and the associated sections in this assessment that demonstrated compliance.

Table A.1 – Compliance requirements and their corresponding sections and pages

Requirement	Section	Page
R1	3.1	4
R1.1	-	-
R1.1.1	3.1.1	5
R1.1.2	3.1.2	5
R1.1.3	3.1.3	5
R1.1.4	3.1.4	6
R1.1.5	3.1.5	6
R2	-	-
R2.1	4.1	9
R2.1.1	4.1.1	9
R2.1.2	4.1.2	9
R2.1.3	4.1.3	9
R2.1.4	4.1.4	9
R2.1.5	4.1.5	11
R2.2	4.1.1	9
R2.2.1	4.1.1	9
R2.3	4.2, 5.2	15, 21
R2.4	4.3	15
R2.4.1	4.3.1	16
R2.4.2	4.3.2	16
R2.4.3	4.3.3	16
R2.4.4	4.3.4	16
R2.4.5	4.3.5	16
R2.5	4.3.6	17
R2.6	4.2	15
R2.6.1	4.2	15
R2.6.2	4.2	15
R2.7	5	19
R2.7.1	5	19
R2.7.2	5	19
R2.7.3	5	19
R2.7.4	5	19
R2.8	5.2	21
R2.8.1	5.2	21
R2.8.2	5.2	21

Table A.1 continued

Appendix B. Planned Projects

Table B.1 – Planned facilities and changes to existing facilities

PC Participant	Project Name	Project Description	Project Need	Project Status	Expected In-Service Date
MID	Westley 230 kV redundant relaying	Install redundant relaying at the Westley 230 kV substation	To prevent an outage of the entire Westley 230 kV substation due to a non-redundant relay failure followed by a fault.	Approved	End of 2024
	Substation Battery Continuity Monitoring	Installation of open circuit monitoring equipment at MID's substations	To meet the TPL-001-5.1 P5 footnote 13. C. exception.	Approved	2025-2026
RE	DWR Peaker Efficiency Upgrades	Install gas compression and evaporative cooling.	To remove ambient derate effects and increase the incoming gas pressure.	Approved	End of 2025
SMUD	Substation Battery Chargers	Installation of battery chargers at SMUD's substations that are equipped with low DC voltage and open circuit monitoring to meet the TPL-001-5.1 P5 footnote 13	Meet the updated TPL-001-5.1 definition of P5 contingencies and meet the redundancy criteria on our protection system(s).	Approved	Fall 2025
	Slough House Generation Plant	A new 50 MW solar plant connecting to the 69 kV system at the Cordova substation	Not required for criteria violation, was approved as part of the SMUD	Approved	Fall 2025

PC Participant	Project Name	Project Description	Project Need	Project Status	Expected In-Service Date
			2030 Zero Carbon Plan.		
	El Rio Substation Conversion/Expansion	Converting and expanding SMUD's existing single bus, single breaker Elverta 230 kV substation to a breaker and a half scheme.	Not required for criteria violation. Approved to accommodate future renewable generation and load growth.	Approved	December 2026
	El Rio 224 MVA 230/69 kV Transformer	Adding a new 230/69 kV transformer bank to accommodate load growth.	Not required for criteria violation. For future load growth.	Approved	December 2026
	El Rio 250 MVA 230/115 kV Transformer	Replacing existing El Rio 230/115 kV transformer with a 250 MVA transformer.	Not required for criteria violation. For future load growth and to accommodate new generation.	Approved	December 2026
	Country Acres Generation	A new 344 MW Solar combined battery hybrid generation power plant	Not required for criteria violation, was approved as part of the SMUD 2030 Zero Carbon Plan.	Approved	December 2026
	Coyote Creek Generation	A new 250 MW Solar combined battery hybrid generation power plant and accompanying RAS	Not required for criteria violation, was approved as part of the SMUD 2030 Zero Carbon Plan.	Approved	Spring 2027
	Station H 115 kV Substation	A new 115 kV substation in SMUD's downtown area	Not required for criteria violation. For future load growth.	Approved	Summer 2027

PC Participant	Project Name	Project Description	Project Need	Project Status	Expected In-Service Date
	Elverta-Station E Line Clearance Mitigation	Raise the Elverta-Station E 115 kV Line to restore the full cable ratings	Needed to mitigate a thermal overload on the 115 kV system identified in the 2023 TPL assessment as well as prepare for future generation.	Planned	Summer 2027
	UC Davis Medical Center Expansion	Adding a new 115/21 kV transformer at East City to accommodate the UCD load growth	Not required for criteria violation. For future load growth.	Approved	2028-2035
	Station J 115 kV Substation	A new 115 kV substation in SMUD's downtown area	Not required for criteria violation. For future load growth.	Approved	Summer 2030

Appendix C. Steady State Analysis Results

The thermal and voltage results for the peak and off-peak steady state results are listed below.

Table C.1 – The 2026 1-in-10 peak load steady state results

Entity	NERC Category	Contingency	From	kV	To	kV	CK	% Loading	Mitigation
MID	-	None	-	-	-	-	-	-	-
RDNG	P6	Moore - AirportR 115 kV TL outage and Redding Power - Texas Springs 115 kV TL outage	MOORE	115	WALDON	115	#1	105.79	Real time operator will adjust system after initial outage to prepare for second line outage by reducing Redding Power Plant Units 4,5,6 to 70% of present MW output
		Moore - AirportR 115 kV TL outage and Texas Springs - Sulpher Creek 115 kV TL outage	MOORE	115	WALDON	115	#1	100.13	Real time operator will adjust system after initial outage to prepare for second line outage by reducing Redding Power Plant Units 4,5,6 to 70% of present MW output
	Extreme	Keswick - Airport and Flanagan - Keswick and Keswick - Olinda and Keswick - O'Banion 230 kV line outage	OREGON	115	WALDON	115	#1	194.99	Cascading analysis was performed for lines exceeding 150% of their highest rating. In addition, WAPA has an existing operating procedure (OP-057) to mitigate this contingency
			MOORE	115	WALDON	115	#1	169.66	
			KESWICK	115	EUREKA W	115	#2	147.29	
			EUREKA W	115	OREGON	115	#1	136.42	
			KESWICK	115	BELTLINE	115	#1	130.47	
			BELTLINE	115	COLLEGE V	115	#1	104.46	
			AIRPORTR	115	MOORE	115	#1	102.47	
RE	-	None	-	-	-	-	-	-	-
SMUD	P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	CAMINO S	230	LAKE	230	#1	140.77	Operator intervention to prepare system for second outage
	P7	Camino-Lake and Cordova-White Rock 230 kV line outage	ORANGEVL	230	WHITEROK	230	#1	140.42	Existing UARP RAS will mitigate this overload

	Extreme	Rancho Seco 230 kV switching station outage	HEDGE	230	PROCTER	230	#1	126.74	Existing Procter RAS to reduce Hedge-Procter loading. *Overloaded post-RAS action
			*LAKE	230	CORDOVA	230	#1	114.9	
			*CORDOVA	230	HEDGE	230	#1	101.7	
		Loss of all lines north of Lake 230 kV station	ORANGEVL	230	WHITEROK	230	#1	140.5	N/A
		Loss of all lines west of Rancho Seco 230 kV station	HEDGE	230	PROCTER	230	#1	125.15	Existing Procter RAS to reduce Hedge-Procter loading. *Overloaded post-RAS action
			*LAKE	230	CORDOVA	230	#1	115.3	
			*CORDOVA	230	HEDGE	230	#1	101.9	
		Loss of transmission line tower 303	CARMICAL	230	HURLEY S	230	#1	129.78	Existing Carmichael RAS
		Loss of all lines north of Orangevale 230 kV station	CARMICAL	230	HURLEY S	230	#1	129.78	Existing Carmichael RAS
		Loss of all lines north of Natomas 230 kV station	CARMICAL	230	ORANGEVL	230	#1	119.72	N/A
		Loss of all lines south of Elk Grove 230 kV station - B	-	-	-	-	-	DIVERGE	Existing DLT and UVDLT schemes allow case to solve

Table C.2 – The 2026 off peak load steady state results

Entity	NERC Category	Contingency	From	kV	To	kV	CK	% Loading	Mitigation
MID	-	None	-	-	-	-	-	-	-
RDNG	Extreme	Keswick - Airport and Flanagan - Keswick and Keswick - Olinda and Keswick - O'Banion 230 kV line outage	OREGON	115	WALDON	115	#1	146.16	N/A
			MOORE	115	WALDON	115	#1	137.83	N/A
			KESWICK	115	EUREKA W	115	#2	103.67	N/A
RE	-	None	-	-	-	-	-	-	-
SMUD	P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	CAMINO S	230	LAKE	230	#1	140.08	Operator intervention to prepare system for second outage
		Hurley-Procter 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	LAKE	230	FOLSOM	230	#1	105.22	Operator intervention to prepare system for second outage, such as lowering SMUD's hydro generation
		Folsom-Roseville 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	ORANGEVL	230	FOLSOM	230	#1	101.09	Operator intervention to prepare system for second outage, such as lowering SMUD's hydro generation
	P7	Camino-Lake and Cordova-White Rock 230 kV line outage	ORANGEVL	230	WHITEROK	230	#1	139.75	Existing UARP RAS
	Extreme	Loss of all lines north of Lake 230 kV station	ORANGEVL	230	WHITEROK	230	#1	139.78	N/A
		Loss of all lines west of Folsom 230 kV station	HEDGE	230	PROCTER	230	#1	125.35	Existing Procter RAS to reduce Hedge-Procter loading.
			HEDGE	230	CORDOVA	230	#1	106.3	
		Loss of all lines south of Elk Grove 230 kV station - B	GOLDHILL	230	LAKE	230	#1	142.57	N/A

Table C.3 – The 2029 1-in-10 peak load steady state results

Entity	NERC Category	Contingency	From	kV	To	kV	CK	% Loading	Mitigation
MID	-	None	-	-	-	-	-	-	-
RDNG	P6	Moore - AirportR 115 kV TL outage and Redding Power - Texas Springs 115 kV TL outage	MOORE	115	WALDON	115	#1	105.85	Real time operator will adjust system after initial outage to prepare for second line outage by reducing Redding Power Plant Units 4,5,6 to 70% of present MW output
		Moore - AirportR 115 kV TL outage and Texas Springs - Sulpher Creek 115 kV TL outage	MOORE	115	WALDON	115	#1	100.19	Real time operator will adjust system after initial outage to prepare for second line outage by reducing Redding Power Plant Units 4,5,6 to 70% of present MW output
	Extreme	Keswick - Airport and Flanagan - Keswick and Keswick - Olinda and Keswick - O'Banion 230 kV line outage	OREGON	115	WALDON	115	#1	178.61	Cascading analysis was performed for lines exceeding 150% of their highest rating. In addition, WAPA has an existing operating procedure (OP-057) to mitigate this contingency
			MOORE	115	WALDON	115	#1	153.54	
			KESWICK	115	EUREKA W	115	#2	136.08	
			EUREKA W	115	OREGON	115	#1	125.54	
			KESWICK	115	BELTLINE	115	#1	120.88	
RE	-	None	-	-	-	-	-	-	-
SMUD	P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	CAMINO S	230	LAKE	230	#1	140.56	Operator intervention to prepare system for second outage
	P7	Camino-Lake and Cordova-White Rock 230 kV line outage	ORANGEVL	230	WHITEROK	230	#1	140.02	Existing UARP RAS
	Extreme	Rancho Seco 230 kV switching station outage	HEDGE	230	PROCTER	230	#1	153.01	Existing Procter RAS to reduce Hedge-Procter loading.
			*CORDOVA	230	HEDGE	230	#1	110.4	
			*COYOTE CREEK	230	CORDOVA	230	#1	140.2	
			*COYOTE CREEK	230	LAKE	230	#1	140.5	*Overloaded post-RAS action
			HEDGE	230	PROCTER	230	#1	151.31	

		Loss of all lines west of Rancho Seco 230 kV station	*CORDOVA	230	HEDGE	230	#1	110.4	Existing Procter RAS to reduce Hedge-Procter loading. *Overloaded post-RAS action
			*COYOTE CREEK	230	CORDOVA	230	#1	140.5	
			*COYOTE CREEK	230	LAKE	230	#1	140.8	
		Loss of all lines north of Lake 230 kV station	ORANGEVL	230	WHITEROK	230	#1	140.03	Existing Procter RAS to reduce Hedge-Procter loading.
			HEDGE	230	PROCTER	230	#1	113.3	
		Loss of transmission line tower 303	CARMICAL	230	HURLEY S	230	#1	121.28	Existing Carmichael RAS
		Loss of all lines north of Orangevale 230 kV station	CARMICAL	230	HURLEY S	230	#1	121.28	Existing Carmichael RAS
		Loss of all lines north of Natomas 230 kV station	CARMICAL	230	ORANGEVL	230	#1	114.70	N/A
		Loss of all lines south of Elk Grove 230 kV station - B	-	-	-	-	-	DIVERGE	Existing DLT and UVDLT schemes allows case to solve

Table C.4 – The 2034 1-in-10 peak load steady state results

Entity	NERC Category	Contingency	From	kV	To	kV	CK	% Loading	Mitigation
MID	-	None	-	-	-	-	-	-	-
RDNG	P6	Moore - AirportR 115 kV TL outage and Redding Power - Texas Springs 115 kV TL outage	MOORE	115	WALDON	115	#1	119.07	Real time operator will adjust system after initial outage to prepare for second line outage by reducing Redding Power Plant Units 2, 3, 4, 5, 6 to 70% of present MW output.
		Moore - AirportR 115 kV TL outage and Texas Springs - Sulpher Creek 115 kV TL outage	MOORE	115	WALDON	115	#1	113.32	Real time operator will adjust system after initial outage to prepare for second line outage by reducing Redding Power Plant Units 2, 3, 4, 5, 6 to 70% of present MW output.
		AirportW - AirportR 115 kV TL outage and Redding Power - Texas Springs 115 kV TL outage	MOORE	115	WALDON	115	#1	101.13	Real time operator will adjust system after initial outage to prepare for second line outage by reducing Redding Power Plant Units 4,5,6 to 70% of present MW output
	Extreme	Keswick - Airport and Flanagan - Keswick and Keswick - Olinda and Keswick - O'Banion 230 kV line outage	OREGON	115	WALDON	115	#1	195.65	Cascading analysis was performed for lines exceeding 150% of their highest rating. In addition, WAPA has an existing operating procedure (OP-057) to mitigate this contingency
			MOORE	115	WALDON	115	#1	169.52	
			KESWICK	115	EUREKA W	115	#2	148.18	
			EUREKA W	115	OREGON	115	#1	137.08	
			KESWICK	115	BELTLINE	115	#1	133.56	
			AIRPORTR	115	MOORE	115	#1	108.01	
			BELTLINE	115	COLLEGE V	115	#1	106.92	
RE	-	None	-	-	-	-	-	-	-
SMUD	P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	CAMINO S	230	LAKE	230	#1	141.41	Operator intervention to prepare system for second outage
	P7	Camino-Lake and Cordova-White Rock 230 kV line outage	ORANGEVL	230	WHITEROK	230	#1	140.79	Existing UARP RAS
	Extreme	Loss of all lines north of Lake 230 kV station	ORANGEVL	230	WHITEROK	230	#1	140.6	Existing Procter RAS to reduce Hedge-Procter loading.
			HEDGE	230	PROCTER	230	#1	129	

		Loss of transmission line tower 303	CARMICAL	230	HURLEY S	230	#1	118.64	Existing Carmichael RAS
		Loss of all lines north of Orangevale 230 kV station	CARMICAL	230	HURLEY S	230	#1	118.64	Existing Carmichael RAS
		Loss of all lines north of Natomas 230 kV station	CARMICAL	230	ORANGEVL	230	#1	118.27	N/A
		Loss of all lines south of Elk Grove 230 kV station - B	-	-	-	-	-	DIVERGE	Existing DLT and UVDLT schemes allows case to solve
		Loss of all lines west of Rancho Seco 230 kV station	-	-	-	-	-	DIVERGE	Existing DLT and UVDLT schemes allows case to solve
		Rancho Seco 230 kV switching station outage	-	-	-	-	-	DIVERGE	Existing DLT and UVDLT schemes allows case to solve

Appendix D. Steady State Sensitivity Analysis Results

Table D.1 – The 2026 1-in-10 peak load +5% steady state sensitivity results.

Entity	NERC Category	Contingency	From	kV	To	kV	CK	% Loading	Mitigation
MID	-	None	-	-	-	-	-	-	-
RDNG	P6	Moore - AirportR 115 kV TL outage and Redding Power - Texas Springs 115 kV TL outage	MOORE	115	WALDON	115	#1	104.76	Real time operator will adjust system after initial outage to prepare for second line outage by reducing Redding Power Plant Units 4,5,6 to 70% of present MW output
	Extreme	Keswick - Airport and Flanagan - Keswick and Keswick - Olinda and Keswick - O'Banion 230 kV line outage	OREGON	115	WALDON	115	#1	194.57	Cascading analysis was performed for lines exceeding 150% of their highest rating. In addition, WAPA has an existing operating procedure (OP-057) to mitigate this contingency
			MOORE	115	WALDON	115	#1	167.87	
			KESWICK	115	EUREKA W	115	#2	147.88	
			EUREKA W	115	OREGON	115	#1	136.58	
			KESWICK	115	BELTLINE	115	#1	130.17	
			BELTLINE	115	COLLEGE V	115	#1	103.94	
			AIRPORTR	115	MOORE	115	#1	100.6	
RE	-	None	-	-	-	-	-	-	-
SMUD	P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	CAMINO S	230	LAKE	230	#1	141.03	N/A
	P7	Camino-Lake and Cordova-White Rock 230 kV line outage	ORANGEVL	230	WHITEROK	230	#1	140.72	N/A
	Extreme	Rancho Seco 230 kV switching station outage	HEDGE	230	PROCTER	230	#1	140.74	N/A
		Loss of all lines north of Lake 230 kV station	ORANGEVL	230	WHITEROK	230	#1	140.85	N/A
		Loss of all lines west of Rancho Seco 230 kV station	HEDGE	230	PROCTER	230	#1	138.65	N/A
		Loss of transmission line tower 303	CARMICAL	230	HURLEY S	230	#1	136.57	N/A
		Loss of all lines north of Orangevale 230 kV station	CARMICAL	230	HURLEY S	230	#1	136.57	N/A

		Loss of all lines north of Natomas 230 kV station	CARMICAL	230	ORANGEVL	230	#1	117.27	N/A
		Loss of all lines south of Elk Grove 230 kV station - A	CAMPBELL	230	HEDGE	230	#1	102.99	N/A
		Loss of all lines south of Elk Grove 230 kV station - B	-	-	-	-	-	DIVERGE	Existing DLT and UVDLT schemes allows case to solve

Table D.2 – The 2026 off peak load steady state sensitivity results.

Entity	NERC Category	Contingency	From	kV	To	kV	CK	% Loading	Mitigation
MID	-	None	-	-	-	-	-	-	-
RDNG	Extreme	Keswick - Airport and Flanagan - Keswick and Keswick - Olinda and Keswick - O'Banion 230 kV line outage	OREGON	115	WALDON	115	#1	146.4	N/A
			MOORE	115	WALDON	115	#1	138.04	
			KESWICK	115	EUREKA W	115	#2	103.85	
RE	-	None	-	-	-	-	-	-	-
SMUD	P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	CAMINO S	230	LAKE	230	#1	141.05	-
	P7	Camino-Lake and Cordova-White Rock 230 kV line outage	ORANGEVL	230	WHITEROK	230	#1	140.66	N/A
	Extreme	Loss of all lines north of Lake 230 kV station	ORANGEVL	230	WHITEROK	230	#1	140.84	N/A
		Loss of all lines west of Folsom 230 kV station	HEDGE	230	CORDOVA	230	#1	112.25	N/A
		Hurley-Tracy #1 and #2 and Bellota-Rancho Seco #1 and #2 230 kV line outage	GOLDHILL	230	LAKE	230	#1	114.58	N/A
		Loss of all lines south of Elk Grove 230 kV station - B	-	-	-	-	-	DIVERGE	Existing DLT and UVDLT schemes allows case to solve

Table D.3 – The 2029 1-in-10 +5% peak load steady state sensitivity results.

Entity	NERC Category	Contingency	From	kV	To	kV	CK	% Loading	Mitigation
MID	-	None	-	-	-	-	-	-	-
RDNG	P6	Moore - AirportR 115 kV TL outage and Redding Power - Texas Springs 115 kV TL outage	MOORE	115	WALDON	115	#1	104.77	Real time operator will adjust system after initial outage to prepare for second line outage by reducing Redding Power Plant Units 4,5,6 to 70% of present MW output
	Extreme	Keswick - Airport and Flanagan - Keswick and Keswick - Olinda and Keswick - O'Banion 230 kV line outage	OREGON	115	WALDON	115	#1	178.08	Cascading analysis was performed for lines exceeding 150% of their highest rating. In addition, WAPA has an existing operating procedure (OP-057) to mitigate this contingency
			MOORE	115	WALDON	115	#1	151.69	
			KESWICK	115	EUREKA W	115	#2	136.56	
			EUREKA W	115	OREGON	115	#1	125.61	
			KESWICK	115	BELTLINE	115	#1	120.47	
RE	-	None	-	-	-	-	-	-	-

Table D.4 – The 2029 SMUD ZCP steady state sensitivity results.

Entity	NERC Category	Contingency	From	kV	To	kV	CK	% Loading
SMUD	P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	CAMINO S	230	LAKE	230	#1	140.76
	P7	Camino-Lake and Cordova-White Rock 230 kV line outage	ORANGEVL	230	WHITEROK	230	#1	140.35
	Extreme	Loss of all lines north of Natomas 230 kV station	CARMICAL	230	ORANGEVL	230	#1	146.65
			CARMICAL	230	HURLEY S	230	#1	104.67
			ORANGEVL	230	COUNTRYACRE S	230	#1	103.1
		Loss of all lines north of Lake 230 kV station	ORANGEVL	230	WHITEROK	230	#1	140.46
			CARMICAL	230	ORANGEVL	230	#1	102.92
		Rancho Seco 230 kV switching station outage	HEDGE	230	PROCTER	230	#1	139.32
			CORDOVA	230	COYOTECREEK	230	#1	120.96
		Loss of all lines west of Rancho Seco 230 kV station	HEDGE	230	PROCTER	230	#1	137.5
			CORDOVA	230	COYOTECREEK	230	#1	121.62
		Loss of transmission line tower 303	CARMICAL	230	HURLEY S	230	#1	121.96

Appendix E. Spare Equipment Unavailability Analysis

Table E.1 – Redding GSU Transformer Spare Equipment Unavailability Analysis

NERC Category	Contingency	From	kV	To	kV	CK	% Loading	Mitigation
-	None	-	-	-	-	-	-	-

Table E.2 – Redding Airport Transformer Spare Equipment Unavailability Analysis

NERC Category	Contingency	From	kV	To	kV	CK	% Loading	Mitigation
-	None	-	-	-	-	-	-	-

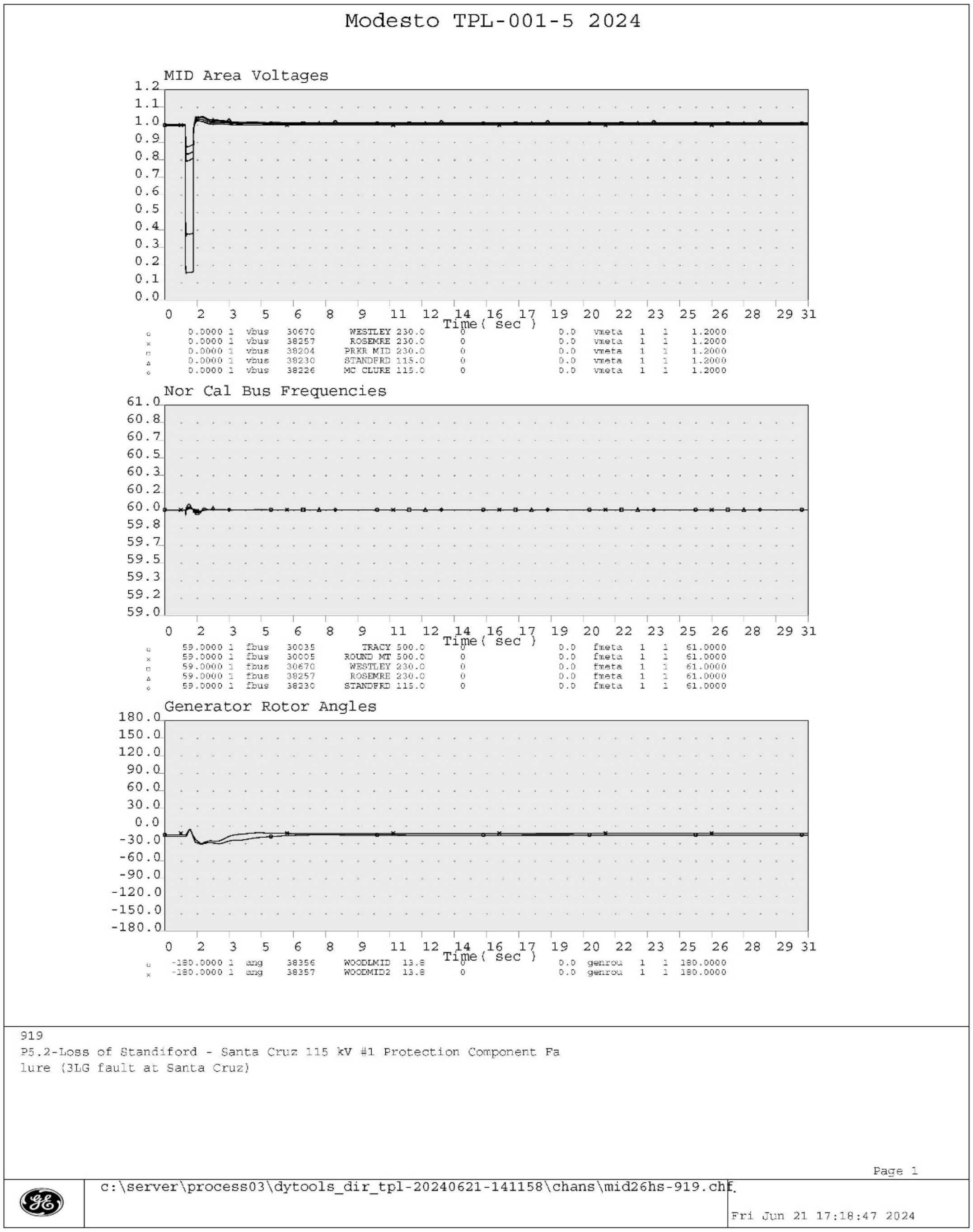
Appendix F: Known Outage Analysis

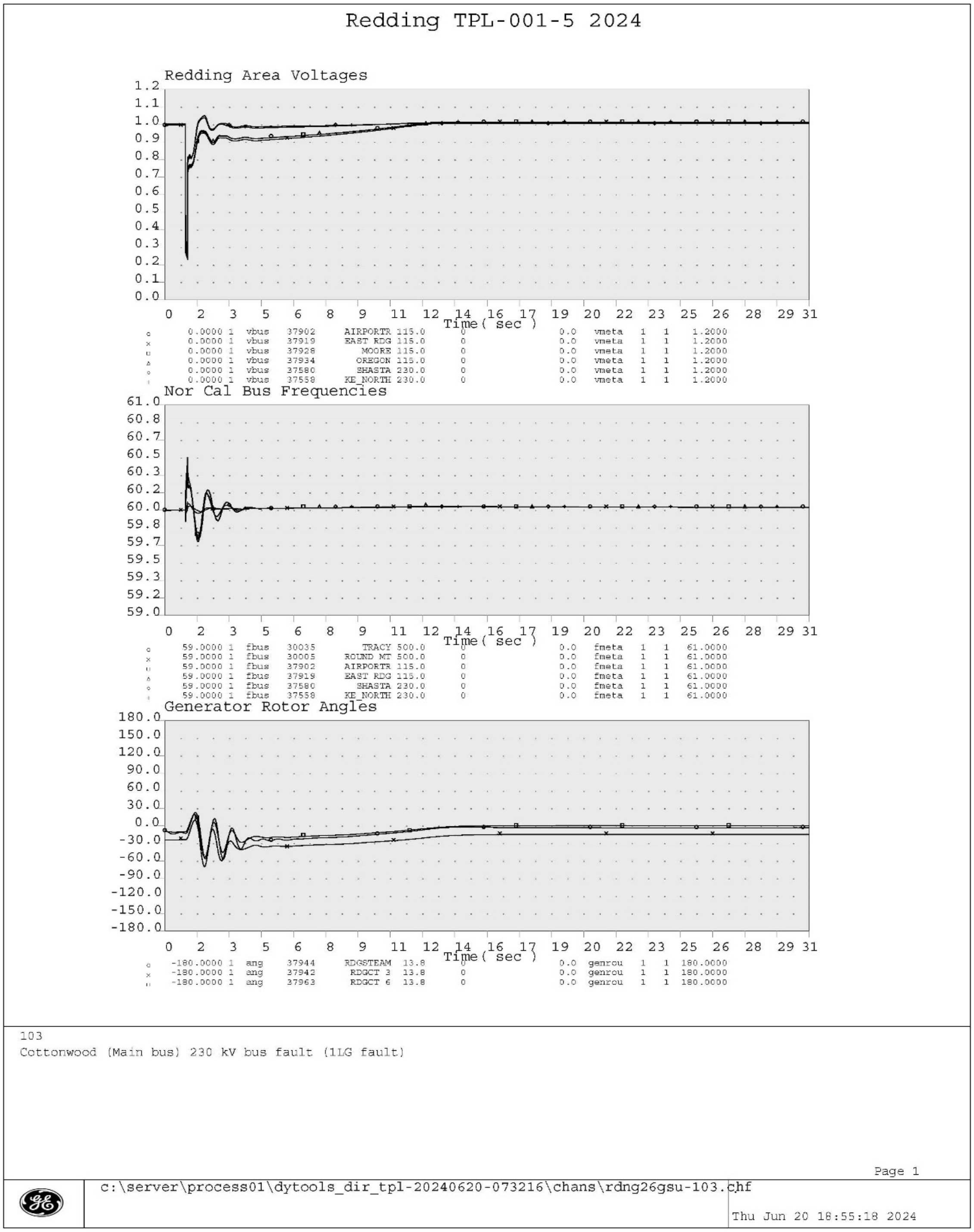
Table F.1 – 2026 Known Outage Analysis

Entity	Facility Outage	From	kV	To	kV	CK	% Loading	Mitigation
SMUD	Natomas-O'Banion 230 kV TL Outage	NATOMAS	230	HURLEY	230	1	103%	This facility currently has no planned outage associated with it, so no mitigation is required.

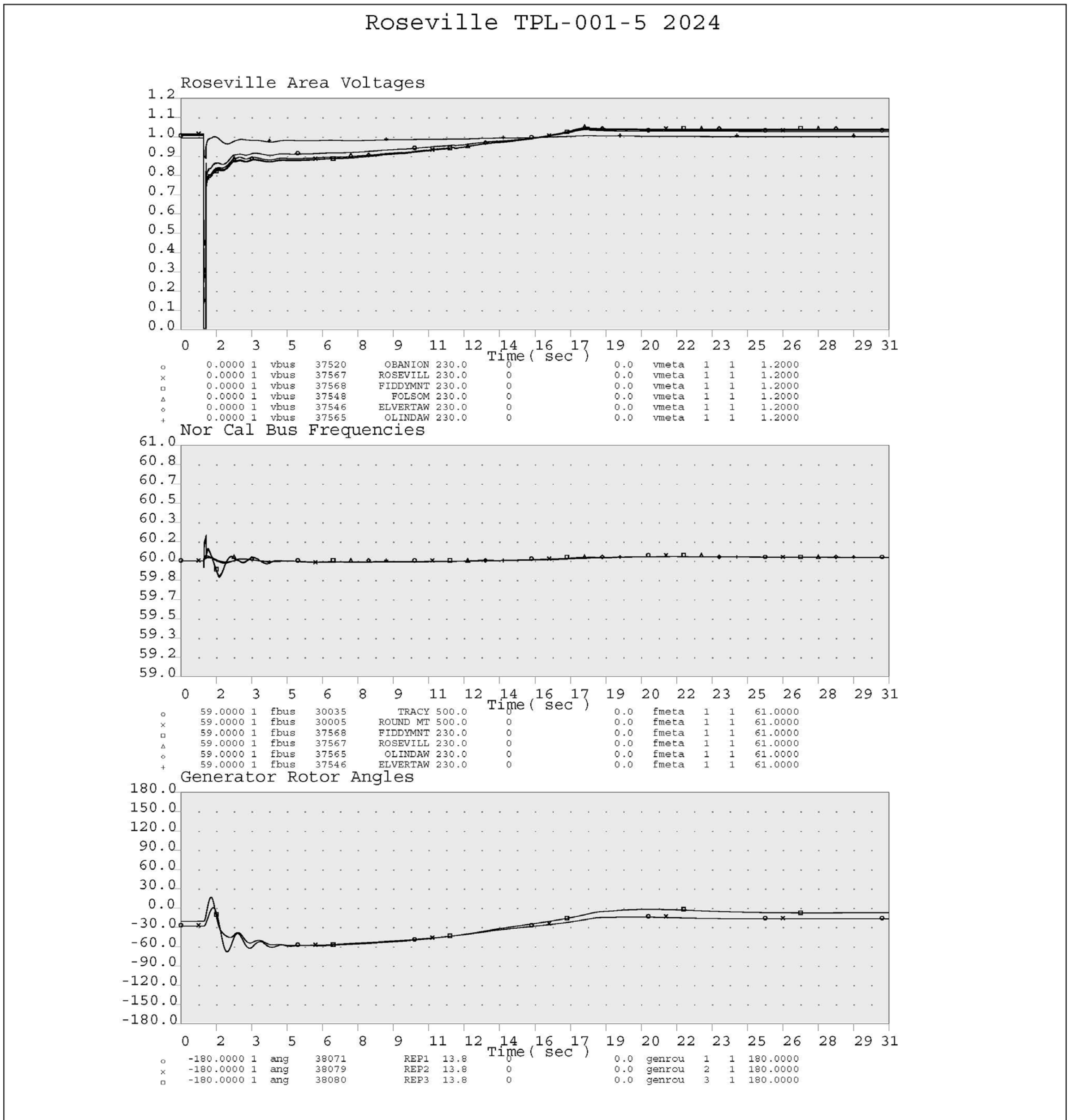
Appendix G. Sample Transient Stability Plots

Sample plots for each PC Participant are shown below. Where possible, more extreme responses were shown.





Redding TPL-001-5 2024
Redding Area Voltages
Time(sec)
0.0000 1 vbus 37902 AIRPORTR 115.0 0 0.0 vmeta 1 1 1.2000
0.0000 1 vbus 37919 EAST RDG 115.0 0 0.0 vmeta 1 1 1.2000
0.0000 1 vbus 37928 MOORE 115.0 0 0.0 vmeta 1 1 1.2000
0.0000 1 vbus 37934 OREGON 115.0 0 0.0 vmeta 1 1 1.2000
0.0000 1 vbus 37580 SHASTA 230.0 0 0.0 vmeta 1 1 1.2000
0.0000 1 vbus 37558 KE_NORTH 230.0 0 0.0 vmeta 1 1 1.2000
Nor Cal Bus Frequencies
Time(sec)
59.0000 1 fbus 30035 TRACY 500.0 0 0.0 fmeta 1 1 61.0000
59.0000 1 fbus 30005 ROUND MT 500.0 0 0.0 fmeta 1 1 61.0000
59.0000 1 fbus 37902 AIRPORTR 115.0 0 0.0 fmeta 1 1 61.0000
59.0000 1 fbus 37919 EAST RDG 115.0 0 0.0 fmeta 1 1 61.0000
59.0000 1 fbus 37580 SHASTA 230.0 0 0.0 fmeta 1 1 61.0000
59.0000 1 fbus 37558 KE_NORTH 230.0 0 0.0 fmeta 1 1 61.0000
Generator Rotor Angles
Time(sec)
-180.0000 1 ang 37944 RDGSTEAM 13.8 0 0.0 genrou 1 1 180.0000
-180.0000 1 ang 37942 RDGCT 3 13.8 0 0.0 genrou 1 1 180.0000
-180.0000 1 ang 37963 RDGCT 6 13.8 0 0.0 genrou 1 1 180.0000
103
Cottonwood (Main bus) 230 kV bus fault (1LG fault)
Page 1
c:\server\process01\dytools_dir_tpl-20240620-073216\chans\rdng26gsu-103.chf
Thu Jun 20 18:55:18 2024

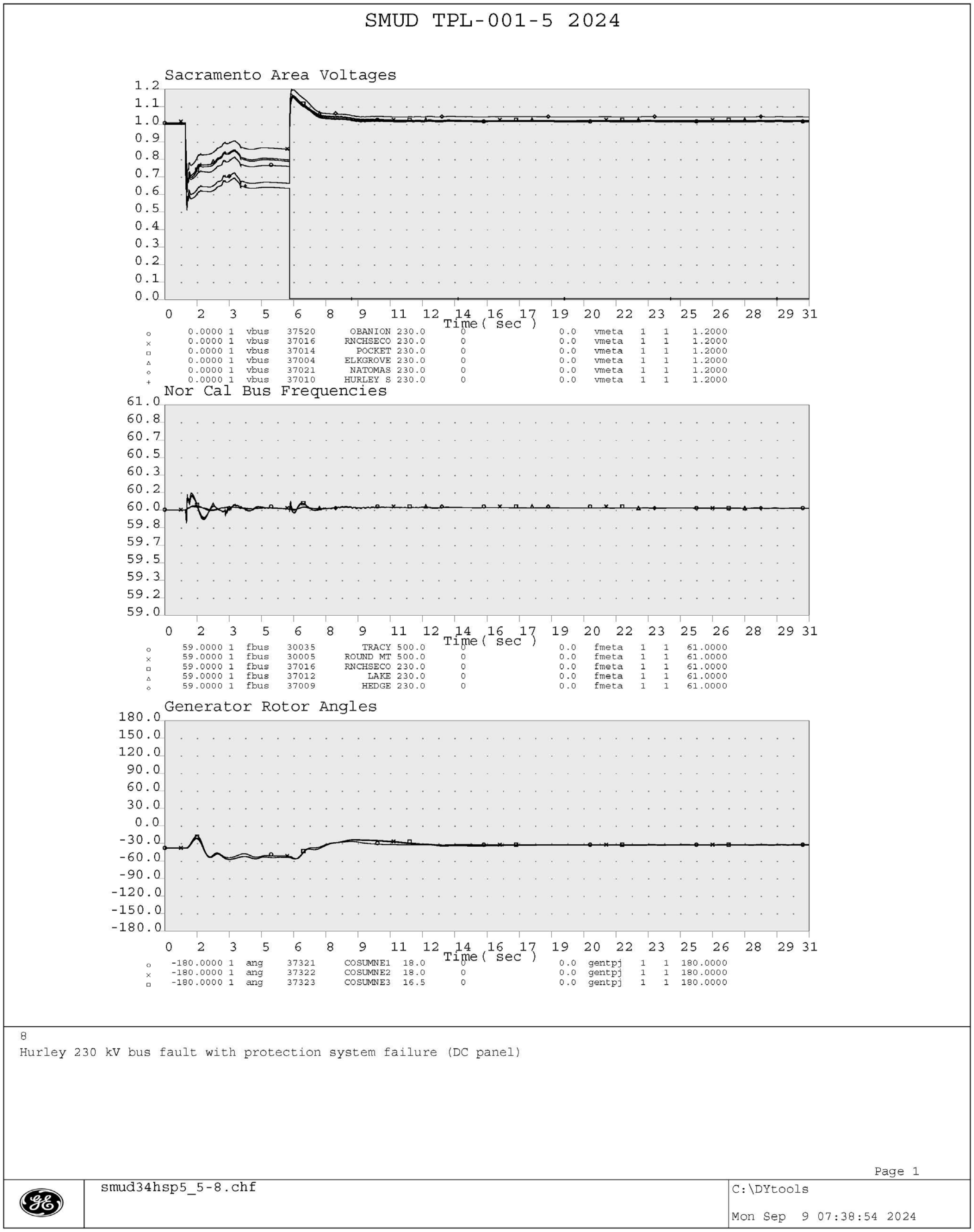


344
Cottonwood - Roseville 230kV TL outage and Roseville #1 230/60 kV TX o
tage (3LG fault on high side)

Page 1

c:\server\process03\dytools_dir_tpl-20240618-111524\chans\rsvl29hs-344.chf

Tue Jun 18 16:56:11 2024


SMUD TPL-001-5 2024
Sacramento Area Voltages
1.2
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0 2 3 5 6 8 9 11 12 14 16 17 19 20 22 23 25 26 28 29 31
Time(sec)
0.0000 1 vbus 37520 OBANION 230.0 0 0.0 vmeta 1 1 1.2000
0.0000 1 vbus 37016 RNCHSECO 230.0 0 0.0 vmeta 1 1 1.2000
0.0000 1 vbus 37014 POCKET 230.0 0 0.0 vmeta 1 1 1.2000
0.0000 1 vbus 37004 ELKGROVE 230.0 0 0.0 vmeta 1 1 1.2000
0.0000 1 vbus 37021 NATOMAS 230.0 0 0.0 vmeta 1 1 1.2000
0.0000 1 vbus 37010 HURLEY S 230.0 0 0.0 vmeta 1 1 1.2000
Nor Cal Bus Frequencies
61.0
60.8
60.7
60.5
60.3
60.2
60.0
59.8
59.7
59.5
59.3
59.2
59.0
0 2 3 5 6 8 9 11 12 14 16 17 19 20 22 23 25 26 28 29 31
Time(sec)
59.0000 1 fbus 30035 TRACY 500.0 0 0.0 fmeta 1 1 61.0000
59.0000 1 fbus 30005 ROUND MT 500.0 0 0.0 fmeta 1 1 61.0000
59.0000 1 fbus 37016 RNCHSECO 230.0 0 0.0 fmeta 1 1 61.0000
59.0000 1 fbus 37012 LAKE 230.0 0 0.0 fmeta 1 1 61.0000
59.0000 1 fbus 37009 HEDGE 230.0 0 0.0 fmeta 1 1 61.0000
Generator Rotor Angles
180.0
150.0
120.0
90.0
60.0
30.0
0.0
-30.0
-60.0
-90.0
-120.0
-150.0
-180.0
0 2 3 5 6 8 9 11 12 14 16 17 19 20 22 23 25 26 28 29 31
Time(sec)
-180.0000 1 ang 37321 COSUMNE1 18.0 0 0.0 gentpj 1 1 180.0000
-180.0000 1 ang 37322 COSUMNE2 18.0 0 0.0 gentpj 1 1 180.0000
-180.0000 1 ang 37323 COSUMNE3 16.5 0 0.0 gentpj 1 1 180.0000
8
Hurley 230 kV bus fault with protection system failure (DC panel)
Page 1
smud34hsp5_5-8.chf
C:\DYtools
Mon Sep 9 07:38:54 2024

Appendix H. Short Circuit Results

Table F.1 – List of Short Circuit elements that exceed 80% duty.

PC Participant	Element	Fault Type	Year	Facility Rating (A)	Duty (A)	Duty (%)
SMUD	Hurley CB 5814	2LG	2021	35,369	30,664	86.7
	Hurley CB 5820	2LG	2021	35,369	32,291	91.3
	Hurley CB 5834	2LG	2021	35,369	32,787	93.0
MID	Westley CB 2354	3Ø	2026/ 2030	40,000	38,884/ 39,477	97.21/ 98.69
	Westley CB 2355	3Ø	2026/ 2030	40,000	38,884/ 39,477	97.21/ 98.69
	Westley CB 2356	3Ø	2026/ 2030	40,000	38,884/ 39,477	97.21/ 98.69
RDNG	None					
RE	None					

Appendix I. Version History

Version	Change(s)	By	Date
0.0	Initial draft	Ryan Price	9/9/2024
1.0	PC Participant Comments	Ryan Price	9/24/2024

Balancing Authority of Northern California
Resolution 24-11-01

ACKNOWLEDGEMENT AND ACCEPTANCE OF BANC PLANNING COORDINATOR AREA 2024 TRANSMISSION PLANNING ASSESSMENT

WHEREAS, the Balancing Authority of Northern California ("BANC") was created by a Joint Powers Agreement ("JPA") to, among other things, acquire, construct, maintain, operate, and finance Projects; and

WHEREAS, BANC is the NERC Planning Coordinator ("PC") for four of its members, including the Sacramento Municipal Utility District ("SMUD"), Modesto Irrigation District ("MID"), Redding Electric Utility ("REU"), and Roseville Electric; and

WHEREAS, BANC must demonstrate compliance with certain PC-related NERC reliability standards, including TPL-001-5; and

WHEREAS, in order to meet this standard, SMUD, as the PC Services Provider, produced the BANC PC Area 2024 Transmission Planning Assessment ("Assessment"), in which the performance of the BANC PC area was assessed in order to demonstrate that its portion of the Bulk Electric System meets all of the performance requirements specified in the above-mentioned standard for the years 2025 through 2034; and

WHEREAS, the Assessment concludes that no new system deficiencies or criteria violations were identified for the MID and Roseville Electric portions of the BES, and that, while contingencies were identified for the REU and SMUD portions of the BES, these can be mitigated with allowable system adjustments in between outages, so no corrective active plans were developed per this assessment; and

WHEREAS, each PC Committee member concurred with the Assessment on or before October 4th.

NOW, THEREFORE, BE IT RESOLVED that the Commissioners of the Balancing Authority of Northern California hereby acknowledge and accept the Assessment.

PASSED AND ADOPTED by the Commissioners of the Balancing Authority of Northern California this 20th day of November, 2024, by the following vote:

		Aye	No	Abstain	Absent
Modesto ID	Martin Caballero				
City of Redding	Nick Zettel				
City of Roseville	Dan Beans				
City of Shasta Lake	James Takehara				
SMUD	Paul Lau				
TPUD	Paul Hauser				

Paul Hauser
Chair

Attest by: C. Anthony Braun
Secretary

Balancing Authority of Northern California

Agenda Item 5B

1. **Resolution 24-11-02** ***Resolution Setting the Regular Meeting Dates for 2025*****.**
2. **Attachment A to Resolution 24-11-02:** ***Time and Place of Regular Meetings for 2025*****.**

Balancing Authority of Northern California
Resolution 24-11-02

RESOLUTION SETTING THE REGULAR MEETING DATES FOR 2025

WHEREAS, the Balancing Authority of Northern California ("BANC") was created by a Joint Powers Agreement ("JPA") to, among other things, acquire, construct, maintain, operate, and finance Projects; and

WHEREAS, JPA Section 11.2 provides that the BANC Commission may provide for the holding of regular meetings at intervals more frequently than annually; and

WHEREAS, JPA Section 11.2 requires that the date, hour, and place of each regular meeting shall be fixed by resolution of the Commission.

NOW, THEREFORE, BE IT RESOLVED that the Commissioners of the Balancing Authority of Northern California hereby approve the 2025 Regular Meeting Schedule, attached hereto as Attachment A.

PASSED AND ADOPTED by the Commissioners of the Balancing Authority of Northern California this 20th day of November, 2024, by the following vote:

		Aye	No	Abstain	Absent
Modesto ID	Martin Caballero				
City of Redding	Nick Zettel				
City of Roseville	Dan Beans				
City of Shasta Lake	James Takehara				
SMUD	Paul Lau				
TPUD	Paul Hauser				

____
Paul Hauser
Chair

____
Attest by: C. Anthony Braun
Secretary

Time and Place of Regular Meetings for 2025

Unless shown otherwise, the Regular Commission meetings shall occur on the fourth Wednesday of each month, at 2:00 p.m.

As shall be specified in a notice issued pursuant to the Ralph M. Brown Act of the California Government Code, the meetings listed below will be held in Sacramento, California at 555 Capitol Mall. Room location to be provided on posted agenda.

1. **January 29**
2. **March 26**
3. **April 23**
4. **May 28**
5. **June 25**
6. **July 23**
7. **August 27**
8. **December 17**

The meetings on the dates listed below will be held in Gold River, California at 2377 Gold Meadow Way, 1st Floor Conference Room.

1. **February 19**
2. **September 17**
3. **October 22**
4. **November 19**

The Commission Secretary shall have discretion to adjourn and to modify time and location of Commission meetings consistent with posting requirements of the Ralph M. Brown Act of the California Government Code.

Balancing Authority of Northern California

Agenda Item 5C

1. **Resolution 24-11-03 *Approval of BANC Internal Compliance Program Charter – 2024 Updates*.**
2. **Attachment A to Resolution 24-11-03: BANC Internal Compliance Program Charter, Version 9.0.**
3. **BANC Member Compliance Review Committee Charter, Version 9.0.**

Braun Blaising & Wynne, P.C.
Attorneys at Law

11/14/24

To: **BANC Commission**

From: **BANC Counsel**

RE: **Approval of BANC Internal Compliance Program Charter**

The Compliance Officer is seeking Commission approval of the revisions made to the Balancing Authority of Northern California ("BANC") Internal Compliance Program ("ICP") Charter ("ICPC"). The prior review and revision, Version 8, occurred in September of 2023. ICPC Version 9 is being provided to the Commission for review and approval.

Background

The BANC ICP is comprised of both policy-level and program-level components. The document before the Commission is the ICPC, which outlines the policy-level component of the ICP. The ICPC provides the overall policy framework for the ICP. Commission consideration and approval of the ICPC helps demonstrate an active oversight of the ICP.

The ICP implementation details are outlined in separate program-level documents, including the Member Compliance Review Committee ("MCRC") Charter, found in Appendix A of the ICPC, the North American Electric Reliability Corporation ("NERC") Compliance Monitoring and Enforcement Program Implementation Plan ("CMEP-IP"), and a detailed compliance program components document, which serves as the manual for the ongoing day-to-day processes and procedures related to implementing and managing the ICP. These program-level working documents, while entirely consistent with ICPC policies, are not separately approved by the Commission.

Summary of ICPC Changes

The ICPC changes are undertaken annually, as part of an annual documents review that was originally recommended by Sacramento Municipal Utility District's ("SMUD") Internal Audit Services ("IAS") team. Regular audits of the compliance program are conducted by IAS, and WECC conducts triennial audits as a part of its CMEP activities. Regular updates of compliance documents are an important part of the preparation for these activities.

In this review cycle, minor ICPC updates and administrative changes were made, including:

- Updates to conform with changes made to the NERC Rules of Procedure, WECC's CMEP-IP and/or other Compliance Enforcement Authority guidance, including:
  - Removal of outdated terms, such as 'NERC Functional Model' (replaced by 'Rules of Procedure'), 'compliance application notices/reports' (removed), and 'ICE process' (replaced by 'internal controls review process')
  - Modifications to footnotes to ensure the correct document sections are referenced
  - Updates to hyperlinks to match updates made to regulators' websites
- Minor, non-substantive formatting updates, including updates to version number & update date throughout

Conforming changes were also made to the MCRC Charter (Appendix A to the BANC Internal Compliance Program Charter), and a copy is being provided for your information:

- Minor, non-substantive formatting updates (numbering correction in section 6.2.1.1)
- Updates to version number & update date throughout

<u>Conclusion</u>

The ICPC has been reviewed and accepted by the MCRC, which includes representatives from each of the BANC member organizations and the Western Area Power Administration – Sierra Nevada Region. We are seeking Commission approval of these changes. A clean approval draft of Version 9 of the ICPC has been included as Attachment A to Resolution 24-11-03 *Approval BANC Internal Compliance Program Charter – 2024 Updates*.

Balancing Authority of Northern California
Resolution 24-11-03

Approval of BANC Internal Compliance Program Charter – 2024 Updates

WHEREAS, the Balancing Authority of Northern California (“BANC”) maintains an Internal Compliance Program (“ICP”) to ensure compliance with North American Electric Reliability Corporation (“NERC”) Reliability Standards (“Standards”); and

WHEREAS, the Commission has adopted the BANC ICP Charter (“ICPC”) to establish its policies relating to the ICP; and

WHEREAS, the Compliance Officer, in consultation with the Member Compliance Review Committee (“MCRC”), periodically reviews and proposes revisions to the ICPC to ensure the ICP is aligned with changes and/or revisions to Standards and/or changes in BANC’s obligations thereto; and

WHEREAS, the Compliance Officer has proposed revisions to the ICPC, referred to as ICPC Version 9, primarily to address administrative updates and ensure alignment with other NERC and WECC documentation; and

WHEREAS, the MCRC has reviewed and has concurred with the proposed ICPC revisions.

NOW, THEREFORE, BE IT RESOLVED that the Commissioners of the Balancing Authority of Northern California hereby acknowledge and approve the ICPC, attached hereto as Attachment A.

PASSED AND ADOPTED by the Commissioners of the Balancing Authority of Northern California this 20th day of November 2024, by the following vote:

		Aye	No	Abstain	Absent
Modesto ID	Martin Caballero				
City of Redding	Nick Zettel				
City of Roseville	Dan Beans				
City of Shasta Lake	James Takehara				
SMUD	Paul Lau				
TPUD	Paul Hauser				

Paul Hauser
Chair

Attest by: C. Anthony Braun
Secretary

BALANCING AUTHORITY OF NORTHERN CALIFORNIA

Internal Compliance Program Charter

Version 9.0

BANC Members:

Modesto Irrigation District (MID)
City of Redding (REU)
City of Roseville
City of Shasta Lake
Sacramento Municipal Utility District (SMUD)
Trinity Public Utilities District (TPUD)

Internal Compliance Program Charter

TABLE OF CONTENTS

Section 1. Overview

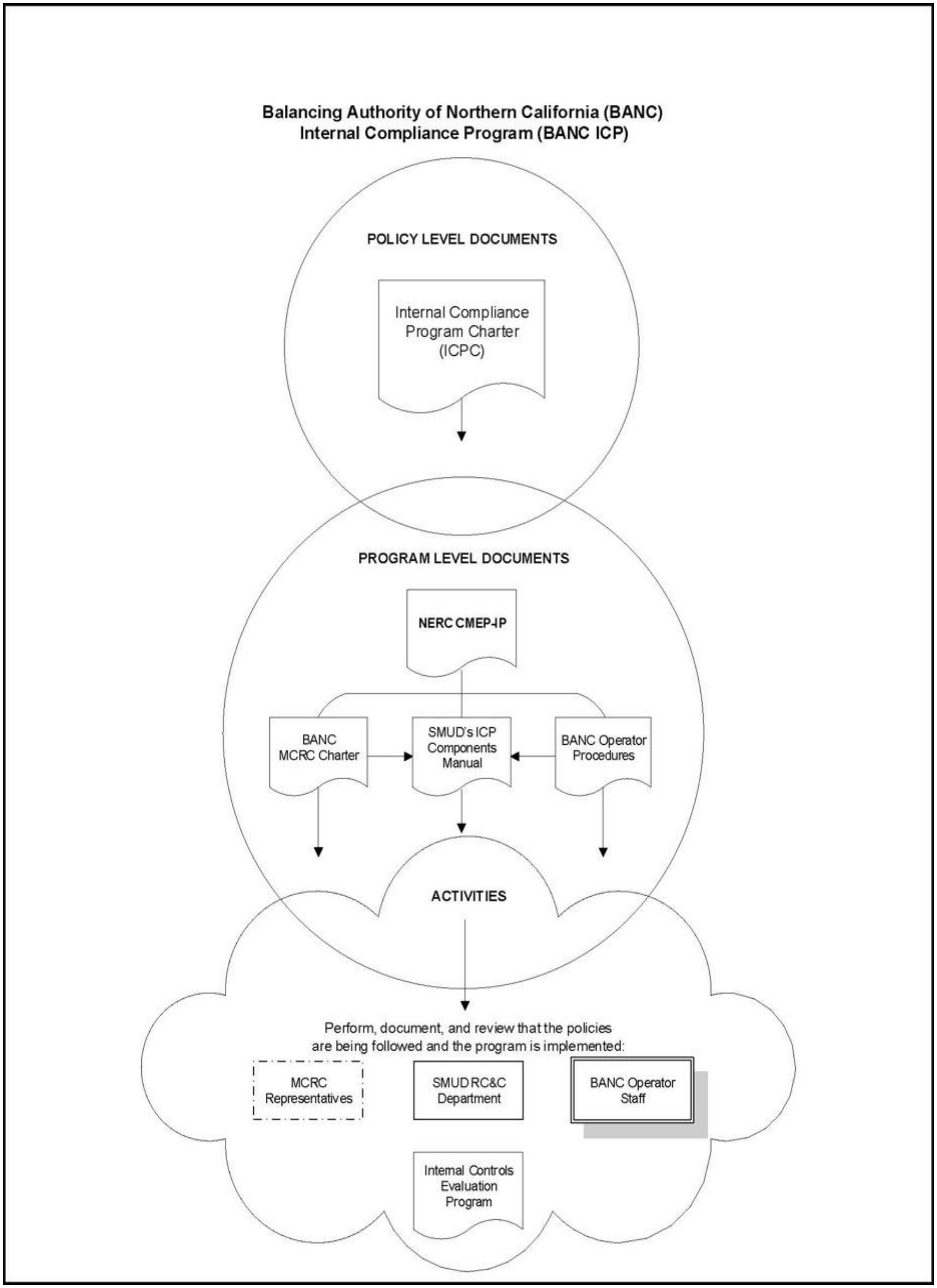
The Balancing Authority of Northern California (BANC) Internal Compliance Program (ICP) is comprised of two types of component documents: (1) policy-level; and (2) program-level. This document outlines the first, policy-level component of the ICP, referred to as the "Internal Compliance Program Charter" (ICPC). Developed by the Compliance Officer and approved by the BANC Commission, the ICPC provides the overall policy framework for the ICP. The ICP implementation details are outlined in separate program-level documents, including: the BANC Member Compliance Review Committee (MCRC) Charter, found in Appendix A; the North American Electric Reliability Corporation (NERC) Compliance Monitoring and Enforcement Program Implementation Plan (CMEP-IP); the SMUD Internal Controls Evaluation Program (ICE Program); and the SMUD Reliability Internal Compliance Program Components Manual.

The ICPC has been reviewed by the MCRC and provided to Compliance Staff and Subject Matter Experts (SMEs) responsible for maintaining compliance with the NERC Reliability Standards requirements and the mandatory Western Electricity Coordinating Council (WECC) Regional Reliability Standards (NERC/WECC collectively, "Reliability Standards") requirements applicable to the functions for which BANC is registered. Diagram 1, below, shows the general framework of the ICP.

The goal of the ICP is to actively support a culture that continuously promotes and fosters a reliable and efficient Bulk Electric System (BES) by striving for operational excellence, including the incorporation of best-practices, principles, and processes that support Reliability Standards compliance. This ICPC establishes the framework for the plans, policies, procedures, systems, roles and responsibilities to monitor, assess, and ensure compliance with all applicable Reliability Standards and associated rules, orders, and regulations.

Compliance is accomplished through committed leadership, clear communication channels, training, individual performance and accountability, and a commitment to continuous improvement through monitoring activities, measuring, reporting, reviewing root causes, prevention, risk assessments, and responding to compliance and reliability issues.

Diagram 1: BANC ICP Framework



The ICP comprises six elements:

1. A Commission, comprised of an executive from each BANC Member (Member) agency, which is responsible for directing the program to meet the Reliability Standards applicable to BANC in its capacity as a NERC-registered Balancing Authority (BA) and Planning Coordinator (PC).

2. An independent Compliance Officer (CO), appointed by the Commission and responsible for reviewing compliance processes and plans, investigating potential violations of applicable Reliability Standards, self-reporting determined violations of those standards, directing the overall program goals, and providing periodic briefings and updates to the Commission, MCRC and BANC management.

3. A Member Compliance Review Committee (MCRC), comprised of representatives from each Member and a participant from the Western Area Power Administration -- Sierra Nevada Region (WASN), that is responsible for consulting with the CO with respect to compliance with applicable Reliability Standards.

4. The BANC Operator, who employs the SMEs responsible for meeting, maintaining, and providing the relevant documentation and technical expertise required to demonstrate compliance with all applicable Reliability Standards and who supports the compliance efforts of the CO and the MCRC.

5. BANC Counsel that provides legal support to the ICP.

6. A General Manager who implements the directives of the Commission and supports the ICP.

Section 2. Definitions and Terms

Unless otherwise defined herein, capitalized terms when used with initial capitalization, whether singular or plural, shall have the meaning set forth in the FERC-approved Glossary of Terms used in NERC Reliability Standards, the NERC Rules of Procedure, or the WECC/NERC Delegation Agreement, including the WECC Compliance Monitoring and Enforcement Program (CMEP).

2.1 "BA/PC Compliance List" shall mean the informational list of Reliability Standards applicable to BANC in its capacity as a NERC-registered Balancing Authority and Planning Coordinator maintained by Compliance Staff and made available to Members from time to time.

2.2 "Balancing Authority" or "BA" shall be defined by the prevailing FERC-approved definition of the term as published in the NERC Glossary of Terms.

2.3 "Balancing Authority Area" or "BAA" shall mean the collection of generation, transmission, and loads within the metered electrical boundaries of the Balancing Authority.

2.4 "Balancing Authority Operation Services Agreement" shall mean the Agreement between BANC and SMUD as the BANC Operator whereby SMUD shall perform specified services for BANC in accordance with the terms of that Agreement.

2.5 “BANC Operator” is the role that shall be filled by the entity contracted as operator of the BANC BAA.

2.6 “Bulk Electric System” shall be defined by the prevailing FERC-approved definition of the term as published in the NERC Glossary of Terms.

2.7 “Commission” shall mean the BANC Commission as established in the JPA, as that agreement may be amended from time to time.

2.8 “Compliance” shall mean the full performance of the duties and obligations necessary to comply with applicable Reliability Standards.

2.9 “Compliance Enforcement Authority” shall mean FERC, NERC, WECC, and any other agency, court, organization, or other entity or person duly authorized pursuant to law or regulation to: (a) audit or determine compliance with applicable Reliability Standards; or (b) impose, enforce, excuse, or rescind Penalties or otherwise take action binding on one or more Parties with respect to a finding of failure to comply with a Reliability Standard.

2.10 “Compliance Investigation Report” shall mean a report resulting from an Internal Compliance Investigation or other documentation as approved by the Compliance Officer for the purposes of documenting such an investigation, pursuant to Section 5.3 of this Charter.

2.11 “Compliance Monitoring and Enforcement Program Implementation Plan” or “CMEP-IP” shall mean the program used by WECC to monitor, assess, and enforce compliance with Reliability Standards for entities within its footprint.

2.12 “Compliance Officer” or “CO” shall mean the individual appointed by the Commission to establish and direct the implementation of the BANC Internal Compliance Program approved by the Commission.

2.13 “Compliance Staff” shall mean a compliance team, consisting of one or more members, led by the CO.

2.14 “FERC” shall mean the Federal Energy Regulatory Commission.

2.15 “General Manager” shall have the meaning described in Section 3.8 of this Charter.

2.16 “Internal Compliance Investigation” shall have the meaning described in Section 5.3 of this Charter.

2.17 “Internal Compliance Program” or “ICP” shall mean both the policy-level and program-level component documents and all implementing actions that are done in support of Compliance.

2.18 “Internal Compliance Program Charter” or “ICPC” shall mean the policy-level component document of the BANC Internal Compliance Program, approved by the Commission and implemented by the Compliance Officer to ensure Compliance. The BANC ICPC is the governing document for the BANC ICP, and the MCRC is a functional component of that program. MCRC roles and responsibilities are defined in the MCRC Charter.

2.19 "Internal Controls" shall have the same meaning as used in SMUD's Internal Controls Evaluation Program, as this definition may be amended from time to time.

2.20 "Joint Powers Agreement" or "JPA" shall mean the Second Amended Joint Exercise of Powers Agreement, effective July 1, 2013, as such agreement may be amended from time to time under its provisions.

2.21 "Member" shall mean a party to the JPA, as that agreement may be amended from time to time.

2.22 "NERC" shall mean the North American Electric Reliability Corporation.

2.23 "PC Participant" shall mean a Member signatory to the PC Participation Agreement.

2.24 "PC Participation Agreement" shall mean the agreement between BANC and certain Members who desire to have BANC serve as their PC.

2.25 "PC Services Agreement" shall mean the agreement between BANC and SMUD whereby SMUD has agreed to perform specified PC services for BANC in accordance with the terms of that agreement.

2.26 "PC Services Provider" shall mean the entity providing PC Services to BANC. SMUD is the contracted PC Services Provider pursuant to the terms set forth in the PC Services Agreement.

2.27 "Planning Coordinator" or "PC" shall have the same meaning as used in the NERC Glossary of Terms, as this definition may be amended from time to time.

2.28 "Reliability Standards" shall mean those NERC Reliability Standards and WECC Regional Reliability Standards that have been approved by FERC under Section 215 of the Federal Power Act and WECC applicable Regional Criterion referenced in FERC-approved Reliability Standards.

2.29 "Representative" shall mean a member of MCRC.

2.30 "Subject Matter Expert" or 'SME" shall mean those responsible for maintaining compliance with applicable Reliability Standards.

2.31 "WECC" shall mean the Western Electricity Coordinating Council or its successor.

Section 3. BANC Internal Compliance Program Structure

3.1 BANC

BANC is registered for the following NERC Functions:

- BA (Balancing Authority)
- PC (Planning Coordinator)

BANC Members and other relevant NERC functional registrations within the BANC BAA footprint are provided in Appendix B.

3.2 Commission

The Commission collaborates with and directs the CO as issues regarding BANC's system reliability policies, strategies, and priorities are identified and addressed. The Commission shall ensure that necessary resources are provided to the BANC Operator to support compliance activities and the ICP. The Commission shall facilitate communication, the exchange of information, and coordination among Members on issues that impact electric reliability. It shall meet on compliance matters, as required by events and conditions. These meetings may be held in conjunction with regular meetings of the Commission.

3.3 Compliance Officer

The Compliance Officer reports directly to the Commission. The CO shall have authorized executive responsibility for the approval of all compliance certifications and submittals that are required of BANC. The CO shall ensure that BANC's policies, decisions, and documentation regarding Reliability Standards are appropriate and effective. The CO, in coordination with Compliance Staff and the MCRC, interacts with the SMEs to ensure that the elements of the ICP are being met. The CO shall conduct independent reviews of processes and documentation prepared to demonstrate compliance. Specifically, the CO shall:

3.3.1 Assess the BANC Operator's performance with respect to its adherence to applicable Reliability Standards.

3.3.2 Lead Internal Compliance Investigations and determine compliance with applicable Reliability Standards.

3.3.3 Ensure that the ICP is in place and effective in meeting BANC's reliability obligations.

3.3.4 Approve all official compliance documents and certifications on behalf of BANC.

3.3.5 Periodically update the Commission on BANC's compliance efforts.

3.3.6. Ensure the General Manager and BANC Counsel are updated on an "as-needed" basis regarding compliance events or other matters impacting ICP objectives.

3.3.7 Request additional resources from the Commission, when necessary, to meet compliance obligations.

3.3.8 Monitor compliance performance data from the BANC Operator and recommend appropriate actions or mitigation procedures.

3.3.9 Ensure effective processes are in place to develop accurate and timely responses for compliance-related requests from a Compliance Enforcement Authority.

3.3.10 Act as an independent point of contact for the BANC Operator or Members to report potential violations of applicable Reliability Standards.

3.3.11 Develop and maintain ICP documents that outline more detailed internal reliability compliance processes.

3.3.12 Serve as Chair of the MCRC.

3.4 Member Compliance Review Committee

Under the direction of the CO, the Member Compliance Review Committee (MCRC) provides input with respect to the following: (1) the development of, and ongoing improvements to, the ICP; (2) ongoing updates to the BA/PC Compliance List; (3) ongoing compliance matters regarding BANC in its capacity as a BA and a PC; and (4) the review of notices or actions directed to BANC from a Compliance Enforcement Authority. A more detailed description of the roles and responsibilities of the MCRC is set forth in the "Member Compliance Review Committee Charter," which is provided as Appendix A to this ICPC.

3.5 BANC Operator

The BANC Operator is responsible for managing and generating the critical information to meet compliance requirements and respond to other regulatory obligations at the direction of the CO or the MCRC. The BANC Operator shall employ SMEs with the expertise to meet or exceed that which is necessary to ensure Compliance. BANC Operator SMEs shall provide documentation that demonstrates compliance with applicable Reliability Standards in accordance with specified timelines. In particular, the BANC Operator shall:

3.5.1 Promote the exchange of information through development of good practices and effective work processes that assist in achieving safe, reliable, and efficient operation.

3.5.2 Recognize the importance of improving or revising existing practices when necessary.

3.5.3 Report any potential violations to the CO for further investigation and cooperate with the CO during any such investigation.

3.5.4 Identify any resource issues associated with compliance with applicable Reliability Standards and work with the CO and MCRC to promptly address those concerns to ensure Compliance.

3.5.5 Upon request, provide a position, and, if further requested, propose language to the MCRC with respect to applicable Reliability Standards under development.

3.6 BANC Planning Coordinator

BANC is the registered PC for its Members who have executed the PC Participation Agreement. As the registered PC for PC Participants, BANC is responsible for managing and generating the critical information to meet compliance requirements and respond to other regulatory obligations at the direction of the CO or the MCRC. To support this obligation, BANC has contracted with a PC Services Provider. The PC Services Provider is required to employ SMEs with the expertise to meet or exceed that which is necessary to ensure Compliance with all applicable Reliability Standards. Specifically, the PC Services Provider shall:

3.6.1 Promote the exchange of information through development of good practices and effective work processes that assist in achieving safe, reliable, and efficient operation.

3.6.2 Recognize the importance of improving or revising existing practices when necessary.

3.6.3 Report any potential violations to the CO for further investigation and cooperate with the CO during any such investigation.

3.6.4 Identify any resource issues associated with compliance with applicable Reliability Standards and work with the CO and MCRC to promptly address those concerns to ensure Compliance.

3.6.5 Upon request, provide a position, and, if further requested, propose language to the MCRC with respect to applicable Reliability Standards under development.

3.7 BANC Counsel

BANC Counsel shall advise the Commission, Compliance Officer, and MCRC on NERC reliability compliance and enforcement matters, regulatory proceedings before FERC involving the development of NERC standards, and all other issues involving NERC Reliability Standards and compliance as they relate to BANC. BANC Counsel shall assist with Internal Compliance Investigations and determinations. BANC Counsel shall coordinate with the Commission, MCRC, BANC Operator, BANC Planning Coordinator, and General Manager to develop BANC comments on Reliability Standards before FERC, if so requested.

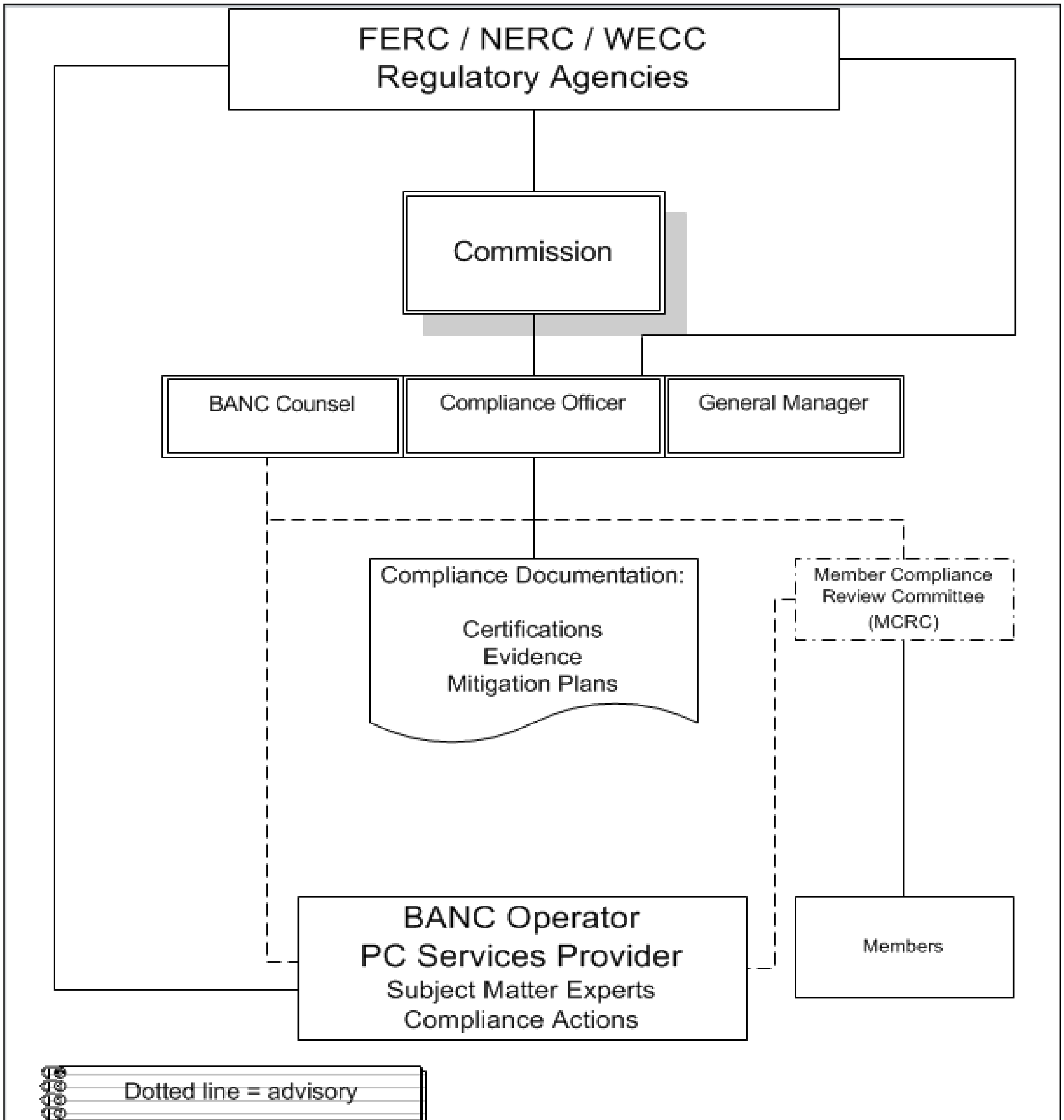
3.8 General Manager

The General Manager is the chief executive officer of BANC. The General Manager is responsible for implementing the directives of the Commission, providing executive support for the ICP and supporting a culture of compliance within the organization.

Section 4. Compliance Reporting Structure

The ICP is organized to ensure that appropriate and effective processes, policies, and practices related to Balancing Authority and Planning Coordinator reliability are established and executed. It is structured to keep the execution of work as close to the primary implementers and experts as possible. The relationship of these components is illustrated in Diagram 2.

Diagram 2: Illustration of BANC Internal Compliance Program Relationships



Section 5. Elements of BANC Internal Compliance Program

The ICP promotes coordination, communication, efficiency, and effectiveness to ensure Compliance.

5.1 Operational Independence

The CO, in coordination with the MCRC and Compliance Staff, implements the ICP. The CO, Compliance Staff, and the MCRC do not manage or perform line functions or make operational decisions. The BANC Operator and PC Services Provider perform line functions and operational actions in accordance with the Balancing Authority Operation Services Agreement. The PC Services Provider performs PC functions in accordance with the PC Services Agreement. The MCRC reports directly to the CO, who in turn reports directly to the Commission.

5.2 Compliance Monitoring and Training

The CO, in coordination with the MCRC and Compliance Staff, shall proactively monitor compliance.

5.2.1 Continuous Self-Assessment and Correction

The CO, in coordination with the MCRC and Compliance Staff, may direct periodic assessments of BANC compliance efforts, generally with an emphasis on those Reliability Standards that pose the greatest risk to the reliability of the BES and BANC BAA. These assessment(s) aim to identify and address reliability risks that may lead to potential violation(s). The CO may share the results of these assessments with the General Manager and with the Commission in closed session, as directed by BANC Counsel. An example of continuous review may include ensuring that the BANC Operator and/or PC Services Provider completes and documents a rigorous analysis of potentially compliance-related events. The need for such assessment shall be determined by the CO; however, such assessment(s) may be also requested by the Commission.

5.2.2 Compliance Communication and Training

The CO, in coordination with the MCRC, shall disseminate to the BANC Operator and PC Services Provider "lessons learned" and other issuances related to BANC's compliance obligations. The BANC Operator and Planning Coordinator SMEs and staff shall receive annual compliance training, which shall include the process for self-reporting potential violations. The BANC Operator and Planning Coordinator SMEs shall have access to an internal compliance website with a link available to any SME or staff member to report any potential violation of a Reliability Standard.

The CO, in coordination with the MCRC, shall review the need for a meeting no less frequently than once per quarter. Meetings may be held either in person or via teleconference.

During any such meeting, the MCRC shall receive an update on BANC compliance activities. The CO shall keep the MCRC apprised of the status of any potential violations.

The CO shall regularly update the Commission on BANC compliance activities. Such updates shall be held in closed session to the extent that the discussion requires disclosure of critical infrastructure information, personnel matters or information regarding pending or threatened litigation. The determination as to whether all or a portion of the update on other compliance activities should be held in closed session shall be determined by BANC Counsel.

5.3 Internal Compliance Investigations

Upon learning of any circumstance of potential non-compliance, the CO shall first confirm with the BANC Operator and/or PC Services Provider that any ongoing possible reliability risks have been removed and will then commence an investigation to determine whether a potential violation of one or more applicable Reliability Standards occurred. The CO may consult with BANC Counsel and notify the General Manager and the MCRC regarding items reviewed at any point during the investigation. Further, the CO may seek review and recommendations from the MCRC on any matter undergoing an Internal Compliance Investigation. The role of the MCRC regarding an Internal Compliance Investigation is set forth in more detail in Section 6 of the MCRC Charter.

Upon conclusion of the investigation, if the CO believes that a potential violation of an applicable Reliability Standard occurred, the CO shall file either a Self-Report or a Self-Log[1] with a Compliance Enforcement Authority. If the CO concludes that no potential violation occurred, the CO shall close the matter and maintain relevant documentation, including a Compliance Investigation Report, in BANC's compliance files. Further, the CO may recommend that the BANC Operator or PC Services Provider conduct a review and/or revision of related processes and procedures to ensure that full compliance is reinforced.

5.4 Process for Handling Potential Non-Compliance

The CO may be notified of a potential violation by any compliance monitoring method utilized by a Compliance Enforcement Authority including: (1) Audit; (2) Self-Certification; (3) Spot Checks; (4) Periodic Data Submittals; (5) Exception Reporting; (6) Compliance Violation Investigations; (7) Self-Report/Self-Log; and (8) Complaint.

Upon receipt of a notice of potential violation and/or Compliance Exception[2] issued by a Compliance Enforcement Authority, the CO shall notify BANC Counsel and the General Manager. The CO shall ensure that such notice is also provided to the BANC Operator and/or PC Services Provider and the MCRC. The CO shall coordinate with BANC Counsel, the

---

[1] Following the 2016 NERC Compliance Audit, BANC was awarded self-logging privileges for minor issues that pose minimal risk to the reliability of the BES. See §4.5A of the NERC CMEP, Appendix 4C to the Rules of Procedure.
[2] The Compliance Exception process is set forth in §4A.1 of the NERC CMEP, Appendix 4C to the Rules of Procedure.

General Manager, the MCRC and the Commission in responding to any notices of potential violation.

The CO shall follow and adhere to all of the processes described in the CMEP-IP regarding the processing of violations.[3]

5.5 Internal Controls Evaluations Program

The CO shall oversee the implementation of an Internal Controls Evaluation (ICE) Program that describes how BANC identifies, documents, and evaluates internal controls. The ICE Program incorporates internal controls guidance provided by NERC and WECC and is consistent with established industry best practices. ICE Program activities support BANC's participation in the internal controls review process that WECC incorporates as a part of its CMEP activities.

The ICE Program integrates with other Internal Compliance Program elements related to BANC's reliability, security, and compliance objectives. The identification and documentation of internal controls primarily focus on areas that are determined to have higher levels of inherent risk. The ICE Program includes a transparent and repeatable process to evaluate the effectiveness of internal controls, resulting in reports that convey control effectiveness, residual risk, areas of strength, and recommendations for consideration. These reports are utilized as a part of the overall ICP to facilitate a better understanding of residual risk associated with applicable Reliability Standards. Updates regarding ICE Program activities are communicated in accordance with Section 5.2.2 of this charter.

5.6 Review of BANC Internal Compliance Program and Internal Compliance Program Charter

The CO shall conduct an annual audit of the ICP. The CO may request that such an audit be performed by a third-party. A copy of the final annual ICP audit report shall be provided to the Commission. The MCRC shall have an opportunity to review the ICP audit report prior to the report going to the Commission.

Additionally, at any time, the CO, the Commission, any MCRC Representative or BANC Counsel may propose any appropriate or necessary changes to ensure the effectiveness of the ICP or the accuracy of this ICPC. Such changes may include incorporating elements proposed by FERC in its policy statements, rules, or orders, or any other guidance proposed by a Compliance Enforcement Authority. The CO shall document the date of any review, as well as any changes made to the ICP or this ICPC. Changes to the ICPC are reflected through a change to its version number.

[3] https://www.nerc.com/pa/comp/Pages/Reliability-Assurance-Initiative.aspx
https://www.wecc.org/program-areas/compliance/compliance-united-states

Section 6. Review and Approval

BANC Internal Compliance Program Charter
Prepared by: _______________________________ Date ______________ James Leigh-Kendall BANC Compliance Officer *Legal Concurrence:* _______________________________ Date ______________ C. Anthony Braun BANC General Counsel *General Manager Concurrence:* _______________________________ Date ______________ James R. Shetler BANC General Manager *Commission Approval:* _______________________________ Date ______________ BANC Chairperson BANC Commission

Section 7. Revision History

BANC Internal Compliance Program Charter			
Version	**Issue Date**	**Approved**	**Remarks**
1.0	March 18, 2011	March 4, 2011	Approved by Commission as to Substance
2.0	May 16, 2012	May 23, 2012	Approved by Commission as to Substance
3.0	May 23, 2014	May 28, 2014	Approved by Commission as to Substance
4.0	April 29, 2016	June 22, 2016	Approved by Commission as to Substance
5.0	July 31, 2017	August 23, 2017	Approved by Commission as to Substance
6.0	March 21, 2019	March 27, 2019	Approved by Commission as to Substance
7.0	March 17, 2022	March 23, 2022	Approved by Commission as to Substance
8.0	August 18, 2023	September 27, 2023	Approved by Commission as to Substance
9.0	November XX, 2024	November 20, 2024	Approved by Commission as to Substance

Appendix A

Member Compliance Review Committee Charter

Appendix B

General Structure and Relevant NERC Functional Registrations within the BANC Balancing Authority Area Footprint

Figure 1: General BANC BA/PC Structure

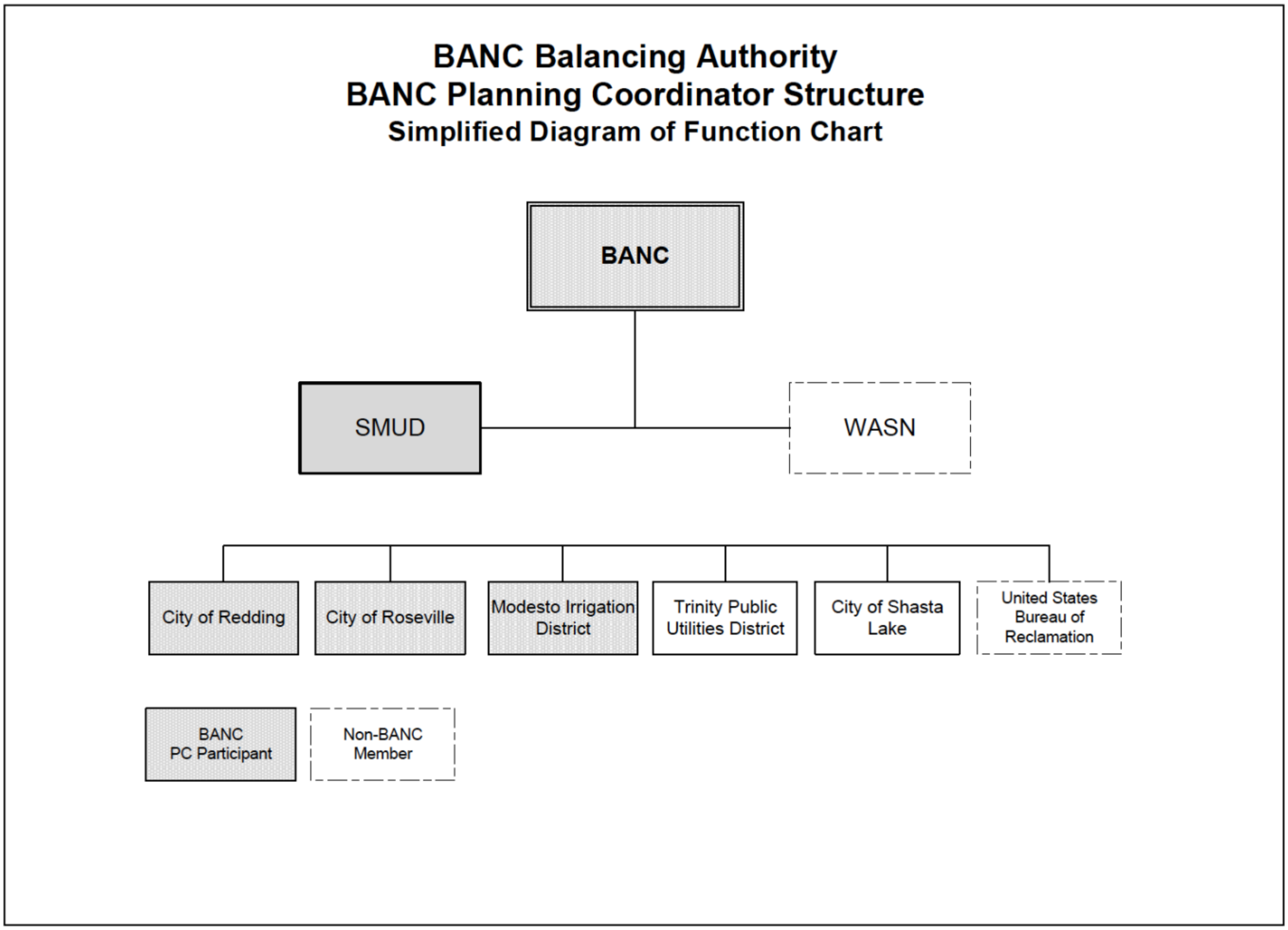


Figure 2: Relevant NERC Functional Registrations within the BANC BA Area Footprint

	BANC	**City of Roseville**	**City of Shasta Lake**	**MID**	**REU**	**SMUD**	**TPUD**	**WASN**	**US BoR**
BANC Member	X	X	X	X	X	X	X		
BANC PC Participant	X	X		X	X	X			
Western SBA Member		X	X	X	X		X		X
Functional Registration									
BA	X								
DP		X		X	X	X			
GO				X	X	X			X
GOP				X	X	X			X
PA/PC	X							X	
RP		X		X	X	X		X	
TO				X	X	X		X	X
TOP				X	X	X		X	
TP				X	X	X		X	
TSP						X		X	

(**Note:** Western Area Power Administration -- Sierra Nevada Region (WASN) operates under the BANC BA as a sub-Balancing Authority (SBA), and many utilities operate under the WASN SBA. However, not all utilities are members of BANC. The table above shows the utilities, their operational relationship(s), BANC membership and functional registration(s).

Balancing Authority of Northern California

Appendix A to the BANC Internal Compliance Program Charter

Member Compliance Review Committee Charter

Version 9.0

Member Compliance Review Committee Charter

TABLE OF CONTENTS

Introduction

Pursuant to Section 6.2 of the Balancing Authority Operation Services Agreement (BOSA) between the Balancing Authority of Northern California (BANC) and the Sacramento Municipal Utility District (SMUD), the BANC Commission authorized the Compliance Officer (CO) to form the Member Compliance Review Committee (MCRC), which serves in an advisory role to the CO. This BANC MCRC Charter (Charter) sets forth the general roles and responsibilities of the MCRC, consistent with this authorization.

General Statement of Purpose of MCRC

The MCRC will consult with the BANC CO with respect to: (1) the development and ongoing improvements to the BANC Internal Compliance Program (ICP); (2) ongoing updates to the list of Reliability Standards applicable to the BANC in its capacity as a NERC-registered Balancing Authority (BA) and Planning Coordinator (PC) (BA/PC Compliance List); (3) ongoing compliance matters regarding the BANC BA and PC functions; and (4) the review of notices or actions directed to the BANC from the Compliance Enforcement Authority.

Section 1. Definitions and Terms

Unless otherwise defined herein, capitalized terms when used with initial capitalization, whether singular or plural, shall have the meaning set forth in the FERC-approved Glossary of Terms Used in NERC Reliability Standards, the NERC Functional Model, the WECC/NERC Delegation Agreement, including the WECC Compliance Monitoring and Enforcement Program (CMEP), or the BANC ICPC.

1.1 "BANC Member Agreement" or "Member Agreement" shall mean the Agreement between BANC and its participating members that sets forth the roles, obligations, and responsibilities of the Parties to one another with regard to the operation of the Balancing Authority.

1.2 "Confidential Information" shall mean: (a) all written materials marked "Confidential," "Proprietary," or with words of similar import provided to the Representative by another Representative, the CO, the BANC Operator, the PC Services Provider, or a Member; and (b) all observations of equipment (including computer screens) and oral disclosures related to a Representative's, the BANC Operator's, the PC Services Provider's, or Member's systems, operations, or activities that are indicated as such at the time of observation or disclosure (or identified as "confidential" or "proprietary" in a letter sent to the Representative, the MCRC or the CO no later than five (5) calendar days after the disclosure), respectively. Confidential Information includes portions of documents, records, and other material forms or representations that the Representative(s), the CO, the BANC Operator, the PC Services Provider, or Member(s) may create, including but not limited to, handwritten notes or summaries that contain or are derived from such Confidential Information.

1.3 "Identified Member" shall mean any entity that is a member of the MCRC (inclusive of the Western Area Power Administration - Sierra Nevada Region or "WASN") and identified in an incident subject to an Internal Compliance Investigation.

1.4 "Segment" shall have the meaning and include the qualifications set forth in Appendix 3D [Registered Ballot Body Criteria — Development of the Registered Ballot Body][1] of the NERC Rules of Procedure, as that procedure may be periodically updated by NERC and approved by FERC.

Section 2. Functions

2.1 General Forum. The MCRC provides a general forum for members to discuss and address issues relating to applicable Reliability Standards compliance matters. The MCRC assists the CO in the implementation of the ICP, the development of BANC's positions on proposed Reliability Standards, and all compliance regulation matters affecting BANC as directed by the CO.

2.2 Consultation. The MCRC consults with the CO with respect to:

2.2.1 Development and Ongoing Improvements to the ICP. Upon request by the CO, the MCRC will review specific elements of the ICP and provide its recommendations to the CO.

2.2.2 Development and Ongoing Improvements to the ICPC. Upon request by the CO, the MCRC will conduct periodic reviews of the ICPC and provide its recommendations to the CO. The MCRC will have the opportunity to review and make recommendations on all proposed changes to the ICPC.

2.2.3 Ongoing Updates to the BA/PC Compliance List. At the direction of the CO, an updated list of current and near-term future enforceable applicable Reliability Standards shall be provided to MCRC members for their review, use, and reference.

2.2.4 Ongoing BANC Compliance Matters. The CO will apprise the MCRC regarding any compliance matters directed towards the BA and/or PC, and the MCRC will provide the CO with its input on such matters in accordance with Section 6 of this Charter.

2.2.5 Review of Notices or Actions Directed to BANC. At the direction of the CO, the MCRC will review any notices or actions directed to BANC from a Compliance Enforcement Authority, including actions resulting from the CMEP-IP.

Section 3. Membership

3.1 Selection. Each Member shall have one Representative serve on the MCRC. Each Member may select one or more alternate Representatives meeting the requirements of Section 3.2 to serve in the primary Representative's absence.

3.1.1 WASN may have a non-voting Representative and alternate(s).

3.2 Qualifications. The MCRC is a technical committee and requires competency to review materials prepared by SMEs regarding electric utility BA operations, PC activities, and/or

[1] https://www.nerc.com/AboutNERC/RulesOfProcedure/ROP%20App%203D%20eff%2020220825%20clean.pdf

Reliability Standards compliance matters. The CO may interview or seek additional information regarding the Representatives put forward by the Members. In the event that the CO believes that a particular Representative advanced by a Member is unqualified and the Member has a more qualified candidate to be the Member Representative, the CO shall raise (either verbally or in writing) his or her concerns directly with the appropriate member of the Commission.

3.3 Expectations of Representatives. Each Representative is expected to:

3.3.1 Be or become competent to review materials prepared by SMEs for the MCRC's use in preparing or reviewing compliance-related responses.

3.3.2 Attend and/or participate regularly in MCRC meetings and/or teleconferences.

3.3.3 Provide input that looks beyond the individual Member's interests and attempts to advocate and advise in the best interest of BANC.

3.3.4 Complete any assignment or review requested by the CO in a timely and professional manner.

3.3.5 Remain apprised of developments regarding applicable Reliability Standards as those developments are brought to the attention of the MCRC.

3.4 Expectations of the Compliance Officer. The CO shall also serve as the official contact to and from MCRC Representatives for the purpose of gathering and disseminating BANC compliance-related information. With respect to the MCRC, the CO is expected to:

3.4.1 Attend and/or participate in MCRC meetings and/or teleconferences.

3.4.2 Consult with MCRC Representatives on all required compliance-related matters as described in Section 6.2 of the BOSA.

3.4.3 Make recommendations that are in the best interest of BANC. In making these recommendations, the CO shall consider individual Members' concerns and interests after consulting with the MCRC.

3.4.4 Investigate and report to WECC and to the MCRC any potential violation of a Reliability Standard as required in Section 7.3 of the Member Agreement.

3.4.5 Convene a meeting of the MCRC upon receipt of a written notice of an alleged violation as required in Section 7.4 of the Member Agreement.

3.4.6 Notify the MCRC of any scheduled compliance audit as required in Section 7.5 of the Member Agreement.

3.4.7 Develop and maintain a BA/PC Compliance List in consultation with the MCRC as required in Section 6.3 of the BOSA.[2]

[2] Section 6.3 of the BOSA specifically references the "BA Compliance List" and not the "BA/PC Compliance List." This has been changed to address the expanded role of BANC as a registered Planning Coordinator. The authority

3.5 Term. Each Representative serves at the will of the appointing Member, or, in the case of WASN, at the discretion of its internal selection process.

Section 4. Meetings

4.1 Formal Actions. The MCRC serves in a consultative role to the CO. From time to time, the MCRC may desire, or be asked by the CO, to adopt a formal position or decision while serving in this capacity. Any formal action taken by the MCRC shall require the affirmative vote of a majority of the Member Representatives (thus, the determination of a majority does not include the CO, the BANC Operator representative(s), or the PC Services Provider representative(s)). Positions and/or decisions from the MCRC adopted pursuant to this Section 4.1 are not binding upon the CO; however, should the CO take action contrary to an adopted position and/or decision of the MCRC, the CO will follow the process described in Section 6.3.

4.2 Voting. Each Member Representative shall have one vote.

4.3 WASN. WASN may serve as a non-voting Representative at all MCRC meetings. Should WASN become a voting member on the Commission, its Representative will become eligible to vote on MCRC matters.

4.4 BANC Counsel will provide legal support to the CO and the MCRC.

4.5 The BANC Operator and/or the PC Services Provider shall attend meetings and provide updates as to relevant performance when requested by the CO.

4.6. The General Manager will provide executive support to the CO and the MCRC.

4.7 Teleconferencing may be used for all purposes in connection with any meeting. Voting Representatives attending a meeting by teleconference shall be included in the calculation of a quorum. All votes taken during a teleconferenced meeting shall be by roll call.

Section 5. Officers

5.1 Chairperson. The CO shall be the Chairperson of MCRC meetings.

5.2 Vice Chair. The Representatives may select from among themselves a Vice Chair who shall work to direct any work product or other tasks assigned to Representatives. The Vice Chair shall also be responsible for communicating to the CO the MCRC's adopted formal position on a newly proposed Reliability Standard and/or modifications to an existing Reliability Standard, as set forth in Section 6.4 below.

5.3 Secretary. The Representatives may select a Secretary to record minutes of MCRC meetings, provide meeting notices, and address other administrative matters as directed by the

---

of the CO to make such a change resides in this same section, which provides that : "[t]he Compliance Officer, in consultation with the MCRC, shall update the BA Compliance List from time to time to reflect changes in Reliability Standards applicable to a BA, *or for any other reason deemed appropriate by the Compliance Officer*" (emphasis added).

Chairperson. In the absence of the specific selection of a Secretary, the Chairperson will ensure that meeting minutes, notices and other administrative matters required to support the MCRC are provided.

5.4 Term. Except for the Chairperson, Officers shall serve at the pleasure of the MCRC.

Section 6. Reports, Recommendations and Segment Voting

6.1 Reports. At the direction of the CO, the MCRC will develop reports from time to time regarding specific compliance matters. Except for any reports provided directly to the Commission pursuant to Section 8, all reports are directed to the CO and are to be treated as Confidential Information in accordance with Section 10. The BANC Operator and/or PC Services Provider shall provide assistance to the MCRC in the development of any reports as requested by the CO.

6.2 Recommendations of MCRC to the Compliance Officer.

6.2.1 General Recommendations of MCRC. The CO will submit a self-log or file a self-report with WECC for any violation of a NERC Reliability Standard. During the investigation of events or other reviews, except as provided in Section 6.2.1.1, the CO may seek a recommendation from the MCRC regarding a specific compliance matter, including, but not limited to, whether to submit a self-log or self-report to a Compliance Enforcement Authority the potential violation of an applicable Reliability Standard. Such matters may include MCRC review of draft Compliance Investigation Reports, subject to the process further described in Section 6.2.1.1, resulting from an Internal Compliance Investigation by the CO. Recommendations may require voting in accordance with Section 4 of this Charter, and such recommendations may be given verbally or, if requested by the CO, in writing. Recommendations are not binding on the CO; however, they should be afforded proper deference.

6.2.1.1 Identified Member(s) Initial Review of Draft Compliance Investigation Report. An Identified Member or Identified Members shall be afforded an opportunity to review and comment on the draft Compliance Investigation Report prior to its distribution to the full MCRC in accordance with the following:

6.2.1.1.1 Identified Member(s) shall be afforded an opportunity to review the *initial* draft Compliance Investigation Report prior to its distribution to the full MCRC.

6.2.1.1.2 A reasonable time for review shall be provided to the Identified Member(s) to review the *initial* draft Compliance Investigation Report.

6.2.1.1.3 The CO shall address the Identified Member's (or Members') comments and create a *revised* draft for review by the entire MCRC.

6.2.1.1.4 The CO shall distribute the *revised* draft Compliance Investigation Report and Identified Member comments to the entire MCRC.

6.2.1.1.5 A final decision as to the content of the Report, although subject to Identified Member's (or Members') review, resides with the CO.

6.2.2 All exchanges of Compliance Investigation Reports under this Section 6.2 shall be through BANC Counsel.

6.3 CO Actions Contrary to the Position or Decision of the MCRC. If the CO takes any action contrary to a position and/or decision of the MCRC adopted pursuant to Section 4.1, the CO shall provide a report to the Commission providing the details of the discussions with the MCRC on the subject, the details of the CO's action, and rationale for such action. A copy of such report shall be provided to the MCRC Representatives.

6.4 MCRC Segment Voting in NERC Reliability Standard Development Process. BANC will join the appropriate NERC Registered Ballot Body and self-select the segment(s) for which BANC qualifies. At the direction of the CO, the MCRC may be required to determine its position specific to a newly proposed Reliability Standard and/or modifications to an existing Reliability Standard. The MCRC's formal position shall be adopted by consensus, or, if requested by a Representative, a vote of the Representatives pursuant to Section 4.1. It shall be the responsibility of the CO to ensure BANC's position, as communicated to the CO by the MCRC, is properly registered with NERC.

Section 7. Interaction with BANC Operator and PC Services Provider

7.1 Advisory Role. The BANC Operator and PC Services Provider serve in an advisory role to review or make recommendations on materials prepared by the MCRC for proposed compliance actions. The BANC Operator's and PC Services Provider's SMEs are reasonably expected to develop and expand the knowledge base of the MCRC by maintaining and providing the base documentation and technical expertise required to demonstrate compliance and respond to other regulatory obligations at the direction of the CO. This may further include offering recommendations upon request regarding various matters, including, but not limited to, the MCRC's responses to the CMEP-IP, the adoption of a position as to a revision to an existing Reliability Standard, the adoption of a new Reliability Standard, or modifications to the BANC ICP.

7.2 MCRC Contact with BANC Operator and PC Services Provider. It is expected that the primary interaction between Representatives and the BANC Operator and PC Services Provider will occur at MCRC meetings.[3] Questions or concerns from Representatives outside of an approved process or inquiry shall be directed to the CO. In the case of inquiries providing evidence or in reviewing or developing reports agreed upon by the CO and the MCRC, the

[3] The PC Services Provider also interacts with participating BANC PC member representatives through a separate working committee to address their respective functional obligations.

BANC Operator and/or PC Services Provider shall use reasonable efforts to respond to the CO in a timely manner.

Section 8. Interaction with Commission

Unless specifically requested by the CO or the Commission, the MCRC shall not provide direct reports to the Commission. If so requested, the Vice Chair or his or her designee shall make such a report. However, an individual Representative may consult with his or her internal legal counsel or Commission member.

Section 9. External Communications

Representatives shall abide and are bound by all of the Confidentiality provisions of this Charter and shall not provide or disseminate any Confidential Information obtained through participation on the MCRC. Further, Representatives shall not initiate or respond to requests for information from third parties, including but not limited to a Compliance Enforcement Authority or media outlets unless otherwise directed by the Commission or the CO.

Section 10. Confidentiality

10.1 Confidentiality. Representatives recognize that for the purposes of performing their role on the MCRC, which may include advising the CO as to how BANC should respond to any report or notice of potential violation of a Reliability Standard, Representatives may receive information from Members, the BANC Operator, the PC Services Provider, and/or the CO that has been marked as Confidential Information. Representatives agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, unless directed, in writing, by the CO or the Commission. Any requests for the disclosure of Confidential Information made to the MCRC or an individual Representative shall be directed to the CO. Any questions relating to Confidentiality as applied to the MCRC shall be directed to BANC Counsel. Consultation with the Representative's internal counsel or Commission member is not a violation of Confidentiality.

10.2 Survival of Obligation. Obligations regarding Confidentiality shall continue after a Representative ends his or her role on the MCRC.

Section 11. Revision History

BANC MCRC Charter	
Version	**Issue Date**
1.0	February 21, 2011
2.0	October 27, 2011
3.0	April 25, 2012
4.0	May 23, 2014
5.0	July 31, 2017
6.0	March 7, 2019
7.0	March 17, 2022
8.0	September 27, 2023
9.0	November XX, 2024