Agenda
Real Time Operating Subcommittee

February 4, 2025 | 12:00 p.m. – 5:00 p.m. Eastern | Open Session
February 5, 2025 | 8:00 a.m. – 12:00 p.m. Eastern | Closed Session

Florida Reliability Coordinating Council
3001 North Rocky Point Drive East, Suite 410
Tampa, FL 33607

WebEx
Dial-in Number: + 1-415-655-0002 US Toll (Canadian Toll) + 1-416-915-8942
Meeting Number Access Code: 2309 023 5271 | Security Code: aF4JEywcB22

Introductions and Chair's Remarks – Chair Christopher Wakefield, Sothern Company

NERC Antitrust Compliance Guidelines, Public Announcement, and Participant Conduct Policy

Agenda

1. **Administrative *(5 minutes)***
   a. Announcement of Quorum – Tony Burt, NERC
      i. Parliamentary Procedures*
      ii. Balancing Authority-to-Reliability Coordinator Mapping*
         (1) Balancing Authority, BNBA (FirstLight Energy), added to the SPP West RC
   b. Future Meetings
      i. 2024 Meeting dates
         (1) May 14, 2025 | Virtual
         (2) September 3, 2025 | Virtual
         (3) November 12-13, 2025 | TBD
         (4) February 4-5, 2026 | Florida Power & Light | Miami, FL
         (5) May 13, 2026 | Virtual
         (6) September 2, 2026 | Virtual
         (7) November 18-19, 2026 | TBD
2. **Meeting Notes* (Approve) – Chair Wakefield *(5 minutes)***
   a. Notes of November, 2024 Real Time Operating Subcommittee Meeting (*Extranet site*)
3. **Review RTOS Work Plan* – Chair Wakefield *(10 minutes)***
   a. Review 2025 RTOS Work Plan

i. IROL Activity Team Update: *ERO Enterprise Joint IROL Activity Report* – Jon Sawyer

ii. IROL Report Recommendations – Jon Sawyer

iii. RTOS Scope Update – Paul Davis

4. RTOS Executive Committee Membership Updates – Chair Wakefield

a. RC West

b. ERCOT

c. Hydro Quebec?

5. Reliability Plans* – Chair Wakefield *(10 minutes)*

a. New or Revised Reliability Plans for Endorsement

i. SPP – Derek Hawkins

ii. MISO – John Harmon

6. Reliability and Security Technical Committee (RSTC) Update* – Steve Crutchfield, NERC

a. RSTC 2025 Work Plan Update*

7. SAFNR Update – Darrell Moore; Mike Legatt, Resilient Grid

Break *(15 minutes)*

8. Resources Subcommittee (RS) Update to RTOS – Chair Greg Park, WECC *(60 minutes)*

a. Review of any abnormal frequency events identified by the RS Frequency Subcommittee

b. Report out on Inadvertent Accumulation

9. Synchronized Measurement Working Group (SMWG) Update – Chair Clifton Black, Southern Company *(10 minutes)*

a. Review of any new or updated oscillation event analysis

10. Time Monitor Change – Chair Wakefield *(5 minutes)*

a. VACAR – February 1, 2025 through January 31, 2026

11. GMD Monitor Change *(5 minutes)*

a. Eastern Interconnection

i. VACAR – February 1, 2025 through January 31, 2026

b. Western Interconnection

i. BCRC – February 1, 2025 through January 31, 2026

12. Interconnection Frequency Monitoring *(15 minutes)*

a. Frequency Monitor Reports and Frequency Excursions – All

i. Eastern – Terry Williams

ii. ERCOT – Jimmy Hartmann

iii. Western – Scott Rowley

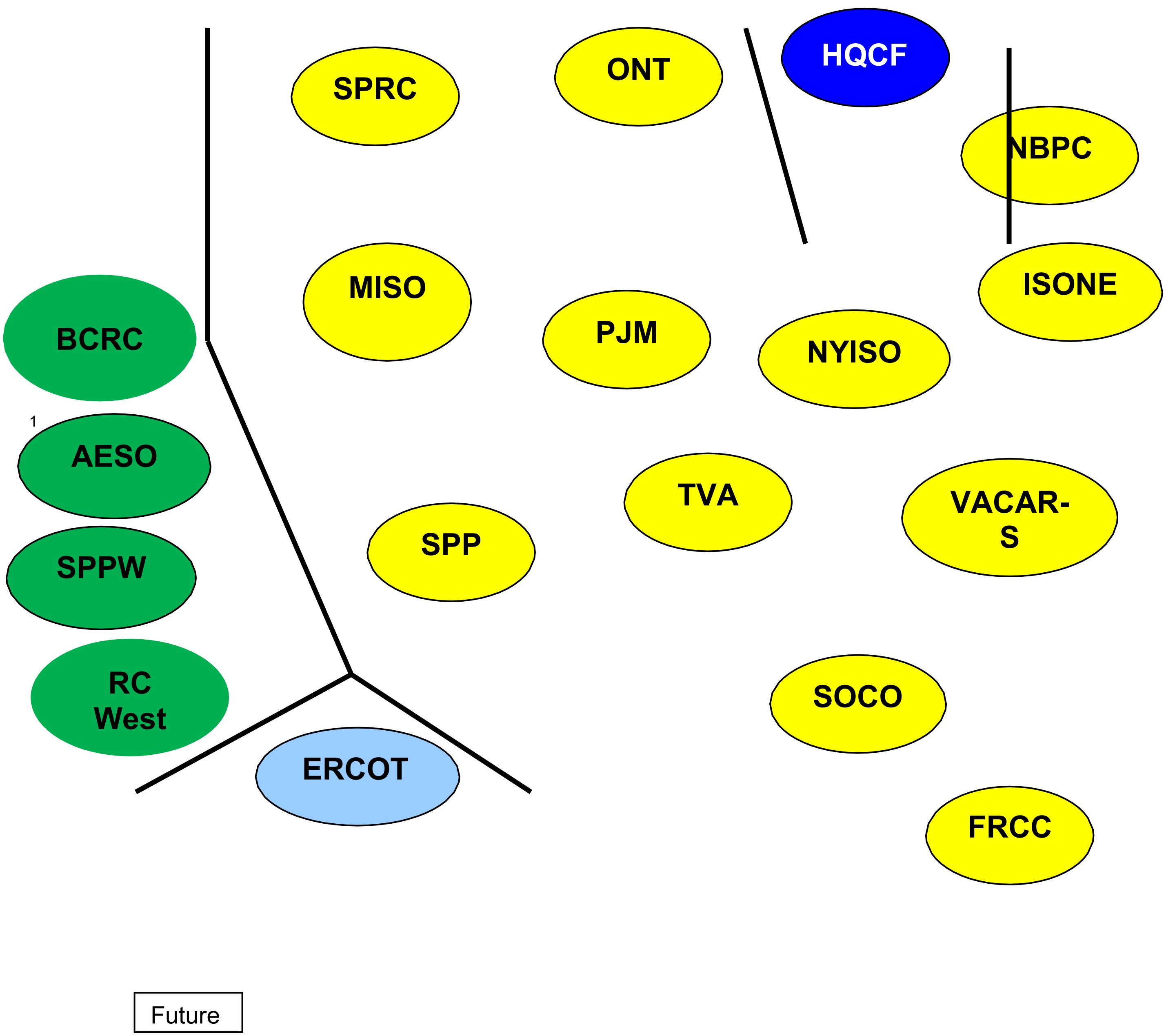
iv. Quebec – Martin Boisvert

13. IDC SC Update – Matt Vos, IDC Chair, IESO; Chris Wakefield, Vice Chair *(5 minutes)*

Adjourn Open Session

NERC RELIABILITY COORDINATOR AREAS

Effective: December 3, 2019



[1] AESO is currently providing their own Reliability Coordinator services consistent with Alberta legislation.

NERC RELIABILITY COORDINATOR DESKS

Effective: December 3, 2019

CURRENT RELIABILITY COORDINATOR	FUTURE RELIABILITY COORDINATOR	COMMENT
HQCF	Same	
ONT (IESO)	Same	
ISONE	Same	
NBPC	Same	
NYISO	Same	
PJM	Same	
MISO (Carmel, Eagan, Little Rock)	Same	
SPRC	Same	
VACAR–S	Same	
TVA	Same	
SOCO	Same	
FRCC	Same	
SPP/SPPW	Same	
ERCOT	Same	
AESO RC[2]	Same	
RC West	Same	
BC Hydro	Same	

2 AESO is currently providing their own Reliability Coordinator services consistent with Alberta legislation.

NERC
BALANCING AUTHORITY TO RELIABILITY COORDINATOR MAPPING
December 3, 2019

This table indicates the Reliability Coordinators associated with each Balancing Authority within each Interconnection.

Current Reliability Coordinator	*Balancing Authority*	*Local Balancing Authority*	*Future Reliability Coordinator*	*Regional Entity*	*Expected Date For Change*
HQCF	HQCF			NPCC	
ISONE	ISNE			NPCC	
NBPC	NBPC			NPCC	
	NSPI			NPCC	
NYISO	NYIS			NPCC	
ONT	ONT			NPCC	
PJM	PJM			RF/SERC	
VACAR-S	DUK			SERC	
	SCEG			SERC	
	SC			SERC	
	CPLW			SERC	
	YAD			SERC	
	CPLE			SERC	
TVA	LGEE			SERC	
	TVA			SERC	
	AECI			SERC	
SOCO	SOCO[1]			SERC	
	SEPA			SERC	
	Power South Electric Cooperative[2] (PSEC)			SERC	(PESC) deregistered as a Balancing Authority in September 2021 and the load and generation was merged into the Southern Balancing Authority Area
FRCC	FMPP			SERC	
	FPC (DEF)			SERC	
	FPL			SERC	
	GVL			SERC	
	HST			SERC	
	JEA			SERC	

[1] Power South Electric Cooperative (PSEC) BA merged into SOCO BA footprint in September 2021. PSEC was formerly Alabama Electric Cooperative (AEC) and changed names in 2008

[2] PSEC BA formerly AEC is now merged in to SOCO BA footprint as of September 2021

	NSB			SERC	
	SEC			SERC	
	TAL			SERC	
	TEC			SERC	
MISO	MISO			RF/SERC/MRO	
		MECS		RF	
		CIN		RF	
		HE		RF	
		IPL		RF	
		DECO		RF	
		NIPS		RF	
		SIGE		RF	
		MIUP		RF	
		WEC		RF	
		CONS		RF	
		WPS		RF	
		BREC		SERC	
		AMIL		SERC	
		AMMO		SERC	
		CWLD		SERC	
		CWLP		SERC	
		SIPC		SERC	
		GridLiance Heartland		SERC	
		EES		SERC	
		CLEC		SERC	
		LAFA		SERC	
		LEPA		SERC	
		LAGN		SERC	
		SME		SERC	
		HMPL		SERC	
		ALTE		MRO	
		ALTW		MRO	
		MGE		MRO	
		UPPC		MRO	
		GRE		MRO	
		MEC		MRO	
		MP		MRO	
		MPW		MRO	
		NSP		MRO	
		OTP		MRO	
		SMP		MRO	
		DPC		MRO	
	MHEB			MRO	
AESO[3]	AESO			WECC	

[3] AESO is currently providing their own Reliability Coordinator services consistent with Alberta legislation.

Current Reliability Coordinator	*Balancing Authority*	*Local Balancing Authority*	*Future Reliability Coordinator*	*Regional Entity*	*Expected Date For Change*
BCRC	BC Hydro			WECC	
RC West	BANC			WECC	
	CENACE			WECC	
	IID			WECC	
	LAWP			WECC	
	TID			WECC	
	CAISO			WECC	
	GWA			WECC	
	AVA			WECC	
	BPAT			WECC	
	CHPD			WECC	
	DOPD			WECC	
	GCPD			WECC	
	IPCO			WECC	
	NWMT			WECC	
	PGE			WECC	
	PACW			WECC	
	PSEI			WECC	
	SCL			WECC	
	WWA			WECC	
	TPWR			WECC	
	PACE			WECC	
	AZPS			WECC	
	PNM			WECC	
	NEVP			WECC	
	SRP			WECC	
	AVRN			WECC	
SPRC	SPC			MRO	
ERCOT	ERCO			Texas RE	
SPPW	TEPC			WECC	
	WACM			WECC	
	WALC			WECC	
	HGMA			WECC	
	PSCO			WECC	
	EPE			WECC	
	DEAA			WECC	
	GRIF			WECC	
	WAUW			WECC	
	Gridforce Energy Management (GRID)			WECC	
	BNBA			WECC	
SPP	SWPP			MRO	
	SPA			MRO	

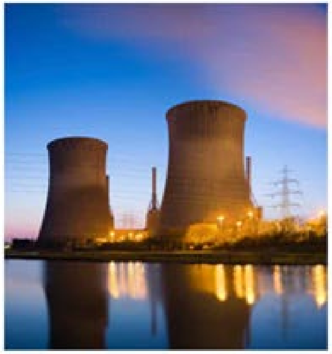
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Real Time Operating Subcommittee

2025 Work Plan

Christopher Wakefield, Chair, Southern Company
Derek Hawkins, Vice chair, Southwest Power Pool

RELIABILITY | RESILIENCE | SECURITY

RTOS Work Plan Item #1

- Work Plan item name: EIDSN
- Work Plan item detailed description: Monitor development of common tools and act as point of contact for EIDSN.
- Scheduled completion date: On-going
- Applicability to address:
  - Cyclical Work Task
- Priority: M
- Status: On-going

RTOS Work Plan Item #2

- Work Plan item name: Frequency Monitor Reporting (Standing RTOS agenda item to discuss).
- Work Plan item detailed description: Frequency Monitor Reporting (Standing RTOS agenda item to discuss).
- Scheduled completion date: On-going
- Applicability to address:
  - Cyclical Work Task
- Priority: M
- Status: On-going

RELIABILITY | RESILIENCE | SECURITY

RTOS Work Plan Item #3

- Work Plan item name: IROL Guideline
- Work Plan item detailed description: Reliability Guideline: Methods for Establishing IROLs – RTOS to review guideline and recommend update, retire, or ?
- Scheduled completion date: ~2025
- Applicability to address:
  - RISC Report
- Priority: M
- Status: RTOS IROL Sub Team formed
  - Under RTOS review

RTOS Work Plan Item #4

- Work Plan item name: IROL Report Recommendations
- Work Plan item detailed description: RTOS provide recommendations
- Scheduled completion date: 2025
- Applicability to address:
  - IROL Report
- Priority: M
- Status: In-Progress

RTOS Work Plan Item #5

- Work Plan item name: RTOS Scope Review
- Work Plan item detailed description: Regular 3-year review of the RTOS Scope
- Scheduled completion date: 2025
- Applicability to address:
  - Administrative
- Priority: L
- Status: In-Progress

Questions and Answers

SPP RELIABILITY PLAN

0820EXT00108

Business Owner: Derek Hawkins
Effective: 02/01/2024
Revised: 02/01/2024
Version: 7.0

Approved By:	
SME Signature (Brian Strickland)	Date

Approved By:	
Business Owner Signature	Date

Revision History

Author	Version	Revision Date	Effective Date	Description
ORWG	1.0	6/1/05		Complete re-write to align with revised NERC Policy 9 as approved by NERC 06/15/04.
		6/15/05		Per NERC ORS request, removed Appendix B – Reliability Assessment Process and Procedure.
		1/11/06		Added CLECO to the plan.
		1/26/06		Added Constellation Balancing Authorities BCA, CNWY, DENL, DERS, PUPP, and WMUC to the plan.
		1/27/06		Updated to reflect changes in SPP processes and procedures after the SPP EIS Market is implemented.
		2/9/06		Made necessary changes to conform with NERC functional model terminology present in existing reliability standards.
		9/8/06		Added LAGN to the plan with an effective date of November 1, 2006
		12/5/06		Added Constellation Balancing Authority BUBA
		1/1/09		Changes consistent with Criteria 12.3. Corrected Batesville Generating Station acronym from BCA to BBA. Added Missouri Public Service (MPS) to footprint.
		4/1/09		Added Nebraska entities – LES, NPPD and OPPD
		10/1/09		Added Constellation Balancing Authorities OMLP and PLUM
		4/1/10		DENL Balancing Authority moved from operation by Constellation to operation by NRG and changing DENL to NLR
		1/1/11		CNWY and WMUC Balancing Authority moved from operation by Constellation to operation by NRG and changed from CNWY to CWAY and from WMUC to WMU
		2-15-11		City Utilities of Springfield (SPRM) becoming a stand-alone Balancing Authority Areas instead of a TOP imbedded inside the SPA Balancing Authority Areas.
		4/11/12		Added Brazos Electric to list of Balancing Authorities. Updated map to reflect addition. Changed “OPS1” application in reference to outage scheduling to “CROW” application reference. Clarified the RTCA and monitored elements by voltage in sections C.4. and E1. Noted the primary and BUCC location changes in 2012 in section I.

Author	Version	Revision Date	Effective Date	Description
		6/1/13		Transferred the southern reliability members from SPP to MISO (with exception of the CECD entities) per Entergy move to MISO
		12/19/13		Removal of the CECD entities from the SPP Reliability footprint. Changed cover page date to Dec 19, 2013.
		3/1/14		Replaced “EIS” with “Integrated”, removed OPS1 references, replaced PowerWorld with E-terravision, removed member map, and changed list of BA/TOPs to reflect new consolidated BA (SPP BA).
		6/1/15		Added the IS entities of WAPA, Corn Belt to the TOP list within the Introduction and the SPP Reliability Areas. Changed WECC references to PEAK Reliability.
	2.0	4/21/16		Changes made due to overall review, and to correct studies, update tools, Operating Criteria changes, DC tie additions, reduce redundancy of sections and Market constraint management.
Terry Oxandale	3.0	4/30/2019	4/30/2019	Modified for SPP RC for Western Interconnect effective 12/3/2019. Added changes in RE, additional TOPs in the Appendix A, and included aspects of the Western Interconnect not included in the current Eastern Interconnect practices. Converted to current template and assigned new Operations document ID 0820PCS00108.
Brian Strickland, Derek Hawkins	3.1	11/20/2019	11/20/2019	Updated with additional information on loss of necessary applications, weather, Cyber Attack, and SPS/RAS. Updated AZPS (under CAISO RC) to AEPC (under SPP RC). Updated for clarifications per RCRT review. Deleted Gila River Power (GRMA) from Appendix A table being they are not a TOP per Bryan Wood.
Brian Strickland, Yasser Bahbaz	3.2	2/10/2021	4/1/2021	Added GRID effective 4/1/2021 to “BAs and TOPs in SPP RC Areas” section in Appendix A. Also updated file name of documents referenced in Appendix B.
Brian Strickland	4.0	1/07/2022		Added language to GMD to address monitor responsibilities and added a section on voltage. Changed business owner and SME per B. Wood.
Julie Gerush, Brian Strickland	5.0	04/12/2023	04/12/2023	Comments addressed from Operations review. Changes to accommodate changes to IDC. Updated cover pages.

Author	Version	Revision Date	Effective Date	Description
Heather Harris, Brian Strickland	6.0	04/01/2024	04/01/2024	Removed Appendix B (RC Related procedures), updated to identify no delegation of task or actions requested for adjacent RCs, minor language changes to mirror requirement language. Removed GRIF under entities due to merger with GRID. Added language for SOL/IROL communication and general cleanup Changed document ID.
Hayden Johnson	7.0	02/01/2025	02/01/2025	Added First Light Energy (BNBA) to the list of BAs/TOPs in the Appendix.

TABLE OF CONTENTS

Introduction

The North American Electric Reliability Corporation (NERC) delegates its authority to monitor and enforce compliance with NERC Reliability Standards to the Regional Entities (RE). The RE carries out their reliability activities with the Registered Entities for their reliability region. Southwest Power Pool (SPP) is recognized as the Reliability Coordinator (RC) for all Transmission Operators (TOPs) and Balancing Authorities (BAs), listed in **Appendix A**, in both the Eastern and Western Interconnections.

SPP RC is responsible for the bulk transmission reliability and power supply reliability within its RC Areas. Bulk transmission reliability functions include assessment of real-time and next day operating conditions, congestion management, coordination of transmission and generation outages and instructing curtailment of transactions and/or load. SPP RCs use a risk-based approach to communicating actual and potential SOL exceedances with impacted TOPs, as described in SPP's Reliability Coordinator Area System Operating Limit Methodology and Reliability Coordinator Area System Operating Limit Methodology Western Interconnection. Power supply reliability entails monitoring BA Areas performance and coordinating BAs and TOPs actions, including instructions, for load curtailment, generation and transmission actions, and adjustments to voltage schedules in situations where the system is in jeopardy. SPP RC procedures and policies are consistent with those of NERC.

Operating agreements are in place to facilitate communication, notification, exchange of information, and coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.

SPP RC communication mediums include phone, the SPP Reliability Communications Tool (R-Comm), the Reliability Coordinator Information System (RCIS), email, NERC Hotline, cellular phones, satellite phones, etc.

NOTE: Unless explicitly defined, any reference to "RC" is applicable to both East and West.

A. Responsibility and Authority

1. SPP has a wide-area view, operating tools, processes, procedures, authority and responsibility for the reliable operation of the Bulk Electric System (BES) within the SPP RC Areas in accordance with NERC Reliability Standards including applicable regional variances, the SPP Membership Agreement, SPP Required Data Specification (RDS), and SPP Reliability Customer agreements. These executed agreements are posted on the SPP website under SPP Documents & Filings/Governing.

    1.1. The SPP RC has a wide-area view, operating tools, processes and procedures to prevent or mitigate emergency operating situations in next day analysis and real-time conditions. More details are provided in appropriate sections of this document.

1.2. The executed agreements give the SPP RC clear decision-making authority to act and instruct actions to be taken by the SPP RC Members and Reliability Customers to preserve the integrity and reliability of the BES. SPP's responsibilities and authorities, as well as its RC members' and customers' responsibilities are clearly defined in SPP's governing documentation.

2. SPP acts first and foremost in the best interest of the BES before that of any other entity. This expectation is clearly identified in the SPP Membership and Reliability Customer agreements, and in the job description of the SPP personnel acting in the role of the RC.

3. Per the SPP RC Member and Reliability Customer agreements, the BAs, TOPs, and other operating entities in the SPP RC Areas (i.e. West and East RC Areas) shall carry out required emergency actions as instructed by the SPP RC, including the shedding of firm load if required, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. In those cases, SPP RC Members or Reliability Customers must immediately inform the SPP RC of the inability to perform the operating instruction.

4. Weather-related event is to be determined in advance, based on weather evaluations, storm information, next day studies, etc., for action to be taken by SPP RC as necessary. The evaluation and coordination of analysis information may lead to issuing a Weather Alert or Conservative Operations. In a coordinated effort, SPP has a process to exchange information related to weather events where SPP or a portion of SPP expects temperatures at a level that is of concern, or where tornado, ice storm, or high wind might be forecasted. Weather Alerts may be issued to prepare personnel and facilities for expected extreme weather conditions.

   4.1 For the Western Interconnection, SPP has a process to exchange information related to potential reliability impacted weather events, including utilizing R-Comm, emails, satellite phones, etc.

5. SPP Information Technology (IT) group maintains an awareness and level of protection from Cyber Attacks. SPP IT group has a process to determine if and when notifications should be made to Operations staff to increase awareness of potential cyber activities. In the event that Operations suspects or detects a Cyber Attack first, they will follow the process in accordance with the SPP Sabotage Procedure to notify the necessary parties.

6. In the event of the loss of a necessary application, SPP shall notify neighboring RCs, BAs, and TOPs to monitor the SPP RC Areas footprint when necessary.

B. Responsibilities – Delegation of Tasks

The SPP RC has not delegated any RC tasks. Communication and coordination are completed with adjacent RCs, yet no request for delegation of task or action is requested.

C. Common Tasks for Next Day Operations

1. SPP coordinates operations and ensures reliable operation of the BES by utilizing System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) during the real-time and next day operating horizons for the SPP RC Areas including additional thermal, voltage and stability-related analysis as necessary. SPP will communicate and coordinate the results of its reliability assessments with those performed by the SPP RC Members and Reliability Customers, to ensure that any potential or actual SOL exceedances are properly identified and reported. SPP models a sufficient wide-area view to ensure properly coordinated operations with neighboring RCs. SPP will share its Operational Planning Analysis (OPA) via its secure FTP site.

2. SPP is responsible for determination of IROLs within the SPP RC Areas, and does so via documented methodologies. As part of the daily OPA and/or RTA, SPP highlights additional potential SOLs. That list of potential SOLs and the existing list of SOLs are screened for potential IROL criteria. The potential IROL condition will be reviewed further by evaluating the system response to the loss of the SOL violated facility. The original potential IROL contingency will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing SOL violated facility contingency results in cascading outages or widespread voltage problems, unless there are studies or system knowledge that the SOL is not an IROL. Additionally, when temporary constraints are defined for various operating circumstances identified through OPA and/or RTA, this process is performed to verify if an IROL exists. SPP disseminates IROL information within its RC Areas and with neighboring RCs.

3. SPP ensures that SPP RC Members and Reliability Customers operate to prevent the likelihood that a disturbance, action or non-action in the SPP RC Areas will result in an SOL or IROL exceedance in another entity of the Interconnection. SPP's RC Members and Reliability Customers are required to adhere to NERC Reliability Standards. SPP is required by its seams agreements with its neighbors to coordinate maintenance outages in such a way that impacts on the other systems' reliability are minimized. SPP performs OPA on a daily basis for the next day. If a potential SOL or IROL exceedance is observed on a neighboring party's system, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan, if one does not already exist. In instances where there are differences in operating limits derived by SPP and its neighbors or between SPP entities, SPP will operate to the most conservative result until the reasons for these differences can be identified and an agreement is reached.

4. SPP ensures that its RC Members and Reliability Customers are always operating under known and studied conditions and ensures that they reassess and re-posture their systems following contingency events within 30 minutes. SPP performs next day OPA pursuant to the Reliability Assessment Process Overview. These analyses are performed for each day. These analysis model peak conditions for the day being studied including scheduled generation and transmission outages and anticipated generation dispatch to support the forecasted load plus net interchange. SPP performs an N-1 contingency analysis monitoring the post-contingency flow of both SPP and neighboring system facilities. If a potential SOL or IROL exceedance is observed, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan if one does not already exist.

   SPP performs a next-day assessment of capacity and adequacy for each hour of the day, as well as a next-hour assessment of capacity and adequacy on an hourly basis. These analyses model peak conditions for the day/hour being studied including scheduled generation and transmission outages and anticipated generation dispatch to support the forecasted load plus net interchange. If a capacity issue is observed, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan.

   SPP monitors, in real-time, all facilities considered critical. In the SPP EMS, real-time flows on all critical facilities are monitored and alarmed at the facility ratings, SOL and IROL levels. SPP tracks real-time and applicable post-contingency flows on all constraints and alarms when applicable SOLs and IROLs are approaching the limit or are exceeded. Additionally, when any identified IROL is exceeded in real-time, an email notification of the exceedance is sent to operations management and engineering staff to initiate post-event analysis.

   SPP also uses a State-Estimator solution to run its Real-Time Contingency Analysis (RTCA) application at least every 6 minutes. SPP has defined all branches and transformers with low side voltages of 115 kV and higher (with some 69kV) within the SPP RC Areas and all branches and transformers with low side voltages of 230 kV and higher within the first-tier BA Areas as contingencies in RTCA. SPP monitors the post-contingency flow on all SPP branches and transformers with low side voltages of 115kV and higher. Alarms are triggered if that flow exceeds the emergency rating of the branch or transformer. Additionally, SPP monitors post-contingency flow on all branches and transformers with low side voltages of 230 kV and higher within neighboring systems as well as selected lower voltage facilities within neighboring systems that are known to be impacted by an SPP contingency. The RC receives alarms for any RTCA exceedance.

5. The SPP RTO acts as the Transmission Service Provider (TSP) for all Transmission Owners in the Eastern Interconnection, subject to the SPP Tariff. For these entities,

SPP uses Flowgates as proxies for transmission limitations in the determination of ATC. The same Flowgates monitored in real-time by the SPP RC and their associated SOLs are also incorporated in the models used by SPP to calculate ATC and administer its OATT. SPP limits sales of transmission service to the SOLs of all identified Flowgates. When a need for a new Flowgate is determined by the SPP RC, the new Flowgate is included in the models used by the SPP TSP for calculation of ATC. These Flowgates are posted on the SPP OASIS.

5.1 SPP is not the TSP in the Western Interconnection, with the exception of WAUW.

6. SPP communicates reliability Operating Instructions in a clear, concise, and definitive manner. Per SPP RC procedures, the SPP RC requires the recipient to repeat back any reliability Operating Instructions communicated by the SPP RC. Proper communications protocols are included in Operator training provided by SPP.

D. Next Day Operations

1. SPP performs an OPA to identify potential SOL and IROL exceedances pursuant to the Daily Reliability Assessment Procedure. These analyses are performed daily with the exception of the weekend and holiday analyses being performed on the previous Friday, or day prior to the holiday. SPP's day-ahead reliability assessment consists of off-line PSS/E studies of the modeled system conducted by the Operations Engineering staff. Contingency-based analyses are conducted daily, which include Remedial Action Schemes (RAS). In these contingency analyses, at a minimum, SPP includes BES facilities in SPP and first-tier area above 100 kV as contingencies, and monitors facilities above 100 kV. SPP will include other facilities identified with impact to BES or with significant risk to the BES. SPP also runs a 7-day contingency analysis to review upcoming operating conditions over the next week for the Eastern Interconnection. Planned transmission and generation outages within the SPP RC Areas are coordinated with adjacent RCs. Outages external to the SPP RC Areas are obtained from neighboring RCs. Peak conditions are modeled using anticipated generation dispatch to support the forecasted load plus expected scheduled net interchange.

   1.1 If, in the next day OPA, parallel flows from the SPP RC Areas are observed as causing a potential problem on a neighboring system, SPP will contact the neighboring RC and coordinate to determine if the problem could result in an SOL or IROL exceedance. If it is agreed that an exceedance could occur, SPP will coordinate with the neighboring RC to develop an appropriate mitigation plan, if one does not already exist. The mitigation plan will identify appropriate actions to be taken to prevent the exceedance from materializing which may include creation of appropriate constraints to be monitored, commitment of appropriate generation capacity, reconfiguration of the transmission system, or re-dispatch of generation as well as actions to be taken in the event the exceedance materializes in real-time, including identifying potential transmission system reconfigurations, generation that can be re-dispatched, schedules that can be curtailed, and, if necessary, load that can be shed.

2. SPP receives operating information, such as transmission and generation facility maintenance schedules, tap settings, and generation resource plans, required for performing an OPA from responsible SPP RC Members and Reliability Customers. The applicable SPP RDS requires SPP RC Members and Reliability Customers to submit the necessary data to SPP. SPP receives similar information from its neighbors. SPP uses load forecast, generation forecast, and/or tag data as its basis for incorporating Interchange Transactions into the OPA.

3. SPP shares the results of its OPA, when conditions warrant, or upon request, with other RCs. SPP also posts the results of its analyses via its secured FTP site for appropriate SPP RC Members, Reliability Customers, and neighboring RCs. If the results of the OPA indicate potential reliability problems and efforts outlined in (4.) below do not resolve the potential condition, the SPP RC issues the appropriate alerts via the RCIS.

4. The SPP RC initiates conference calls, or other appropriate communications, such as R-Comm, as necessary when conditions revealed by the OPA warrant. Conditions that warrant communications with other RCs include potential IROL exceedances determined as described in part 1.1 of this section and capacity deficiencies that could result in shedding of firm load.

E. Current Day Operations

1. SPP monitors facilities within the SPP RC Areas and adjacent RC Areas to ensure determination of potential SOL and IROL exceedances.

    1.1 SPP will make reasonable efforts to provide notice to a neighboring RC if SPP identifies a potential reliability problem in that RC's Areas. If both parties agree that a reliability problem exists, SPP will coordinate with its neighboring RCs any actions required to mitigate the situation. In the event that all parties cannot agree on the reliability issue, SPP will follow the most conservative approach. This coordination may include evaluation of the impact of maintenance and forced outages on the situation, implementation of existing emergency procedures or operating guides, reconfiguration of the transmission system, curtailment of point-to-point transactions, re-dispatch of generation, and load shedding.

2. In the SPP EMS, real-time flows on all critical facilities are monitored and alarmed at both SOL and applicable IROL levels. SPP uses constraint monitoring applications that track post-contingency flows on all constraints and alarms as applicable SOLs

and IROLs are approached and/or exceeded. Post-contingency flows on constraints are calculated using real-time flows and Line Outage Distribution Factors (LODFs) that are updated to reflect current system topography.

3. SPP monitors the necessary RC Area's parameters to ensure it is continuously aware of conditions within the SPP RC Areas.

3.1. SPP monitors the status of BES elements using an EMS complete with State Estimator, Alarming, Real-Time Contingency Analysis, and Power Flow applications. SPP receives the data necessary to maintain the EMS from its RC Members and Reliability Customers in accordance with applicable SPP RDS.

3.2. The SPP EMS model represents the SPP RC Areas, neighboring BA Areas and other portions of the Eastern and Western Interconnection. For the Eastern Interconnection, SPP's RC Area represents approximately one-third of the SPP EMS network model of Eastern Interconnection facilities. The EMS uses near real-time measurements received from these same entities via ICCP.

3.2.1. For the Western Interconnection, SPP maintains a full model referenced from the Western Interconnection-wide Model (WIM) consistent with the Western Interconnection Modeling and Monitoring Methodology.

3.3. SPP monitors, in real-time, pre-contingent and anticipated post-contingent element conditions. This is achieved through the EMS and constraint monitoring tools which utilize real-time Line Outage Distribution Factors based on the latest system topology.

3.4. SPP monitors real-time flows and statuses of facilities 100 kV and above and select lower voltage facilities in the Eastern Interconnection. Contingencies of facilities with low side voltages of 115kV and higher within the SPP RC Areas as well as those with low side voltages of 230 kV and higher within neighboring systems are studied. The post-contingent flow on facilities with low side voltages of 115kV and higher within the SPP RC Areas as well as those with low side voltages of 230 kV and higher within neighboring systems are monitored.

3.4.1. For the Western Interconnection, the monitoring of facilities is consistent with the Western Interconnection Modeling and Monitoring Methodology agreed upon according to applicable NERC standards.

3.5. SPP monitors real and reactive reserves. SPP receives real-time operating reserves data from its RC Members and Reliability Customers, and compares this data to the operating reserves required. SPP monitors and displays the reactive output of generators within the SPP RC Areas as well as the remaining reactive capability by BA Area. SPP receives real-time voltages on critical buses which alarm the RC when a voltage limit is exceeded. SPP will contact the appropriate TOP or BA as necessary to develop mitigation plans. SPP RC makes all reasonable efforts to provide notification and coordination of actions that may impact adjacent RC Areas for voltage control, including coordination of reactive resources.

3.6. SPP monitors voltage points based upon a ±5% tolerance around nominal voltage. This tolerance may vary per TOP and for nuclear power stations. When a high or low voltage alarm is received from the EMS system indicating limit violations, SPP will coordinate with the affected TOP to determine if the indicated voltage is correct and verify the TOP's voltage limits for that particular area. SPP will assist the affected TOP in developing a course of action to address undesirable voltage conditions including verifying and changing status of static reactive devices, reconfiguration, coordinating resource commitments, establish power transfer limits and re-dispatch as appropriate, etc.

3.7. The SPP RTO within the Eastern Interconnection monitors capacity and adequacy conditions through the SPP Reserve Sharing System (RSG) and market applications. SPP also receives resource plan information for all resources participating in the SPP Integrated Marketplace (Eastern Interconnection). This information contains data for each resource for each hour of a 7-day horizon beginning with the current day and is updated as necessary throughout the day. SPP will use this and other system information to perform hourly assessments of capacity and adequacy for the next hour.

3.7.1. For the Western Interconnection, SPP West RC will monitor capacity and adequacy conditions utilizing applicable RSG and BA submitted data as documented in the required data specifications.

3.8. SPP monitors current ACE and frequency in real-time for all BA Areas in the SPP RC Areas using the real-time data sent by the BAs through ICCP pursuant to applicable SPP RDS. This information is displayed to the SPP RC constantly.

3.9. SPP monitors current external impacts on its system from external network load, Market flows in the Eastern Interconnection, external generation to load (GTL) and transactions.

3.10. SPP receives and reviews resource plans and generation schedules from its Reliability Customers.

3.11. SPP monitors planned and unplanned transmission and generation outages. SPP's RC Members and Reliability Customers are required to submit all generator and transmission outages. Timing requirements and approval procedures are documented in the applicable SPP Outage Coordination Methodology and applicable SPP RDS. The generator and transmission outages are sent to the Outage Scheduler database of the EMS system and used by the State Estimator and RTCA if the real-time measurements of the facility do not contradict with the submitted outage. The SPP RC Operators are constantly verifying the submitted outage data using State Estimator displays and its alarming application. They contact the appropriate SPP RC Member or Reliability Customer if a scheduled outage does not materialize in real-time as planned or if a line, transformer or unit trips without having a scheduled outage.

SPP utilizes graphical display systems designed to increase SPP RC situational awareness of the SPP RC Areas. The systems use near real-time and/or EMS data to provide a wide-area view.

4. SPP monitors BES parameters that may have significant impacts upon its RC Areas and neighboring RC Areas as follows:

4.1. SPP maintains awareness of all Interchange Transactions that wheel-through, Source, or Sink in the SPP RC Areas.

4.1.1. SPP acts as a Scheduling Entity on behalf of the Market Operating Entities or PSEs in its Eastern Interconnection RC Area by approving all transactions that wheel-through, Source and Sink in its Eastern Interconnection RC Area. SPP makes available its Eastern Interconnection RC tag information to all RCs in the Eastern Interconnection as necessary.

4.1.2. SPP is not a scheduling entity in the Western Interconnection. The RC maintains awareness of scheduling impacts on constraints through the Enhanced Curtailment Calculator (ECC).

4.2. SPP evaluates and assesses additional Interchange Transactions that could violate SOLs and/or IROLs. SPP utilizes Interchange information, real-time data in the SPP EMS, and SPP’s constraint monitoring tools to make an assessment of the impacts of additional transactions on constraint loading. SPP is authorized to utilize all resources, including load shedding, to address a potential or actual IROL exceedances. This authorization is reiterated to each SPP RC Operator in their job description and by a personal memorandum from SPP’s Chief Operating Officer (COO).

4.3. SPP monitors operational data submitted by BAs within the SPP RC Areas to ensure that the required amount of Operating Reserves are provided and available as required to meet NERC Control Performance Standards (CPS) and Disturbance Control Standards (DCS). If necessary, SPP will instruct the BAs in the SPP RC Areas to arrange for assistance from neighboring BAs. SPP has the authority to instruct the acquisition of generation capacity and, if that instruction is not satisfied, instruct the shedding of load in the deficient BA Areas.

4.4. SPP will identify the cause of potential or actual SOL or IROL exceedances. SPP shall initiate control actions or emergency procedures to relieve the potential or actual IROL exceedance without delay, and no longer than 30 minutes. SPP will choose the most effective means of relieving the IROL exceedance within 30 minutes including instructing generation re-dispatch, facility switching, and load shedding. SPP is authorized to instruct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance.

4.5. SPP will communicate start and end times for time error corrections to all BAs within its RC Area in both the Eastern and Western Interconnections.

4.6 SPP will review TOP submitted Geo-Magnetic Disturbance (GMD) plans and acknowledge, via email, of both receipt and review. SPP will ensure that all TOPs and BAs within its RC Areas are aware of GMD forecast information and will assist in the development of any required response plans. For GMD levels K8 or above, SPP RC will initiate a satellite phone call test to ensure satellite phone functionality has not been damaged during the event. SPP will communicate GMD forecast information to its BAs and TOPs via one or more of the following; R-Comm, email communication, ICCP, and/or phone communication.

While performing the role of the GMD monitor, for all K-7 or higher GMD warnings and alerts, SPP will participate in the Space Weather Prediction Center (SWPC) initiated phone communication with other Reliability Coordinators via the NERC Hotline and perform a roll call of RCs expected to participate. As the GMD monitor, SPP RC will contact RCs who did not participate in the SWPC call, provide details concerning the GMD notification and post a message to the Reliability Coordinator Information System and, for the Western Interconnection RCs, to R-COMM utilizing the blast message option outlining the GMD event information.

4.7. SPP will participate in NERC Hotline discussions, assist in the assessment of the reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. SPP will disseminate this information within its RC Areas as necessary.

4.8. SPP monitors system frequency and its BAs' performance, and if necessary, will instruct any rebalancing required for a BA to return to CPS and DCS compliance to ensure reliability. SPP receives at least one real-time frequency point via ICCP for each Balancing Authority Areas in the SPP RC Areas. At the instruction of SPP, its BAs shall utilize all resources, including firm load shedding, to balance load and generation.

4.9. SPP coordinates with other RCs and neighboring BAs or TOPs, as needed, in the development and implementation of mitigation plans for potential or actual SOL, IROL, CPS or DCS exceedances. SPP coordinates pending generation and transmission maintenance outages with other RCs, as necessary, in both the real-time RTA and next day OPA timeframes. SPP participates in periodic conference calls with neighboring RCs as necessary.

4.10. SPP will assist the BAs in the SPP RC Areas in arranging for assistance from neighboring RCs or BAs by issuing reserve sharing contingency notifications (for the Eastern Interconnection SPP RSG Members) or EEAs as appropriate.

4.11. SPP identifies sources of large ACEs that may be contributing to frequency, time error, or inadvertent interchange and will implement corrective actions with the appropriate BA. SPP receives the real-time ACE for each BA Area in the RC Areas via ICCP. The SPP RC receives an alarm if any ACE values change significantly or exceed a predefined limit. Excessive ACEs would be addressed by a call to the BA to determine the cause of the deviation and the course of action that the BA has planned and/or implemented to address the situation. Assistance would be provided in the Eastern Interconnection RC Areas by accessing operating reserves with the SPP Reserve Sharing Group to address the deviation should that be required. Should the situation be causing overloads on system facilities, instruction would be issued to dispatch/re-dispatch generation to relieve the situation.

4.12. SPP maintains awareness that Special Protection System (SPS) or Remedial Action Scheme (RAS) within the SPP RC Areas are armed. The host BA/TOP is required pursuant to applicable SPP RDS to keep SPP informed of the operational status of the SPS. If there is concern with the state of an SPS/RAS, and if not previously informed, the RC shall contact the responsible TOP, or neighboring entity as applicable, to inquire about the SPS/RAS state change.

5. SPP will alert all affected BAs and TOPs in its RC Areas, and all affected RCs within the Interconnection when it foresees an IROL exceedance or a significant loss of real and/or reactive generation capacity within its RC Areas through OPA and/or RTA. SPP will disseminate this information to its BAs and TOPs, utilizing appropriate communication channels, such as R-Comm, verbal communications, etc.

6. SPP confirms RTA and/or OPA results and determines the effects within its RC Areas and adjacent RC Areas. SPP will derive and discuss options to mitigate potential or actual SOL or IROL exceedances and identify and implement only those actions as necessary as to always act in the best interest of the Interconnection at all times.

Communication and coordination are completed with adjacent RCs, yet no request for delegation of task or action is requested.

F. Emergency Operations

1. In the event the loading of transmission facilities progresses to, or is projected to progress to, an SOL exceedance, SPP will use congestion management processes to reduce the loading to prevent an exceedance as soon as practicable. In the event the loading of transmission facilities progresses or is projected to progress to an IROL exceedance, SPP will take immediate actions, but no longer than 30 minutes, to return loading to the facility rating up to and including load shed.

2. SPP maintains copies of all pertinent operating guides/instructions as supplied by SPP RC Members and Reliability Customers. SPP reviews and coordinates these instructions with the BAs and TOPs in the SPP RC Areas. The SPP RC Operator maintains communication with the Transmission Operator who may be implementing these guides for local area relief to ensure regional reliability is not jeopardized by the implementation of said procedures. SPP RC Operators will instruct the appropriate Transmission Operators to take specific actions on how to mitigate the situation.

3. For the Eastern Interconnection RC Area, SPP will comply with the provisions of the NERC TLR procedure as follows. If the SPP RC is the sink RC and receives notification via the IDC that another RC has issued a TLR that calls for curtailment and/or halts of transactions sinking in SPP, the SPP RC will use the IDC to acknowledge the transaction curtailments and/or halts for the next hour, or current hour, and monitor the transactions to ensure that the transaction curtailments/halts are properly implemented. SPP acts as the sink RC in the IDC for transactions sinking into ERCOT across the East and North DC ties and for transactions sinking into Western Interconnection across the Eddy County, Stegall, Blackwater, Rapid City, Miles City, Lamar and Sidney HVDC ties.

    3.1. If SPP determines, through Source-to-Sink impact evaluation, that curtailment of a transaction as identified by the IDC would actually increase flows on the constraint for which relief has been requested, it will not acknowledge curtailment of such transaction. SPP may also determine that, through Source-to-Sink impact evaluation, transactions having a significant impact on the constraint exist but are not identified for curtailment by the IDC. In those cases, SPP will instruct curtailment of those transactions as necessary.

    3.2. If SPP receives notification from the IDC that SPP has a Generation to Load (GTL) relief obligation in response to a TLR issuance, SPP will utilize its market systems to calculate and send dispatch instructions to its Market Participants (MPs) necessary to achieve the relief.

3.3. SPP will follow procedures included in Market Protocols and its operating procedures to implement relief procedures, up to and including the point that emergency action is necessary. When SPP observes constraint loading that approaches the applicable SOL, it will communicate with the constraint owner to verify actual real-time flows and coordinate necessary actions to be taken. SPP will make a coordinated decision based on current and/or anticipated conditions to pursue relief by using the congestion management process.

4. For the Western Interconnection, SPP will utilize the Western Interconnection Congestion Management Methodology, including Unscheduled Flow Mitigation Procedure (UFMP).

5. SPP will monitor system frequency and its BAs' performance. If SPP determines that one or more of its BA areas are contributing to a frequency excursion, SPP will instruct the BA(s) to use all resources available, including load shedding, to comply with CPS and DCS requirements.

6. SPP will take or instruct whatever action is needed, including load shedding, to mitigate an energy emergency within the SPP RC Areas. SPP will provide assistance to other RCs experiencing an energy emergency as necessary.

7. SPP requires that any BA Area within its RC Areas that is experiencing an energy emergency, first use Operating Reserves available within its applicable Reserve Sharing Group (RSG). If the energy emergency still persists, SPP will issue an EEA on behalf of the deficient BA Area.

G. System Restoration

1. SPP is knowledgeable of the restoration plans of each of the Transmission Operators in its RC Areas and has a written copy of each plan in its possession. SPP verifies that the most current plans are on file on an annual basis. During system restoration, SPP monitors the restoration progress and coordinates any needed assistance.

2. SPP has regional restoration plans for the SPP RC Areas that provides coordination between individual restoration plans of each SPP Transmission Operator and that ensures reliability is maintained during system restoration events. The SPP RC Areas Regional Restoration Plans and NERC Reliability Standards require that the role of the SPP RC during system restoration is to facilitate this coordination. Furthermore, the SPP RC approves, communicates, and coordinates re-synchronization of system islands or synchronizing points such that a burden is not caused on adjacent TOP, BA, or RC Areas. SPP Communications Protocols delineate the processes for Emergency Communications.

3. SPP will disseminate information regarding restoration to neighboring RCs and BAs/ TOPs not immediately involved in restoration by posting pertinent information on the RCIS and/or via phone call. SPP will also use the NERC Hotline for updates to other RCs as needed.

H. Facility

SPP performs the RC function at each of its two Coordination Centers. Each Coordination Center has the necessary facilities for the SPP RCs to perform their responsibilities. Full functionality is provided with full backup of the systems, communications, data, and tools required for SPP to perform as the RC for its RC Members and Reliability Customers. Both primary and alternate sites are staffed and functionality 24x7.

1. SPP has redundant data communications between the two SPP sites, which are staffed 24x7 with working communications such as voice and data links between RC Member and Reliability Customer sites and SPP systems. SPP also employs a Voice-over-IP (VOIP) phone system that allows the phones to ring at both Coordination Center sites simultaneously. Cell phones are used as the alternate voice communication capability.

   SPP IT’s 24x7 desk and additional on-call staff provide support of the voice and data communications, hardware, and software, working with communication service companies as appropriate.

2. A satellite phone system is installed at both of SPP’s Coordination Centers as well as at all SPP RC Areas BA/TOP primary operations centers, for purposes of communicating during emergency conditions per SPP Communications Protocols. This system bypasses the Public Switched Telephone Network (PSTN) and can be used for point-to-point or broadcast (all-call) communications. The satellite service can also route a phone call to a land line, providing access to any operable wire or wireless phone.

3. SPP has detailed real-time monitoring capability of the SPP RC Areas and sufficient monitoring capability of surrounding RC Areas to ensure that potential or actual SOL or IROL exceedances are identified. SPP has monitoring systems that provide information that can be easily understood and interpreted, giving particular emphasis to alarm management and awareness systems, automated data transfers, synchronized information systems, over a redundant and highly reliable infrastructure. SPP monitors BES elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL exceedances within the SPP RC Areas. SPP monitors both real and reactive power system flows,

operating reserves, and the status of system elements that are or could be critical to SOLs and IROLs and system restoration requirements within the SPP RC Areas.

4. SPP utilizes two separate EMS clusters, an Authorized cluster and an Unauthorized cluster. If the Primary Location is lost, the primary EMS systems in the Alternate Location will automatically take over EMS functionality at the Alternate Location. As part of the EMS model upload and patching processes, all nodes of the primary and maintenance clusters are updated within the maintenance window.

5. SPP utilizes two separate ICCP clusters, a primary cluster and a back-up cluster (secondary ICCP). If the Primary Location is lost, the primary ICCP systems located in the Alternate Location will automatically take over primary ICCP functionality. As part of the ICCP model upload and patching processes, all nodes of the primary and maintenance clusters are updated within the maintenance window.

6. Per the applicable SPP RDS, SPP RC Members and Reliability Customers are required to send and receive near real-time data to both the primary and secondary systems concurrently as appropriate. Data from both systems are fed to the EMS providing an alternate data source for use when the primary source is failed for any reason.

I. Staffing

1. SPP 24x7 operations consists of four RC Operators and two Shift Engineers. The personnel is split between our primary and our alternate facilities with two RC Operators and one Shift Engineer at each location. These RC Operators and Shift Engineers are required to hold the NERC RC certification as well as being desk qualified at their position. SPP requires its RC Operators to complete yearly training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

2. SPP ensures that its RC Operators have a comprehensive understanding of the SPP RC Areas and required interaction with neighboring RCs. The SPP RC Operators have an extensive understanding of the RC Member and Reliability Customer systems within the SPP RC Areas such as staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities and restrictions. SPP makes year-round training opportunities available for the RC Operators, which includes the use of a Dispatcher Training Simulator (DTS) to provide realistic simulations of system emergencies described in the previous section.

   SPP creates training and performance support to ensure the SPP RC Operators understand the SPP region and the interface with neighboring regions. This includes opportunities for continuing education hours, including required emergency operations and simulation hours. This training includes familiarization with Member BAs/TOPs by including RC training on the RC Members' and Reliability Customers' operating guides, system configuration, and transmission facilities. Control Center evacuation training and performance-based exercises are provided annually through instructor-led courses. Operations personnel who have a role in the evacuation plan are required to participate in the evacuation training and performance-based exercise annually. In addition, SPP conducts regional system restoration drills annually.

SPP's training department documents all training for recordkeeping and reporting purposes. All information required by the NERC Continuing Education program is available in a variety of report formats.

3. An Officer of SPP has signed the NERC Reliability Coordinator Standards of Conduct on behalf of the SPP RC. Each SPP RC Operator is required to sign and receive training on the SPP Standard of Conduct annually. The SPP Standard of Conduct requires the signatory to maintain proper confidentiality procedures and processes. SPP is an independent organization with an independent Board of Directors. SPP's independence enables its staff to fully comply with both the NERC and SPP Standards of Conduct.

Appendix A – BAs and TOPs in SPP RC Areas

Balancing Authorities and Transmission Operators in the SPP Reliability Coordination Areas:

Entity	BA	TOP	East	West
Arlington Valley Power Cooperative (AVBA)	X			X
American Electric Power – West (AEP)		X	X	
Arizona Electric Power Cooperative/SW Transmission Coop (AEPC)		X		X
Black Hills Corporation (BHE)		X		X
City Utilities of Springfield (CUS)		X	X	
Colorado Springs Utilities (CSU)		X		X
Corn Belt Power Cooperative (CBPB)		X	X	
El Paso Electric (EPE)	X	X		X
Empire District Electric Company/Liberty Utilities (EDE)		X	X	
Farmington Electric Utility System (FEUS)		X		X
First Light Energy (BNBA)	X			X
Grand River Dam Authority (GRDA)		X	X	
New Harquahala Generating Company (HGBA)	X			X
City of Independence Power & Light Department, Missouri (INDP)		X	X	
Gridforce Energy Management (GRID)	X			X

Entity	BA	TOP	East	West
CORE Electric Cooperative (CORE)		X		X
ITC Great Plains (ITC)		X	X	
The Board of Public Utilities, Kansas City, Kansas (BPU)		X	X	
Kansas City Power and Light Company (KCPL)		X	X	
KCP&L Greater Missouri Operations Company (UCU)		X	X	
Lincoln Electric System (LES)		X	X	
Midwest Energy, Inc. (MIDW)		X	X	
Nebraska Public Power District (NPPD)		X	X	
Oklahoma Gas and Electric (OKGE)		X	X	
Omaha Public Power District (OPPD)		X	X	
Platte River Power Authority (PRPA)		X		X
Public Service of Colorado (PSCO)	X	X		X
Sunflower Electric Power Corporation (SEPC)		X	X	
Southwest Power Pool (SPP)	X		X	
Southwestern Power Administration (SPA)	X	X	X	
Southwestern Public Service Company (SPS)		X	X	
Tri-State G & T (TSGT) *		X	X	X
Tucson Electric Power (TEPC)	X	X		X
Western Areas Power Administration (WACM)	X	X		X
Western Areas Power Administration (WALC)	X	X		X
*Western Areas Power Administration (WAUE)		X	X	
Western Areas Power Administration (WAUW)	X	X		X
Western Farmers Electric Cooperative (WFEC)		X	X	
Westar Energy, Inc. (WRGS)		X	X	

**Eastern* <u>*and*</u> *Western Interconnections*

Midcontinent Independent System Operator

Regional Transmission Organization (RTO) Reliability Plan

December 26, 2024

Document Change History

Issue	Reason for Issue	Date
Version 0	Reformatted and updated MISO RTO Reliability Plan to meet the terms of NERC Operating Standards as approved by NERC.	11/3/05
Version 1	Removed LGEE and DEVI from Reliability Coordination Area. Added Southern Minnesota Municipal Power Agency to MISO tariff.	9/20/06
Version 2	Reflected Ameren's reconfiguration of their Balancing Areas from three into two.	2/2/07
Version 3	Reflects the de-certification of the Western Plains East Kansas (WPEK) Balancing Area	4/1/07
Version 4	Reflects the conception of the MISO Balancing Authority. To be effective with the start of MISO Balancing Authority operations.	11/14/07
Version 5	Reflects the addition of Duquesne Light Company (DLCO) local Balancing Authority into the MISO Balancing Authority. To be effective with the start of DLCO into MISO Balancing Authority and MISO Market.	05/07/08
Version 6	Reflects moving Missouri Public Service -Aquila Networks (MPS) Balancing Authority from MISO to SPP RC. To be effective with the move of MPS to SPP RC.	11/19/08
Version 7	Reflects Duquesne Light Company's (DLCO) decision to not become a Local Balancing Authority in MISO Balancing Authority Area. Reflects moving LES, NPPD, and OPPD from MISO RC Area to SPP RC Area. To be effective with the move of LES, NPPD, and OPPD to SPP RC. Reflects starting to provide Cleveland Public Power Reliability Coordination services to be effective with the start of the service.	01/31/09
Version 8	Reflects MidAmerican Energy Company (MEC) and Muscatine Power and Water (MPW) changing from Balancing Authorities (BAs) to Local Balancing Authorities (LBAs) and being incorporated into Midwest ISO Balancing Authority Area. Midwest ISO Reliability Coordination Area boundaries are not changing with this version. This version becomes effective with the incorporation of MEC and MPW LBAs into Midwest ISO BA.	06/23/09
Version 9	Reflects the addition of Cedar Falls Utilities (CFU) and other miscellaneous updates	9/23/09
Version 10	Reflects Dairyland Power Cooperative (DPC) changing from Balancing Authority (BA) to Local Balancing Authority (LBA)	1/8/10

	and being incorporated into Midwest ISO Balancing Authority Area. Midwest ISO Reliability Coordination Area boundaries are not changing with this version. This version becomes effective with the incorporation of DPC LBA into Midwest ISO BA.	
Version 11	Reflects Big Rivers Electric Corporation (BREC) Balancing Area moving from TVA RC to Midwest ISO RC. Also reflects BREC changing from Balancing Authority (BA) to Local Balancing Authority (LBA) and being incorporated into Midwest ISO BA Area. Note that depending on state regulatory approval, BREC BA integration into Midwest ISO BA may occur subsequent to Midwest ISO becoming BREC's RC. This version becomes effective with the BREC BA moving into Midwest ISO RC Area.	5/10/10
Version 12	Reflects First Energy LBA exiting the Midwest ISO BA and the Midwest ISO Reliability Footprint, scheduled for June 1, 2011 and Cleveland Public Power exiting its Reliability Coordination Services Agreement with the Midwest ISO, scheduled for June 1, 2011	2/9/11
Version 13	Reflects Missouri River Energy Services becoming a Transmission Owning member of the Midwest ISO and Ohio Valley Electric Corporation and Department of Energy taking Reliability Coordination Services from Midwest ISO scheduled for June 1, 2011.	5/4/11
Version 14	Reflects Lansing Board of Water and Light taking Reliability Coordination Services from MISO. This version becomes effective when LBWL begins RC Services with MISO (currently scheduled for September 1, 2011).	8/11/2011
Version 15	Reflects Duke Energy Ohio and Kentucky LBA exiting the MISO BA and the MISO Reliability Footprint, scheduled for January 1, 2012. Duke Energy Indiana remains in the MISO BA and MISO Reliability Footprint	11/15/2011
Version 16	Reflects Entergy taking Reliability Coordination Services from MISO. This version becomes effective when Entergy begins RC services with MISO (currently scheduled for November 19, 2012).	3/2/12
Version 17	Reflects Entergy (EES) Balancing Area changing from a Balancing Authority (BA) to Local Balancing Authority (LBA) and being incorporated into MISO BA Area (currently scheduled for December 19, 2013). Also included in this revision are multiple Balancing Authorities that are expected to join the MISO RC area on June 1, 2013 and subsequently the MISO BA area on December 19.2013. The BAs included are City of Conway (CWAY), Brazos Electric Corporation (BRAZ), CLECO, Lafayette Utility System (LAFA), Louisiana Energy and Power Authority (LEPA), Louisiana Generating (LAGN), Plum Point Energy Associates (PLUM), City of Osceola (OMLP), City of West Memphis (WMU), City of North Little Rock (NLR), City of Benton (BUBA), Union	1/1/13

	Power Partners (PUPP), City of Ruston (DERS), South Mississippi Electric (SME), The listing of BAs above is based on BAs defined on 1/1/13. The BAs are also evaluating the BA boundaries and may determine to change their BA boundaries. This version becomes effective with the BAs listed, pending regulatory approvals, Regional Entity/NERC certifications) moving into MISO RC Area and subsequently the MISO BA Area.	
Version 18	Reflects the Eagan Control Center move from St. Paul, scheduled for December, 2013 and the Midwest ISO name change to Midcontinent ISO, already completed.	11/20/2013
Version 19	Reflects a clean-up from December 19, 2013 South Region Integration (removing dissolved BAs, removing footnotes, etc.), adding AECC and City of Ames as a Transmission Owners, MIUP as a new LBA, and adding City of Alexandria and Consumers Energy as Reliability Services Customers.	5/8/2014
Version 20	Reflects the move of the Integrated System (WAPA, Basin Electric, and Heartland Consumers Power District) and Corn Belt Power Cooperative to the SPP Reliability Coordination Footprint scheduled for June 1, 2015. Also reflects additional Transmission Owners in MISO of Rochester Public Utilities, City of Alexandria (LA), City of Marshall (MN), already completed or scheduled in 2015, and the addition of Entergy Mississippi as a Local Balancing Area in the MISO Balancing Authority Area. Added Little Rock, AR as a MISO Control Center scheduled for June, 2015.	3/20/2015
Version 21	Local Balancing Area Entergy Mississippi Abbreviation change from EMI to EMBA, Pioneer Transmission becoming a Transmission Owner, and AEP becoming a MISO TOP	5/8/2018
Version 22	Ohio Valley Electric Corp transferring from the MISO Reliability Footprint to PJM on 12/1/2018 and updating the South Mississippi Electric Power Association to Cooperative Energy. Clean up of directives to operating instructions and SOL/IROL violations to exceedances.	12/1/2018
Version 23	Henderson Municipal Power & Light entering MISO as an LBA and Transmission Owner and AEP Indiana Michigan Transmission Company, Inc. entering as a Transmission Owner.	3/1/2019
Version 24	GridLiance Heartland BA and LBA transition to MISO RC from TVA RC. GridLiance Heartland LBA transitions into MISO BA.	3/1/2020
Version 25	Update to Current Day analysis language	9/1/2019
Version 26	Updated GridLiance transition to March 1, 2020	3/1/2020
Version 27	Updated Republic Transmission as MISO TO on June 1,2020	6/1/2020
Version 28	Reflects GridLiance Heartland (GLH & GLHB) LBA and TOP functions transitioning to Lonestar Transmission (LST) on	9/1/2022

	September 1, 2022. Lonestar Transmission will operate as an LBA and TOP within the MISO BA and the MISO reliability Footprint.	
Version 29	Reflects Missouri Joint Municipal Electric Utility Commission joining MISO as a TO.	12/8/2022
Version 30	Reflects City Water and Light Plant of the City of Jonesboro joining MISO as a TO.	12/1/2023
Version 31	Reflects Louisiana Generation & Transmission joining MISO as an LBA (Appendix B). Reflects 1803 Electric Cooperative and Citizen Electric Corporation joining MISO as a TO (Appendix A). Reflects Nexus Line, LLC and Sikeston Board of Municipal Utilities receiving MISO RC services (Appendix A). Re-alphabetized Appendices A and B.	12/26/2024

Table of Contents

Introduction

The North American Electric Reliability Corporation (NERC) requires every Region, sub-region, or interregional coordinating group to establish a Reliability Coordinator (RC) to provide the reliability assessment and emergency operations coordination for the Balancing Authorities (BAs) and Transmission Operators (TOPs) within the Regions and across the Regional boundaries.

The Midcontinent Independent System Operator (MISO) serves as the RC for its members, under coordination agreements, and under RC agreements. The MISO RC has certain defined responsibilities and directs the reliable operation of Bulk Power System which is, in general, 100 kV facilities and higher. The MISO RC functions associated with the reliability of the Bulk Power System include review and approval of planned facility transmission line outages[1] & generation outages[2] based upon current and projected system conditions, monitoring of real time loading information and calculating post-contingent loadings on the transmission system, administering loading relief procedures, re-dispatch of generation, and ordering curtailment of transactions and/or load. The MISO RC functions associated with power supply reliability entails monitoring BA performance and ordering the BAs to take actions, including load curtailment and increasing/decreasing generation in situations where an imbalance between generation and load places the system in jeopardy. The MISO reliability procedures and policies are consistent with NERC Standards.[3] MISO operates in multiple NERC Regions and recognizes each Region's policies and standards. Where there are conflicts in the Regional policies and standards, MISO works with the Regions and members on resolving those conflicts. MISO also provides RC Services for non-market members via Module F.

This document is the Reliability Plan for the MISO RC and is posted at https://www.nerc.com/comm/OC/Pages/ORS/Reliability-Plans.aspx. This version supersedes the previous version.

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[1] For those Non-market members within MRO, MISO reviews all planned facility transmission line outages for these entities, notifies the entities of possible conflicts or system conditions that would warrant reconsideration of these planned outages, and works with the entities – along with MISO members - to resolve any issues. Further revisions of NERC Standards may render this distinction obsolete.

[2] MISO discusses and coordinates pending generation maintenance outages to the extent possible, as MISO has authority to deny generation maintenance outages only in cases where such outages would place MISO in an emergency situation.

[3] While the MISO Reliability Coordination Plan describes MISO's general practices of providing RC services and in some circumstances MISO RC's endeavor to use best practices beyond what is required by the NERC Reliability Standards , Nothing in this plan shall require MISO RC to go beyond what is required by the NERC Reliability Standards with regard to meeting NERC compliance requirements.

A. Responsibilities – Authorization

1. Reliable Operations - MISO has certain defined responsibilities for the reliable operation of the Bulk Power System within the its RC Area in accordance with NERC Standards, Regional policies and standards, as well as the governing documents listed in Appendix C of this document. The MISO RC Area is composed of the Transmission Owners' Areas listed in Appendix A.

   1.1 The MISO RC has a Wide Area view of its RC Area and neighboring areas that have an impact on MISO's Area. The MISO RC and MISO BA have the operating tools, processes and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and during real-time conditions per the NERC Standards and Regional standards, as well as the governing documents listed in Appendix C of this document.

   The MISO RC operating tools, which provide the Wide Area View, are listed in Section I.

   1.2 The MISO RC has clear decision-making authority to act and to direct actions to be taken by its members and non-MISO members within its Reliability Coordination Area to preserve the integrity and reliability of the Bulk Power System.

   1.3 The MISO RC and the MISO BA have not delegated any of its RC or BA responsibilities.

2. Independence - MISO does and will act first and foremost in the best interest of the reliability for its RC Area and the Eastern Interconnection before that of any other entity. This expectation is clearly identified in the governing documents listed in Appendix C and in the job descriptions of the MISO personnel acting in the role of RC or BA.

3. MISO RC Operating Instructions Compliance - Per the governing documents in Appendix C, the BAs, TOPs and other operating entities in the MISO RC Area shall carry out required emergency actions as given in operating instructions by the MISO RC, including the shedding of firm load if required, except in cases involving endangerment to the safety of employees or the public. In those cases, members of the MISO RC Area must immediately inform the MISO RC of the inability to perform the operating instruction.

B. Responsibilities – Delegation of Tasks

1. The MISO RC and the MISO BA have not delegated any RC or BA tasks. Local Balancing Authorities (LBAs) within the MISO Balancing Area are responsible for and will perform tasks per the MISO BA/LBA Coordinated Functional Registration with NERC and the MISO Amended BA Agreement.

C. Common Tasks for Next-Day and Current-Day Operations

This section documents how the MISO conducts current-day and next-day reliability analysis for its Reliability Coordination Area.

1. Determination of Interconnection Reliability Operating Limits (IROLs) – The MISO RC determines IROLs based on local, regional and inter-regional studies including seasonal assessments and ad hoc studies. As required, the voltage stability IROLs are calculated in the next day security analysis and limits are conveyed to neighboring RCs and TOPs in the MISO RC Area via the next day security analysis report. The IROL limits are also reviewed each weekday morning during reliability conference calls.

   During the operating day, real time voltage stability analyses are performed to provide updated IROLs, based on the latest system conditions, to the MISO RC. Significant IROL changes are communicated to impacted TOPs in the MISO RC Area and neighboring RCs by email and phone as necessary. Standing IROL interfaces are highlighted in bold in MISO operator displays to differentiate them from System Operating Limit (SOL) flowgates.

   During real time operations, the MISO RC recognizes that a new IROL limit can be created during multiple, normally non-critical outage conditions and the MISO RC determines additional IROLs real-time. To determine these additional IROLs, the MISO RC utilizes a state estimator and real time contingency analysis to analyze real-time and first contingency conditions. These contingency analyses are normally repeated every one to two minutes. In the event a first contingency would cause a post-contingency flow of 125% of the emergency rating, it is automatically assumed the SOL is now an IROL unless there are studies or system knowledge that the SOL is not an IROL. An example of an SOL greater than 125% that would not be considered an IROL is a radial system that would not result in uncontrolled cascading or collapse should the monitored element(s) trip. Contingency analysis results indicating an unsolved contingency which is confirmed to be valid is also considered to be an IROL.

2. Operation to prevent the likelihood of a SOL or IROL exceedance in another area of the Interconnection and operation when there is a difference in limits - The MISO RC, through agreements with its RC neighbors, coordinates operations to prevent the likelihood of an SOL or IROL exceedance in another area. These agreements include data exchange, Available Transfer Capability coordination, and Outage Coordination and are listed in Section H.

   TOPs in the MISO RC Area are required to follow operating instructions provided by the MISO RC per NERC Standards and operate to NERC Standards to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordination Area will result in an SOL or IROL exceedance in another area of the Interconnection.

   When there is a difference in derived limits, MISO RC utilizes the most conservative limit until the difference is resolved.

3. Operation under known and studied conditions and re-posturing without delay and no longer than 30 minutes - The MISO RC ensures that entities within its RC Area always operate under known and studied conditions and that they return their systems to a secure operating state following

contingency events within approved timelines, regardless of the number of contingency events that occur or the status of their monitoring, operating and analysis tools. The MISO RC also ensures its BAs and TOPs re-posture the system to within all IROLs following contingencies within T*v* or 30 minutes, whichever is shorter.

On a daily basis, the MISO RC conducts next-day security analysis utilizing planned outages, forecasted loads, generation commitment, and expected net interchange. The analyses include contingency analysis, voltage stability analysis on key interfaces and a review of reactive reserves for defined areas when appropriate. These analyses model peak conditions for the day and are conducted utilizing first contingency (N-1) analysis. Results and mitigation are documented in the Next-Day Security Analysis Report and distributed to MISO Reliability staff. The Next-Day Security Analysis Report is also posted on the MISO Extranet secure website for distribution from this secure website for TOPs and BAs in the MISO Reliability Coordination Area and neighbors to view and download. Mitigation plans are formed as needed for potential exceedances determined in the next day security analysis. Mitigation is of the form of additional unit commitment or may be documented in an operating guide to be utilized by the MISO RC and TOP.

MISO performs Current Day Security Analysis studies as needed throughout the day. Voltage Stability analyses are also performed continuously and on demand as system conditions warrant for each voltage stability flowgate. Results from Voltage stability analysis are available to MISO Reliability staff and also posted to the MISO Extranet for the TOPs and BAs in the MISO Reliability Coordination Area and neighbors.

The MISO Daily Reliability Coordination Report is also posted on the MISO Extranet secure web site for TOPs and BAs in the MISO Reliability Coordination Area and neighbors to view and download. The MISO Daily Reliability Coordination Report includes significant generation outages, significant line outages, projected constraints, voltage security assessment results, reactive reserves for defined areas when appropriate, TLR summary from the past 24 hours, and forecasted weather conditions. The MISO Daily Reliability Coordination Report is reviewed each weekday morning with TOPs, the MISO BA, Balancing Areas in the MISO Reliability Coordination Area, and neighboring RCs where expected system conditions for the day are discussed, along with action required to mitigate any abnormal conditions. Additional conference calls are conducted with the same group when conditions warrant.

4. Communicating SOLs and IROLs to Transmission Service providers within RC Area – MISO communicates IROLs within its wide-area view and provides updates to IROLs as described above via reports, morning conference calls, and real-time via voice and messaging. Standing IROLs are documented and communicated via operating guides. In general, SOLs are in the form of thermal equipment limits and are provided by Transmission Owners to MISO. If transmission service is sold on the IROL or SOL Flowgate, an adjustment is made to the AFC to account for the reservation.

5. MISO RC and BA process for issuing operating instructions - MISO has implemented a communication protocol for the issuing/receiving of operating instructions. The MISO RC and/or MISO BA issues operating instructions in a clear, concise and definitive manner. The MISO RC and/or MISO BA ensures that the person receiving the operating instruction repeats the information back correctly, and acknowledges the response as correct or repeats the original statement again to

resolve any misunderstandings. MISO's process for issuing operating instructions is documented in the "Communications Protocol For Operating Instructions" procedure.

D. Next-Day Operations

This section documents how the MISO conducts next-day reliability analysis for its Reliability Coordination Area.

1. Reliability Analysis and System Studies - The MISO RC conducts next-day reliability analyses for its Area to ensure that the Bulk Power System can be operated reliably in normal and post contingency conditions.

   On a daily basis, the MISO RC conducts next-day security analysis utilizing known outages, forecasted loads, generation commitment and dispatch, and expected net interchange. All facilities 100 kV and above and some non-BES facilities in the MISO RC Area and first tier Balancing Areas are monitored for all contingency cases and the base case. Base case flows on all monitored facilities are compared against the normal rating. Post-contingent flows for all monitored facilities are compared against their emergency rating for all contingencies. Voltage and transient stability analysis is conducted on key critical interfaces to determine a flow limit. Reactive reserves for specific areas are reviewed to ensure they are above necessary levels.

   Mitigation plans are formed as needed for potential violations determined in the next day security analysis. Mitigation is of the form of additional unit commitment, restriction on unit output, or may be documented in an operating guide to be utilized by the MISO RC and TOPs.

   1.1 Parallel Flows – The MISO RC monitors parallel flows to ensure that its Reliability Coordination Area does not burden another Reliability Coordination Area. To ensure that the impact of parallel flows is considered in the next day security analysis, all first tier BA Areas and key second and third tier BA Areas are modeled in detail and updated in the analysis each day. This includes updating their unit status, transmission outages, load forecast, interchange and generation dispatch.

2. Information Sharing – BAs, Generation Operators and TOPs in the MISO Reliability Coordination Area and neighboring RCs provide to the MISO RC all information required for system studies, such as critical facility status, load, generation, and Operating Reserve projections via the SDX. The entities in the MISO Reliability Coordination Area provide generation and transmission facility statuses to the MISO outage scheduling application per MISO outage scheduling requirements. MISO Reliability Coordination Area load forecast is provided in the SDX. MISO BA load is determined by MISO load forecasting tools. Known interchange transactions are provided as NERC E-Tags. MISO obtains the equivalent information for entities outside the MISO Reliability Coordination Area from the SDX and NERC E-Tags.

3. Sharing of Study Results - When conditions warrant or upon request, the MISO RC shares the results of its system studies with the entities within its Reliability Coordination Area or with other RCs. Study results for the next day typically are available no later than 16:00 Eastern Standard Time, unless circumstances warrant otherwise.

   Next-Day Security Analysis Report is distributed to MISO Reliability staff. The Next-Day Security Analysis Report is also posted on the MISO Extranet secure website for distribution to TOPs and BAs in the MISO Reliability Coordination Area and neighboring RCs to view and download. Any reliability entity that is subject to the NERC Data Confidentiality Agreement may access the Next-Day Security Analysis Report, with approved access, via the MISO Extranet secure web site.

The MISO RC has procedures indicating when it will initiate a conference call or other appropriate communications to address the results of its reliability analyses. The MISO RC hosts a conference call each business day that is normally utilized for this purpose.

E. Current-Day Operations

This section documents how the MISO conducts current-day reliability analysis for its Reliability Coordination Area.

1. The process MISO RC uses to monitor all Bulk Power System facilities, including sub-transmission information as needed, within the MISO Reliability Coordination Area and adjacent areas as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the MISO RC is able to determine any potential SOL and IROL exceedances within its Reliability Coordination Area is as follows:

   MISO RC utilizes a state estimator and real-time contingency analysis as its primary tool to monitor facilities. The state estimator model includes all facilities 100 kV and above in the MISO Reliability Coordination Area and extensive representation of 69 kV facilities. The model also has extensive representation of neighboring facilities in order to provide an effective wide-area view. This model is updated quarterly and may be updated on demand when deemed necessary.

   Real Time Contingency Analysis (RTCA) is performed on over 10,000 contingencies utilizing the state estimator model normally at least every five minutes. Contingencies include all MISO Reliability Coordination Area equipment 100 kV and above, some non-BES equipment, and neighboring contingencies that would impact MISO Reliability Coordination Area facilities.

   MISO utilizes a Real-Time Line Outage Distribution Factor (RTLODF) Tool to monitor selected PTDF and OTDF flowgates to provide a backup to RTCA monitoring. Post-contingent loading on OTDF flowgates is calculated using SCADA data and LODFs automatically updated from a topology processor that does not rely on the state estimator solution.

   SCADA alarming is utilized to alert the MISO RC of any actual low or high voltages or facilities loaded beyond their normal or emergency limits.

   In addition to the above applications, MISO utilizes a dynamically updated transmission overview display to maintain a wide area view. Transmission facilities 230 kV and above are depicted on the overview with flows (MW and MVAR). This display provides indication of facilities out of service, high and low voltage warning and alarming, and facilities loaded to 90% and 100% of ratings. For more detailed monitoring, dynamically updated Balancing Area wide displays are used to view facilities 100 kV and above, including flows (MW and MVAR), voltages, generator outputs, and facilities out of service. Finally, bus level one-line diagrams are utilized for station level information.

   1.1. The MISO RC notifies neighboring RCs of operational concerns (e.g. declining voltages, excessive reactive flows, or an IROL exceedance) that it identifies within the neighboring Reliability Coordination Area via direct phone calls, conference calls, NERC hotline calls, and/or RCIS messages. The MISO RC has documented seams agreements with neighboring RCs that are listed in Section H. MISO RC directs action to provide emergency assistance to all Reliability Coordination neighbors, during declared emergencies, which is required to mitigate the operational concern to the extent that the same entities are taking in kind steps and the assistance would be effective.

2. The MISO RC maintains awareness of the status of all current critical facilities whose failure, degradation or disconnection could result in an SOL or IROL exceedance within its Reliability Coordination Area via State Estimator, RTCA, SCADA alarming, and transmission displays. The MISO RC is aware of the status of any facilities that may be required to assist Reliability Coordination Area restoration objectives via these same displays and tools.

3. The MISO RC is continuously aware of conditions within its Reliability Coordination Area includes this information in its reliability assessments via automatic updates to the state estimator, Flowgate Monitoring Tool, and transmission displays. The MISO RC monitors its MISO Reliability Coordination Area parameters, including the following:

    3.1. Current status of Bulk Power System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems and system loading are monitored by state estimator, RTCA, SCADA Alarming, Flowgate Monitoring Tool, and transmission displays. Balancing Areas are required to report to MISO RC when Automatic Voltage Regulators are not in-service. TOPs are required to report to the MISO RC when Special Protection Systems change status.

    3.2. Current pre-CONTINGENCY element conditions (voltage, thermal, or stability) are monitored by state estimator, SCADA Alarming, Flowgate Monitoring Tool, and transmission displays.

    3.3. Current post-CONTINGENCY element conditions (voltage, thermal, or stability) are monitored by RTCA, Flowgate Monitoring Tool, and transmission displays.

    3.4. System real reserves are monitored versus required per Balancing Area in the Market Monitoring Tool. Reactive reserves versus required are monitored via monitoring adequacy of calculated post-contingent steady state voltages versus voltage limits, voltage stability interfaces against limits, and reactive reserves versus required for defined zones.

    3.5. Capacity and energy adequacy conditions via monitoring reserve requirements and regional reporting.

    3.6. Current ACE for all Balancing Areas is displayed in a trend graph to MISO RC. When ACE exceeds L_{10}, graph changes colors and alerts operator of magnitude of ACE and duration ACE has exceeded L_{10} .

    3.7. Current local procedures, such as operating guides, monitored via discussions with local TOP and statuses of their use are logged in the MISO RC log. TLR procedures in effect are monitored via the NERC Interchange Distribution Calculator.

    3.8. Planned generation dispatches for MISO market area are provided to the MISO RC in the form of the unit commitment plan. For the non-market area, generation outages are reported to MISO via the MISO Outage Scheduler application.

    3.9. Planned transmission or generation outages are reported to MISO via the MISO Outage Scheduler application.

3.10. Contingency Events are monitored by state estimator, RTCA, SCADA Alarming, Flowgate Monitoring Tool, and transmission displays. TOPs and BAs are required to report Contingency Events to MISO RC.

4. The MISO RC monitors Bulk Power System parameters that may have significant impacts upon its Reliability Coordination Area and neighboring Reliability Coordination areas with respect to:

4.1. The MISO RC maintains awareness of all Interchange Transactions that wheel-through, source, or sink in its Reliability Coordination via NERC E-tags and NERC IDC displays. Interchange Transaction information is made available to all RCs via NERC E-tags.

4.2. The MISO RC, in concert with the Balancing and Interchange Authorities within its Reliability Coordination Area, evaluates and assesses any additional Interchange Transactions that would exceed IROL or SOLs by using the NERC IDC as a look-ahead tool. As flows approach their IROL or SOLs, the MISO RC evaluates the incremental loading next-hour transactions would have on the SOLs or IROLs and determines if action needs to be taken to prevent an SOL or IROL exceedance. The MISO RC has the authority to direct all actions necessary and may utilize all resources to address a potential or actual IROL exceedance up to and including load shedding.

4.3. The MISO RC and MISO BA monitors Balancing Area Operating Reserves versus required to ensure the required amount of Operating Reserves are provided and available as required to meet NERC Control Performance Standards via the Market Monitoring Tool. The MISO RC and the MISO BA are alerted if reserves fall below required. If necessary, the MISO RC will direct the Balancing Area to replenish reserves including obtaining assistance from neighbors as needed.

4.4. The MISO RC identifies the cause of potential or actual SOL or IROL exceedances via analysis of state estimator results, RTCA results, SCADA Alarming of outages, Flowgate Monitoring Tool results, transmission displays of changes, and Interchange Transaction impacts. The MISO RC will initiate control actions including transmission switching, generation redispatch, and/or emergency procedures to relieve the potential or actual IROL exceedance without delay, and no longer than 30 minutes. The MISO RC is authorized to direct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance. The MISO RC will not rely solely on NERC TLR to mitigate an IROL exceedance.

4.5. The MISO RC communicates start and end times for time error corrections to all Balancing Areas within its Reliability Coordination Area via its messaging system. The MISO RC communicates Geo-Magnetic Disturbance forecast information to BAs, TOPs, and Generation Operators via its messaging system. MISO RC will assist in development of any required response plan and will establish an Emergency Operating Guide as needed or move to conservative operating mode to mitigate impacts as needed.

4.6. The MISO RC (Carmel, Eagan, and Little Rock locations) participates in NERC Hotline discussions, assist in the assessment of reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. The MISO RC will disseminate this information via text messaging, individual phone calls, or blast calls within its area as appropriate.

4.7. The MISO RC monitors system frequency via trend graph. The graph visually alerts the MISO RC when frequency falls below 59.95 Hz or is greater than 60.05 Hz. MISO BA monitors its ACE, while the MISO RC monitors each Balancing Area's ACE via trend graph within the Reliability Coordination Area. Both the MISO BA and the MISO RC receive a visual indication when ACE exceeds L_{10} and/or BAAL. When necessary, MISO RC directs Balancing Areas with ACEs larger than L_{10} to return within L_{10}, and directs Balancing Areas to return to within BAAL. The MISO RC will direct BAs to utilize all resources, including firm load shedding, as necessary to relieve an emergency condition.

4.8. The MISO RC coordinates with other RCs and its BAs, Generation Operators, and TOPs, as needed, on the development and implementation of action plans and operating guides to mitigate potential or actual SOL or IROL exceedances, or CPS1, BAAL, or Reportable Balancing Contingency Event criteria.. The MISO RC coordinates pending generation and transmission maintenance outages with other RCs and its BAs, Generation Operators, and TOPs, as needed and within code of conduct requirements, real time via telephone and next-day, per the MISO outage scheduling process.

4.9. The MISO RC will assist its BA Areas in arranging for assistance from neighboring RCs or BA Areas via the Energy Emergency Alert (EEA) notification process and will conference parties together as appropriate.

4.10. The MISO RC monitors Balancing Areas' ACEs to identify the sources of large ACEs that may be contributing to frequency, time error, or inadvertent interchange and directs corrective actions with the appropriate BAs per 4.7 above.

4.11. The TOPs within MISO Reliability Area inform MISO of all changes in status of Special Protection Systems (SPS) including any degradation or potential failure to operate as expected by the TOP. The MISO RC factors these SPS changes into its reliability analyses.

5. The MISO RC issues alerts, as appropriate, to all its Balancing Areas and TOPs via dedicated text messaging, individual phone calls, or blast calls when it foresees a transmission problem (such as an SOL or IROL exceedance, loss of reactive reserves, etc.) within its Reliability Area that requires notification. The MISO RC issues alerts, as appropriate, to all RCs via the Reliability Coordinator Information System when it foresees a transmission problem (such as an SOL or IROL exceedance, loss of reactive reserves, etc.) within its Reliability Area that requires notification.

6. The MISO RC confirms reliability assessment results via analyzing results of state estimator/RTCA, and discussions with local TOPs and neighboring RCs. The MISO RC identifies options to mitigate potential or actual SOL or IROL exceedances via examining existing operating guides, system knowledge, and power flow analysis to identify and implement only those actions as necessary as to always act in the best interests of the interconnection.

F. Emergency Operations

1. The MISO RC utilizes the MISO Emergency Operating Procedures, posted on the www.misoenergy.org site, to return the transmission system to within the IROL as soon as possible, but no longer than 30 minutes. This procedure includes the actions (e.g. reconfiguration, re-dispatch or load shedding) the MISO RC will direct until relief is achieved.

2. The MISO RC utilizes the MISO Emergency Operating Procedures when it deems that an IROL exceedance are imminent. The MISO Emergency Operating Procedures documents the processes and procedures the MISO RC follows when directing its BAs and TOPs to re-dispatch generation, reconfigure transmission, manage Interchange Transactions, or reduce system demand to mitigate the IROL exceedance, to return the system to a reliable state. The MISO RC coordinates its alert and emergency procedures with other RCs via seam coordination agreements listed in Section H.

3. The MISO RC takes or directs action in the event the loading of transmission facilities progresses to or is projected to progress to an SOL or IROL exceedance.

   3.1 The MISO RC directs reconfiguration and/or re-dispatches within its market area as needed to prevent or relieve SOL or IROL exceedances. In the non-market area of MISO Reliability Coordination Area, the MISO RC will direct reconfiguration and re-dispatch to resolve IROL exceedances. The MISO RC will not rely on or wait for NERC TLR to relieve IROL exceedances. The MISO RC may implement NERC TLR if doing so will provide additional relief.

   3.2 The MISO RC utilizes market-to-market re-dispatch for its market area for reciprocally coordinated flowgates per the Congestion Management Process posted on the www.misoenergy.org site and filed with FERC.

   3.3 The MISO RC acknowledges provisions of the NERC TLR and communicates curtailment information as appropriate to impacted Balancing Authorities.

   3.4 The MISO RC will initiate re-configuration, re-dispatch for market areas, and NERC TLR reductions to relieve overloaded facilities as necessary. The MISO RC will not rely on NERC TLR as an emergency action.

4. The MISO RC utilizes the MISO Emergency Operating Procedures to mitigate an energy emergency within its Reliability Coordination Area. The MISO RC will provide assistance to other RCs per its seams agreements listed in Section H.

5. The MISO RC utilizes the MISO Emergency Operating Procedures when it is experiencing a potential or actual Energy Emergency within any BA, Reserve-Sharing Group, or Load-Serving Entity within its Reliability Coordination Area. The MISO Emergency Operating Procedures document the processes and procedures the MISO RC uses to mitigate the emergency condition, including a request for emergency assistance if required.

G. System Restoration

1. Knowledge of members' Restoration Plans - The MISO RC is aware of each member's Restoration Plan and has a written copy of each plan. The MISO has the plans and procedures of every member, which are listed in Appendix A.

   During system restoration, MISO RC monitors restoration progress and acts to coordinate any needed assistance.

2. MISO Restoration Plan - The MISO Restoration Plan includes all BAs and TOPs in its Reliability Coordination Areas. MISO RC takes action to restore normal operations once an operating emergency has been mitigated in accordance with its Restoration Plan. This Restoration Plan is drilled at least annually.

3. Dissemination of Information - The MISO RC serves as the primary contact for disseminating information regarding restoration to neighboring RCs and members not immediately involved in restoration.

   The MISO RC approves, communicates and coordinates the re-synchronizing of major system islands or synchronizing points so as not to cause a burden on member or adjacent Reliability Coordination Areas.

H. Adjacent RC Agreements and Data Sharing

1. Coordination Agreements:

   - MISO and PJM have a Joint Operation Agreement
   - MISO and TVA have a RC Coordination and Notification Plan
   - MISO and IESO have a Coordination Agreement.
   - MISO and SPP have a Joint Operating Agreement.
   - MISO and Southeastern RC have a RC Coordination and Notification Plan.
   - MISO and SaskPower have a RC to RC Agreement.

2. Data Sharing - The MISO RC determines the data requirements to support its reliability coordination tasks and requests such data from members or adjacent RCs. The MISO RC provides for data exchange with members and adjacent RCs, TOPs and BAs via a secure network. MISO Reliability Coordination Area members provide data to MISO via ICCP. MISO RC provides data to entities outside MISO via direct links and ISN.

I. Facility

MISO performs the RC function at the MISO Headquarters in Carmel, Indiana along with the MISO offices in Eagan, Minnesota, and Little Rock, Arkansas. The Carmel, Eagan, and Little Rock offices have the necessary voice and data communication links to appropriate entities within their Reliability Coordination Area for the MISO RC to perform their responsibilities. These communication facilities are staffed and available to act in addressing a real-time emergency condition.

1. Adequate Communication Links - The MISO RC maintains satellite phones, Voice Over IP phones which run across the dedicated MISO WAN, cell phones, and redundant, diversely routed telecommunications circuits. Additionally, there are also video links between MISO Carmel Control Room and the MISO Eagan and Little Rock Control Rooms.

2. Multi-directional Capabilities – The MISO RC has multi-directional communications capabilities with its members, and with neighboring RCs, for both voice and data exchange to meet reliability needs of the Interconnection.

3. Real-time Monitoring - The MISO RC has detailed real-time monitoring capability of its Reliability Coordination Area and all first tier companies surrounding the MISO Reliability Coordination Area to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit exceedances are identified.

   3.1 The MISO RC monitors Bulk Power System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL exceedances within its Reliability Coordination Area. The MISO RC monitors both real and reactive power system flows, and operating reserves, and the status of the Bulk Power System elements that are, or could be, critical to SOLs and IROLs and system restoration requirements within its Reliability Coordination Area.

4. Study and Analysis Tools

   4.1 The MISO RC has adequate analysis tools, including state estimation, pre-and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays. The MISO RC has detailed monitoring capability of the MISO Reliability Area and sufficient monitoring capability of the surrounding Reliability Areas to ensure potential reliability issues are identified. The MISO RC continuously monitors key transmission facilities in its area in conjunction with the Members monitoring of local facilities and issues.

   The MISO RC ensures that SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable. The MISO RC has backup facilities that shall be exercised if the main monitoring system is unavailable.

   The systems utilized by the MISO RC are:

- State Estimator and Contingency Analysis
- Market Monitoring Tool
- Status and Analog Alarming
- Overview Displays of MISO Transmission System via Wallboard
- One line diagrams for entire MISO Transmission System
- Transmission Delta Flow Tool
- Flowgate Monitoring Tool
- Generation Monitoring Tool

The MISO RC utilizes these tools, which provide information that is easily understood and interpreted by the MISO RC operating personnel. The alarm management is designed to classify alarms in priority for heightened awareness of critical alarms.

4.2 The MISO RC controls its RC analysis tools, including approvals for planned maintenance. The MISO RC has procedures in place to mitigate the effects of analysis tool outages.

J. Staffing

1. Staff Adequately Trained and NERC Certified - MISO maintains trained RCs, BAOs, and a Shift Manager on duty at all times, as well shift Reliability Engineers. The MISO RC and MISO BA staff all operating positions that meet following criteria with personnel that are NERC certified for the applicable functions:

   - Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Power System.

   - Positions directly responsible for complying with NERC Standards.

   The MISO RC and MISO BA operating personnel each complete a minimum of 40 hours per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operation personnel.

2. Comprehensive Understanding - The MISO RC operating personnel have an extensive understanding of the BAs and TOPs within the MISO Reliability Coordination Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.

   The MISO RC operating personnel place particular attention on SOLs and IROLs and inter-tie facility limits. The MISO ensures protocols are in place to allow MISO RC operating personnel to have the best available information at all times.

   MISO's System Operator Training process describes the process by which System Operations personnel are trained to perform their duties, both at entry level and in continuous training status. MISO also uses the Operator Training Manual to establish training and documentation requirements for System Operators in the form of position specific curricula, NERC certification Guidelines, On-the-Job qualification Guides, and Technical Qualification Training Checklists. The Technical Qualification Training Checklists contain competencies for the RC System Operator position and other operation positions. An analysis of each operator position was conducted by Subject Matter Experts (SME), Management, and training representatives to develop the checklists. These checklists provide a way to identify, track status, and document completion of required initial training for any new System Operator.

   MISO uses several means to provide initial and continuous training opportunities for System Operators. MISO Operations Technical Training provides the majority of the technical training. MISO Corporate Training provides much of the corporate and non-technical courses such as Standards of Conduct, Fitness for Duty, Ethics and Employee Conducts and Disciplinary Guidelines. Information Technology (IT) Education conducts training on computer-based applications such as Word, Excel, Access Database, etc. Continuing training is designed to keep all operating personnel knowledgeable of current policies, equipment and management expectations. Drills on emergency procedures and simulated exercises are included in the on-going training activities. Training records are maintained.

3. Standards of Conduct - MISO RC and MISO BA are independent of the merchant function. RC and BA Operators do not pass information or data to any wholesale merchant function or retail merchant function that is not made available as soon as practicable to all such wholesale merchant functions. MISO RC and MISO BA staff have completed training on MISO's Standards of Conduct. Refresher training on MISO's Standards of Conduct is conducted every year. Training records are maintained.

Appendix A

List of Transmission Owners within the MISO Reliability Coordination Area & the documents associated with each:

MISO Members	MISO Authority Documents				
	MISO TO Agreement	MISO Tariff	Coordination Agreement	RC Services Agreement	Appendix I
1803 Electric Cooperative	X	X			
AEP Indiana Michigan Transmission Company, Inc.	X	X			
AmerenCILCO	X	X			
AmerenIP	X	X			
AmerenUE and AmerenCIPS	X	X			
American Transmission Company, LLC	X	X			
Arkansas Electric Cooperative Corporation	X	X			
Big Rivers Electric Corporation	X	X			
Cedar Falls Utilities	X	X			
Central Minnesota Municipal Power Agency	X	X			
Citizen Electric Corporation	X	X			
City of Alexandria (LA)	X	X			
City of Ames	X	X			
City of Columbia, MO	X	X			
City of Marshall (MN)	X	X			
City Water and Light Plant of the City of Jonesboro	X	X			
City Water, Light & Power (Springfield, IL)	X	X			
CLECO	X	X			
Cooperative Energy	X	X			
Dairyland Power Cooperative	X	X			
Duke Energy Indiana, Inc.	X	X			
East Texas Electric Cooperative, Inc	X	X			
Entergy Arkansas, Inc.	X	X			
Entergy Gulf States Louisiana, L.L.C.	X	X			
Entergy Louisiana, LLC	X	X			
Entergy Mississippi Inc.	X	X			
Entergy New Orleans, Inc	X	X			
Entergy Texas, Inc.	X	X			
Great River Energy	X	X			
GridLiance Heartland LLC (3/1/2020)	X	X			
Henderson Municipal Power & Light	X	X			
Hoosier Energy Rural Electric Cooperative	X	X			
Indiana Municipal Power Agency	X	X			
Indianapolis Power and Light	X	X			
International Transmission Company					X
Lafayette Utility System	X	X			
Louisiana Energy and Power Authority	X	X			
Louisiana Generating	X	X			
Manitoba Hydro			X		
Michigan Electric Transmission Co, LLC	X	X			
Michigan Public Power Agency	X	X			
Michigan South Central Power Agency	X	X			
MidAmerican Energy Company	X	X			
Minnesota Municipal Power Agency	X	X			
Minnesota Power, Inc and subsidiary	X	X			

Missouri Joint Municipal Electric Utility Commission	X	X			
Missouri River Energy Services	X	X			
Montana-Dakota Utilities Co.	X	X			
Muscatine Power and Water	X	X			
Northern Indiana Public Service Company	X	X			
Northwestern Wisconsin Electric Company	X	X			
Otter Tail Power Company	X	X			
Pioneer Transmission	X	X			
Prairie Power	X	X			
Republic Transmission	X	X			
Rochester Public Utilities	X	X			
Southern Illinois Power Cooperative	X	X			
Southern Minnesota Municipal Power Agency	X	X			
Vectren for Southern Indiana Gas & Electric	X	X			
Wabash Valley Power Association, Inc.	X	X			
Wolverine Power Supply Cooperative, Inc.	X	X			
Xcel Energy, Inc.	X	X			
Non-MISO Members					
Consumers Energy				X	
Lansing Board of Water and Light				X	
Minnkota Power Cooperative				X	
Nexus Line, LLC				X	
NorthWestern Energy				X	
Sikeston Board of Municipal Utilities				X	

Appendix B

Balancing Areas within the MISO Reliability Coordination Area

	Balancing Area Name	Balancing Area	Local BA within MISO BA	Under MISO Tariff	Reliability Coordination Office		
					Carmel, IN	Eagan, MN	Little Rock, AR
0	Midcontinent ISO	MISO	-	Yes	X	X	X
1	Alliant Energy - CA - ALTE	ALTE	Yes	Yes	X		
2	Alliant Energy - CA - ALTW	ALTW	Yes	Yes		X	
3	Ameren Illinois	AMIL	Yes	Yes	X		
4	Ameren Missouri	AMMO	Yes	Yes	X		
5	Big Rivers Electric Corporation	BREC	Yes	Yes	X		
6	City Water Light & Power	CWLP	Yes	Yes	X		
7	CLECO	CLECO	Yes	Yes			X
8	Columbia Water & Light	CWLD	Yes	Yes	X		
9	Cooperative Energy	SME	Yes	Yes			X
10	Consumers Energy Company	CONS	Yes	Yes	X		
11	Dairyland Power Cooperative	DPC	Yes	Yes		X	
12	Detroit Edison Company	DECO	Yes	Yes	X		
13	Duke Energy	CIN	Yes	Yes	X		
14	Entergy Arkansas	EAI	Yes	Yes			X

15	Entergy Electric System	EES	Yes	Yes			X
16	Entergy Mississippi	EMBA	Yes	Yes			X
17	Great River Energy	GRE	Yes	Yes		X	
18	Henderson Municipal Power & Light	HMPL	Yes	Yes	X		
19	Hoosier Energy	HE	Yes	Yes	X		
20	Indianapolis Power & Light Company	IPL	Yes	Yes	X		
21	Lafayette Utility System	LAFA	Yes	Yes			X
22	Lone Star Transmission	GLH	Yes	Yes	X		
23	Louisiana Energy and Power Authority	LEPA	Yes	Yes			X
24	Louisiana Generating	LAGN	Yes	Yes			X
25	Louisiana Generation & Transmission	LAGT	Yes	Yes			X
26	Madison Gas and Electric Company	MGE	Yes	Yes	X		
27	MHEB, Transmission Services	MHEB	No	No		X	
28	Michigan Electric Coordinated System	MECS	Yes	Yes	X		
29	Michigan Upper Peninsula	MIUP	Yes	Yes	X		
30	MidAmerican Energy Company	MEC	Yes	Yes		X	
31	Minnesota Power, Inc.	MP	Yes	Yes		X	
32	Montana-Dakota Utilities Co.	MDU	Yes	Yes		X	
33	Muscatine Power and Water	MPW	Yes	Yes		X	
34	Northern Indiana Public Service Company	NIPS	Yes	Yes	X		
35	Northern States Power Company	NSP	Yes	Yes		X	
36	Otter Tail Power Company	OTP	Yes	Yes		X	
37	Southern Illinois Power Cooperative	SIPC	Yes	Yes	X		
38	Southern Indiana Gas & Electric Co.	SIGE	Yes	Yes	X		
39	Southern Minnesota Municipal Power Agency	SMP	Yes	Yes		X	
40	Upper Peninsula Power Co.	UPPC	Yes	Yes	X		
41	Wisconsin Energy Corporation	WEC	Yes	Yes	X		
42	Wisconsin Public Service Corporation	WPS	Yes	Yes	X		

Appendix C

Responsibilities and Authorities

The following lists the responsibilities/authorities of the MISO and the documents where those responsibilities/authorities are defined.

MISO Responsibilities / Authorities	
Document	**Responsibilities / Authorities**
MISO Transmission Owner Agreement	• **Security and Reliability of the Transmission System** • **Provide outage coordination** • **Take emergency action – including shedding load**
MISO Tariff	• **Curtailment of transmission service**
Coordination Agreement	• **Security and Reliability of the Transmission System** • **Provide outage coordination**
Interconnection Agreements	• **Agreement between Transmission Owners and Generation Owners**
Appendix "I"	• **Security and Reliability of the Transmission System** • **Outage coordination for independent transmission Companies (ITC, METC)**
RC Agreement	• **Provide Reliability Coordination Services**
Agreement Between Midcontinent ISO and Midcontinent ISO BAs to Implement TEMT	• **Agreement between Midcontinent ISO and BAs that are signatories to the agreement. The agreement does not apply to non-MISO members.** • **The agreement delineates the responsibilities between Midcontinent ISO and the BAs as is necessary to allow the TEMT, market tariff, to be implemented.**
MISO BA – Local BA Agreements	• **The agreement documents the coordination of the actions associated with the defined BA responsibilities**

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

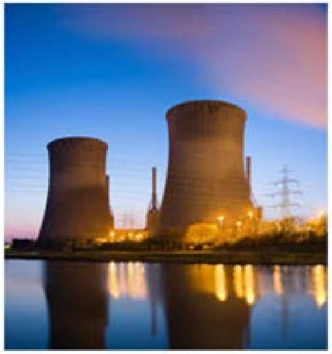
Reliability and Security Technical Committee Report

Stephen Crutchfield

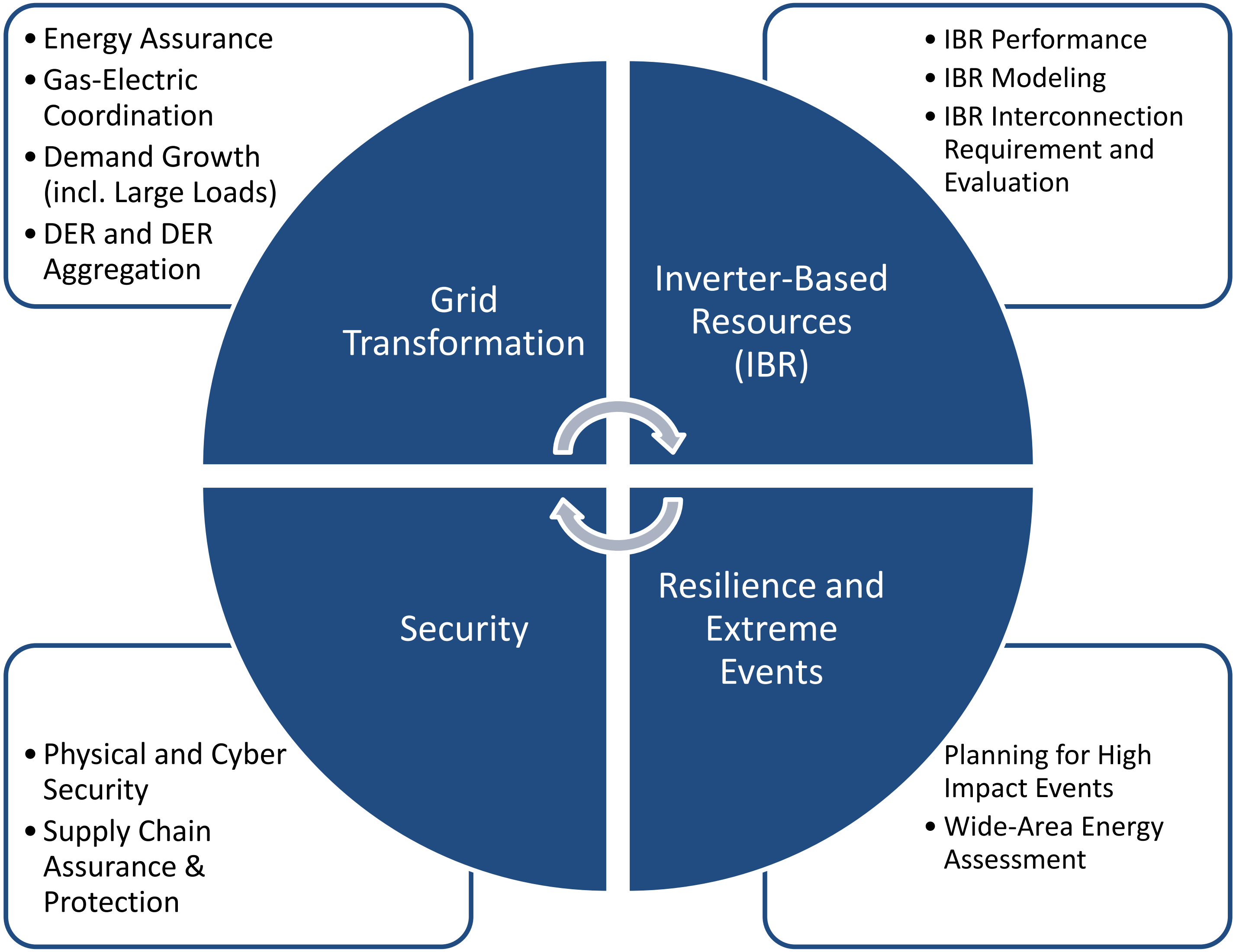
RTOS Meeting

February 4, 2025

RELIABILITY | RESILIENCE | SECURITY



2025 Strategic Plan Risk Priorities



RSTC Activities

- Annual Strategic Plan Update
  - On December 11 agenda for approval
- Sector Nominations / Elections (October/November)
  - Filled sector seats except sector 8
- At-large Nominations (December 2024) and slate selection (January 2025)
  - Will fill 5 at-large seats with a term expiring January 31, 2027
- Joint tiger team with Standards Committee to review SAR development process
  - Was put on hold pending Board request for further process reviews
  - Anticipate renewing this effort February/March 2025

2024 RSTC Annual Sunset Review

- Approved the RSTC Review Team recommendations to:
- Retire the 6GHz Task Force in March 2025.
- Combine the ERAWG and EGWG into a single working group.
- Promote the SCWG to a Subcommittee.
- Promote the EMTTF to a Working Group.
- Retain all other Working Groups and Task Forces that were reviewed in 2024 in their current form.

2025 RSTC Work Plan

- RSTC Work Plan Summit January 21-23, 2025
  - Reviewed all work plan items from each RSTC subgroup
- RSTC subteam members reviewing work plan items to identify high priority work plan items for 2025 to address Strategic Plan Risk Priorities
  - RSTC members are invited to provide feedback on priority of work plan items
- RSTC Executive Committee will review and approve/remand work plans for each group per the RSTC Work Plan Notional Process
- High Priority Work Plan Items will be reviewed at the March 2025 RSTC meeting

Future Meetings

- March 12-13, 2025 (In-person, Clearwater, FL)
- June 11-12, 2025 (Hybrid, Folsom; CAISO, Joint SC meeting)
- September 10-11 (Hybrid, Austin; TexasRE)
- December 10-11, 2025 (Virtual)

Questions and Answers