SPP RELIABILITY PLAN

0820PCS00108

Business Owner: CJ Brown
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Approved By:	
SME Signature (Bryan Wood)	Date

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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	1/11/2021	4/1/2021	Added GRID to "BAs and TOPs in SPP RC Areas" section in the Appendix effective 4/1/2021.

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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. 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.

NOTE: All steps/procedures related to the Western Interconnection will be effective beginning December 3, 2019. Unless explicitly defined, any reference to “RC” will be 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-Areas 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 does and will act 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, except in cases involving endangerment to the safety of employees or the public. 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 is tasked with maintaining 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.

C. Common Tasks for Next Day Operations

1. SPP coordinates operations and ensures reliable operation of the BES by utilizing System Operating Limits (SOLs), 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 secured FTP site.

2. SPP is responsible for determination of IROLs within the SPP RC Areas. SPP has documented methodologies for determination of IROLs in the SPP RC Areas. 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 is 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 analysis 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. SPP also performs a next-hour assessment of capacity and adequacy on an hourly basis. These analysis 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 analysis are performed daily with the exception of the weekend and holiday analysis 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 analysis are conducted daily which include Remedial Action Schemes (RAS). In these contingency analysis, 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 As required by the RC-RC Agreements it has with its neighboring RCs, 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 BAs 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.

3.6. 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.

3.6.1. 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.

3.7. 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.

3.8. SPP monitors current external impacts on its system from external network load, Market flows in the Eastern Interconnection, external native network load (NNL) and transactions.

3.9. SPP receives and reviews resource plans and generation schedules from its Reliability customers.

3.10. 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 the SPP West RC 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 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 tag and 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 In accordance with NERC EOP-010, 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.

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.

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 Market Flows need to be curtailed 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 curtailment. SPP updates its Market Flow information in the IDC every 5 minutes and will monitor this information to verify that SPP implemented the appropriate Market Flow curtailment instructions from the IDC.

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 delineates 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. Coordination Agreements and Data Sharing

1. SPP has executed coordination agreements or plans with its neighboring RCs to augment and further support the reliability of their respective RC Areas.

2. SPP and other RCs share data (via ISN and RCIS) as requested to support reliability coordination. SPP's RC Members and Reliability Customers are required to submit data necessary to support SPP's RC function pursuant to applicable SPP RDS.

I. 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 its two 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.

J. 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 PER-005 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 in the Learning Management System for recordkeeping and reporting purposes. The SPP Learning Center (LMS) contains all information required by the NERC Continuing Education program 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 (EDE)		X	X	
Farmington Electric Utility System (FEUS)		X		X
Grand River Dam Authority (GRDA)		X	X	
New Harquahala Generating Company (HGBA)	X			X
Griffith Energy (GRIF)	X			X
City of Independence Power & Light Department, Missouri (INDP)		X	X	
Gridforce Energy Management (GRID)	X			X
Intermountain Rural Electric Association (IREA)		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	

Entity	BA	TOP	East	West
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 and Western Interconnections.*

Appendix B – SPP RC Procedures

Procedures applicable to the SPP Reliability Coordination Areas:

Document ID	Document Title
0800PCS00115	Communications
0820PCD00105	Congestion Management *
0800PCD00036	Contingency Reserves
0870PCD00110	Daily Reliability Assessment
0803PCS00009	Desk Qualifications Program Overview
0820PCD00039	EEA
0800PCD00107	Effective Limits
0800PCD00102	Emergency Evacuation
0820PCD00011	Geomagnetic Disturbances (GMD)
0820PCD00028	High Low Voltage Support
0800PCD00134	Islanding and Restoration
0800PCD00047	Loss of Necessary Applications
0820PCD00106	M2M Flowgate Coordination *
0800PCD00106	Manual Commitments
0800PCD00038	Minimum Generation Situations
0820PCD00084	NERC Reliability Coordinator Hotline Call Procedures
0800PCD00044	Out of Merit Energy (OOME)
0870PCD00046	Outage Coordination Study
8300PCD00001	Path and Congestion Management **
0820PCD00100	Perform System Study
0860PCD00102	Permanent Flowgates
0820PCS00101	RC Operations
0801PCD00001	Reporting Requirements
0800PCD00051	Reserve Zone Shortages
0820PCD00062	Safe Operating Mode (SOM) *
0820PCD00112	Special Protection Systems/Remedial Action Scheme Updates (SPS/RAS)
0820PCD00107	SPP RC Area Restoration Plan *
8300PCD00002	SPP RC Area Restoration Plan for the Western Interconnection **
0860PCD00101	Temporary Flowgates *

Document ID	Document Title
0800PCD00040	Time Error Corrections
0870PCS00061	Transmission Maintenance Review
0800PCD00069	Weather Analysis and Conservative Operations

** Eastern Interconnection only.*
*** Western Interconnection only.*