Southwest Power Pool

TRANSMISSION WORKING GROUP MEETING

June 13, 2018

SPP Corporate Campus – Little Rock, AR

• Summary of Action Items •

1. Approved the meeting agenda

Southwest Power Pool

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• M I N U T E S •

Agenda Item 1 – Administrative Items

Call to Order

TWG Chair Travis Hyde called the meeting to order at 9:01 am. The following members were in attendance (Attachment 1a):

Travis Hyde (Chair), Oklahoma Gas & Electric
Scott Benson, Lincoln Electric System
John Boshears, City Utilities of Springfield
Derek Brown, Westar and KCP&L, Evergy Companies
Joe Fultz, Grand River Dam Authority
James Ging, Kansas Power Pool
Kalen Kelley, Western Farmers Electric Cooperative
Jim McAvoy, Oklahoma Municipal Power Authority
Matt McGee, American Electric Power
Michael Mueller, Arkansas Electric Cooperative Corporation
Alan Myers, ITC Great Plains
Gayle Nansel, Western Area
John Payne, Kansas Electric Power Cooperative
Chris Pink, Tri-State G&T
Jason Shook, GDS Associates, Inc.
Matthew Stoltz, Basin Electric Power Cooperative

Proxies

The following proxies were provided for the meeting (Attachment 1b – Proxies):

- Jence Mandizha (Midwest Energy) proxy for Nathan McNeil (Midwest Energy)
- Dustin Betz (NPPD) proxy for Randy Lindstrom (NPPD)
- Josh Verzal (OPPD) proxy for Dan Lenihan (OPPD)
- Rachel Hulett (SC MCN) proxy for Noman Williams (SC MCN)
- Michael Wegner (ITC Great Plains) partial proxy for Alan Myers (ITC Great Plains)

Kirk Hall, TWG staff secretary informed the group there was a quorum.

Travis requested approval of the meeting agenda with a modification to discuss the Lawrence Hill transformer under the 2018 ITPNT agenda item.

Motion: Chris Pink made a motion to approve the modified agenda. Joe Fultz seconded the motion, which passed with no opposition.

Agenda Item 2 – 2018 ITPNT Update

Lawrence Hill 230/115 kV Transformer

Kirk opened the discussion by highlighting the context around the use of transmission operating guide (Attachment 2a – Transmission Operating Guide Usage) in SPP processes, specifically the ITP process. After a quick discussion, Kirk moved on to the Lawrence Hill 230/115 kV transformer and informed the TWG that it was inadvertently excludes from previous discussions regarding the use of transmission operating guides. Because of this omission, staff was requesting the TWG approve the use of an op guide or transmission solution to solve the need observed in the 2018 ITPNT. Derek Brown (Westar Energy) discussed Westar's position on the issue suggesting a transmission solution was necessary for due to: the operating guide not including a short-term emergency rating and the issue is being driven by load in the Lawrence, KS area. The group discussed the merits of using the generation in the area (as described in the op guide) to address the issue, including the age of the Lawrence Energy Center units and the Lawrence Hill transformer, versus a transmission solution.

> **Motion: Derek Brown made a motion directing staff to seek a transmission solution to address the Lawrence Hill 230/115 kV transformer in the 2018 ITPNT. Matthew Stoltz seconded the motion. The motion passed with 8 'Yes' votes, 6 'No' votes, and 5 abstentions. Four members were absent from the vote. Those voting against the motion included: Travis Hyde (OKG&E), Scott Benson (LES), John Boshears (CUS), Kalun Kelley (WFEC), Jim McAvoy (OMPA), and Jason Shook (GDS representing ETEC). Those abstaining from the vote included: Jence Mandizha (MIDW), James Ging (KPP), Josh Verzal (NPPD), and Chris Pink (Tri-State G&T)**

After the meeting, the individuals voting against the motion provided the following reasons for their vote.

Travis Hyde (OKG&E)

> *OG&E would like to see a more detailed process developed (tariff/criteria) that explains the process of evaluation of when a permanent Transmission Operating Guide (TOG) is no longer desired or valid. What level of studies would be required to determine if the TOG is no longer valid? Since many of the OP Guides mitigate more stringent NERC violations beyond the standard (N-1) contingency evaluation, who should be paying for infrastructure than needs to be built to mitigate the problem if an Op Guide is removed? Especially if a TOG has been valid for the last 15-20 years. OG&E feels that further discussion is warranted around the topic of TOG's before projects get identified and issued NTC's*.

Jim McAvoy (OMPA)

> *As others have stated, many companies have used TOG's for many years to mitigate thermal or voltage issues. Questions about the ongoing effectiveness of TOG's, who should pay if a transmission project replaces a TOG, and when is a TOG no longer valid need solid answers. For these reasons, OMPA voted NO on the motion.*

Scott Benson (LES)

> *Although LES appreciates the particular needs in this area of the system, we voted against the motion because we'd like to revisit the general process for retiring TOGs before acting on this one specific issue. This is something that would be applicable to many more areas across the footprint, so we feel a more holistic determination would be best before we begin making one-off decisions.*

Kalun Kelley (WFEC)

> *I voted no because the reasons I stated in my prior abstention have not been addressed. Essentially, the construction of network upgrades to alleviate the use of these TOGs is not addressed in our current processes. TWG should not be approving projects that are not*

supported by a scope that provides a consistent process for analysis and justification parameters. I support the development of these processes and parameters so that the TWG will be able to consistently analyze concerns like this in the future.

After the meeting, the individuals abstaining from the vote provided the following reasons for their abstention.

Dustin Betz (NPPD)

NPPD abstained due to initial uncertainty surrounding the Lawrence Hill generation units and future retirement plans. NPPD supports the notion of addressing N-1 issues with transmission solutions, but the information presented during the discussion phase of the motion approval created some confusion in our mind about the need. Clarification was made after the vote from SPP and Westar about Lawrence Hill generation and the N-1 need remains intact. GRDA actually changed its vote from NO to YES due to this clarification so the motion passed. NPPD did not want to oppose the motion moving forward so we left our abstention vote stand as it wouldn't affect the outcome of the vote.

James Ging (KPP)

KPP abstained because it was not clear if the TOG has become ineffective or if replacing the transformer was just a nice project to have. It was clear to me that the Op guide has worked for many years, but not convinced it has become uneconomical. The replacement of the transformer was due to the generation. If the generation was to go away the need for the transformer replacement would go away. So given the unclarity of the future of the units the OP guide seemed to be the best option. I agree with Travis that we as a group need to work much harder on the policy surrounding TOG guides and how cost are allocated. I did not oppose the project because Westar has done a great job of doing project to relieve import limits around its system. This very well could be a solid project and was needing more information around the economic impacts if the TOG stays or is removed.

Chris Pink (Tri-State G&T)

I abstained because the issues and their history weren't entirely clear to me. Also, the future status of the primary project driver (generation) was questioned. Nevertheless, I would have been fine with approval if that was the will of the rest of the working group. I agree that OP guides are not long term solutions.

Josh Verzal (OPPD)

OPPD abstained due to unclear guidance on the application and effectiveness of standing TOGs to alleviate needs in the ITP study process. From OPPD's perspective, our standing TOGs are legacy TOGs that were originally set up as supplemental Operating aids for our transmission flowgates and were implemented as a last resort tool for the Transmission Operators to use in the event of real-time operational issues on the transmission system. With the advent of the Integrated Market most, if not all, of these are now addressed by the Market dispatch and the TOGs are not the primary means of mitigation. For all other reliability needs that are identified out of the ITP process that do not have an existing TOG, generation redispatch is not tested as a fix to mitigate the needs. If this principle of utilizing generation redispatch as the first option to fix needs was applied to all reliability needs in the portfolio, there would potentially be fewer projects being issued out of the ITP process. OPPD is not necessarily saying that is the way the needs should be evaluated, but this shows the need for additional policy or guidance regarding generation redispatch and TOGs.

Jence Mandizha (MIDW)

The fact that SPP dispatches Westar's generating units #4 and #5 at Lawrence Hill in a way that overloads the Lawrence Hill 230/115 kV transformer works in favor of the transformer upgrade. The age of the transformer and generating units (30 ~ 50 years) and the unclarity of the future of generation at Lawrence Hill favors further use of the OP guide. More importantly MIDW abstained because it was not clear whether the OP guide that had been used for many years in this case had become ineffective.

Operating Guide Usage and Consideration of Additional Needs

Kirk moved on to discuss the additional analysis staff had completed around the Wolf Creek area based on the discussion and approved TWG motion from the May 31 TWG Net Conference. During that meeting, the TWG recommended transmission solutions be sought out to solve the Navy – Grand Avenue – Northeast 161 kV line and Wolf Creek 345/69 kV transformer, while considering other needs in the local area. Discussion during that meeting focused on the angular stability issues observed in various SPP studies near Wolf Creek. After the prior TWG meeting, staff performed some additional analysis to allow the TWG to make an informed decision, including steady state, economic, and transient stability analysis. Additionally, the Kirk covered options for the TWG to consider on how to continue evaluating the issues around Wolf Creek. The TWG discussed the options presented and the historical usage of the op guide in other SPP processes.

Motion: Jason Shook made a motion to use the Wolf Creek Op Guide for the 2018 ITPNT and continue discussing how to move forward evaluating the issues around Wolf Creek. The motion was seconded by Jim McAvoy. Prior to the vote, Derek Brown commented to the TWG that the motion being considered was not consistent with the motion made during the prior TWG net conference, when the TWG previously discussed the issues around Wolf Creek. The motion passed with 10 votes in favor, 9 votes against, and 1 abstention. Three members were absent from the vote. The votes against the motion were made by Derek Brown (WERE), Joe Fultz (GRDA), Dustin Betz (NPPD), Matt McGee (AEPW), Gayle Nansel (WAPA), John Payne (KEPCo), Chris Pink (TSG&T), Matthew Stoltz (BEPC), Rachel Hulett (SC MCN). The abstention was provided by Alan Myers (ITC GP).

After the meeting, the individuals voting against the motion provided the following reasons for their vote.

Derek Brown (KCP&L and Westar, Evergy Companies)

KCPL and Westar, Evergy companies, voted NO because the motion was inconsistent with the requirements for an effective TOG as detailed in Appendix B of the ITP Manual and because there was no clear action taken to address the issues around Wolf Creek. The TWG should have been more consistent in its treatment of all TOG impacted facilities in the 2018 ITPNT Study. Regarding the Wolf Creek stability issues, the motion did not address the thermal issue for the Wolf Creek transformer or set a clear direction going forward. The motion simply stated that TWG will be "continuing discussion how to move forward evaluating issues around Wolf Creek." Evergy agrees that more discussion is needed regarding the use of TOGs in future ITP studies. However, there has been sufficient information provided to the TWG showing that stability margins have degraded at Wolf Creek, there is a thermal issue with the transformer that needs addressed, and SPP staff has shared that a potential 345 kV line solution provides some economic benefit. TWG should recommend a study be performed to identify the best solution to the thermal and stability issues as soon as possible.

Rachel Hulett (SCMCN)

I voted no as I thought TWG could provide better guidance for future study plans of the transient stability issues. I thought the motion was too generic in that regard.

Chris Pink (Tri-State G&T)

I voted no because I thought the proper direction would have been to recommend a fix (replacement) to the transformer overload problem.

Matthew Stoltz (BEPC)

I voted no as I thought TWG could have provided better guidance regarding the plan to consider the transient stability issues. I thought the motion was too generic in that regard. I'm concerned that the local TO/TOP is uncomfortable with the effectiveness of their operating guide and therefore TWG should of provided a clearer path to address their concerns. I would have voted yes on the steady state fix.

Matt McGee (AEP)

AEP voted against the motion because we do not believe it is proper for SPP to continue to rely upon a TOG for an N-1 thermal overload of the Wolf Creek transformer. The owner of the facilities says the TOG is not effective and does not support using it for planning purposes, and there is no short-term rating needed for implementation of the TOG. We believe a transmission solution is needed for the 2018 ITPNT N-1 issue at Wolf Creek and that replacing the transformer is a reasonable solution.

Gayle Nansel (WAPA)

I voted NO as I felt we had adequate information to provide direction and a recommendation. I felt a transmission solution for Wolf Creek 345/69 KV transformer could have been recommended by TWG to address the thermal issue identified in the 2018 ITPNT study by replacing the transformer which I believe is nearing the end of its expect service life (35+ years old). The stability issue surrounding Wolf Creek still needs to be considered for future discussion, study and vetting through future SPP studies.

Joe Fultz (GRDA)

GRDA voted no because of the inconsistencies in the ITP Manual referring to the use of STER's to implement the TOG. There are no applicable STERs' assigned to these facilities. GRDA believes the TWG should discuss the topic of system stability issues (N-1-1) that continue to worsen as more resources continue to be added to the grid. GRDA would've voted yes to upgrade the Wolf Creek transformer to mitigate the thermal overload.

Dustin Betz (NPPD)

NPPD voted NO due to inconsistency with the approach of addressing N-1 issues with transmission solutions. NPPD would have liked to have seen a transmission solution for Wolf Creek 345/69 KV transformer be recommended by TWG to be consistent in the treatment of these issues. NPPD was in favor of the Wolf Creek 345/69 kV transformer replacement project to address the thermal issue identified in the 2018 ITPNT study. The N-1-1 stability issues surrounding Wolf Creek should still be considered for future discussion and study by SPP. The Wolf Creek stability issues should continue to be vetted through consultation with the TWG in future studies.

Final Project List

Kirk, then moved on to discuss the final project list (Attachment 2b – 2018 ITPNT Final Project List), including the changes approved during the meeting for the Lawrence Hill 230/115 kV transformer and the use of the Wolf Creek op guide. Western Farmers' Electric Cooperative also requested the removal of the Lebanon cap bank project due to concern around the duplicative modeling of a capacitor bank in the area as well as power factor modeling concerns.

> **Motion: Based upon SPP staff recommendations and specific TWG direction John Boshears made a motion to approve the 2018 ITPNT Final Project List. Rachel Hulett seconded the motion, which passed unanimously.**

Agenda Item 3 – RR 309: Separation of RC Area SOL Methodology from Planning Criteria

Neil Robertson, SPP staff, presented RR 309 (Attachment 3 – RR 309: Separation of RC Area SOL Methodology from Planning Criteria) to the TWG for their approval. The TWG discussed the RR and coordination with other current or future NERC standard revisions and made some revisions to the document prior to approval.

> **Motion: Gayle Nansel made a motion to approve RR 309 as modified during the meeting. Joe Fultz seconded the motion. The motion to approve the RR was approved unanimously.**

Agenda Item 4 – Updated Map Request Process

This item was not discussed due to time restrictions.

Agenda Item 5 – 2018 Annual Flowgate Assessment Report

Melanie Hill, SPP staff, reviewed the 2018 Annual Flowgate Assessment Report (Attachment 4 – 2018 Annual Flowgate Assessment Report) with the TWG and asked for their approval.

> **Motion: Joe Fultz motioned to approve the 2018 Annual Flowgate Assessment Report, seconded by Dustin Betz. The motion passed unanimously.**

Respectfully Submitted,

Kirk Hall
Secretary

All sessions in Central Daylight Time (Chicago, GMT-05:00)
Session detail for 'TWG Net Conference':

Participant	Name	Email
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71	Ben Bright	bbright@spp.org
72	Dustin Betz (NPPD)	ddbetz@nppd.com
73	Tim Hall	timhall@southernco.com

Kirk,

I will be traveling tomorrow June 13th during the TWG conference call and will provide my proxy to Rachel Hulett.

Thanks

Noman Williams
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Kirk,

Josh Verzal will be my proxy for the TWG call tomorrow.

Thanks,

Dan Lenihan, P.E.
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From: bounce-63155-118681@spplist.spp.org <bounce-63155-118681@spplist.spp.org> **On Behalf Of** Kirk Hall
Sent: Tuesday, June 12, 2018 2:48 PM
To: Transmission Working Group <twg@spplist.spp.org>
Subject: **External Email** Background Material Update: TWG 6/13/18 Agenda & Background Materials posted
Importance: High

Kirk and Travis,

I will not be able to attend the 6/13 TWG call and would like to give my proxy to Jence Mandizha who is our transmission planning engineer.

Thanks,
Nathan

Nathan McNeil, PE
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Kirk & Travis – I have a conflict with the 6/13/18 TWG Meeting, so I am giving my TWG voting proxy to Dustin Betz.

Thanks

Randy R. Lindstrom
Transmission Planning Supervisor
System Planning & Transmission Business
Nebraska Public Power District Operations
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From: Audrey White [mailto:awhite@spp.org]
Sent: Wednesday, June 06, 2018 4:58 PM
To: SPP TWG (EXPLODER); SPP TWG (Members Only)
Subject: TWG 6/13/18 Agenda & Background Materials posted

TWG 6/13/18 Agenda & Background Materials have been posted to the SPP website for your review at the link shown below:

TWG Meeting Materials

TWG 6/13/18 Online Registration

Audrey White | Administrative Assistant | awhite@spp.org |501-688-2531 (O)|501-350-1158 (C)
201 Worthen Drive | Little Rock, AR 72223-4936
Southwest Power Pool | SPP.org | twitter.com/SPPorg | facebook.com/SouthwestPowerPool
Helping our members work together to keep the lights on…today and in the future

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Kirk,

I'm going to have to jump off the TWG call in roughly 10-15 minutes. At that point Michael Wegner will have my proxy.

Thanks,
Alan K. Myers, P.E.
Director, Regional Planning
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TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.

2018 ITPNT Transmission Operating Guide Usage

TWG

June 13, 2018

Overview

- Background
  - SPP staff and/or stakeholders identified a number of transmission operating guides currently on file with SPP operations
- Objective
  - Discuss Lawrence Hill 230/115 kV transformer violation and get TWG recommendation on Op Guide usage
  - TWG confirmation of specific justification stating why the Op Guides in question are unable to be used to mitigate the needs
    - Navy – Grand Avenue – Northeast 161 kV line
    - Wolfcreek 345/69 kV transformer
  - Discuss options for consideration of additional issues observed in the local area around the needs

Requirement to assess alternative proposals

- Attachment O Section III.7.c
  - *"The Transmission Provider will consider, on a comparable basis, any alternative proposals which could include, but would not be limited to, generation options, demand response programs, "smart grid" technologies, and energy efficiency programs. Solutions will be evaluated against each other based on a comparison of their relative effectiveness of performance and economics."*

SPP Transmission Operating Guide (TOG) Review Procedure (2016 ITP Manual Appendix B)

- In most cases, TOGs are not intended to indefinitely defer needed Transmission System upgrades
- Effective TOGs shall be utilized in all transmission tariff service functions and OATT planning processes
  - An effective TOG shall continue to be used in evaluation of the ITP and ATSS unless the facility-owning Transmission Owner or transmission operator withdraws the TOG
  - In cases where the TOG is withdrawn before the TOG becomes ineffective, any Transmission System Upgrades lie with the Transmission Owner
- A TOG is considered an effective solution for facilities that are not listed in the TOG if, in the act of implementing the TOG for the elements listed, other overloads or voltage violations are corrected.

SPP Transmission Operating Guide (TOG) Review Procedure (2016 ITP Manual Appendix B)

Effective TOGs

1. A TOG addressing Transmission System loading must include a short-term emergency rating which allows sufficient time to implement the TOG.

2. A TOG requiring generation redispatch must indicate if generator location is critical and, if so, must state in detail which units or plants will be re-dispatched. Absence of such specificity means location is not critical and generators may be selected from the fleet the entity has authority to run. The ramp rate of the generation must be capable of relieving the overload or voltage issue within the time allowed as specified in the TOG.

3. A TOG must not cause a violation elsewhere on the Transmission System.

4. A TOG addressing a voltage violation must provide for restoring minimum acceptable voltage conditions within a time frame so as not to cause permanent equipment damage.

Current SPP Strategic Plan

- Maintain an Economical, Optimized Transmission System
  - *While SPP facilitates the future development of a robust electric transmission infrastructure that will enable the maximum use of capital-intensive generating resources for the benefit of all end-use customers in the SPP footprint, it should continue to develop and enhance policies, tools, and practices to optimize the use of the existing transmission system.*

Notes from 5/31 TWG Call

- TWG approved a motion for staff to pursue transmission solutions for 2 issues in the 2018 ITPNT instead of using existing Op Guides
  - Navy – Grand Avenue – Northeast 161 kV Line
  - Wolf Creek 345/69 kV Transformer
  - 13 in favor, 5 against, 3 abstentions, 3 absent
- Angular stability issue around Wolf Creek area has degraded over time due to an increase in west to east transfers across the SPP system
  - Newer dynamics models more accurately represent how the system reacts

Notes from 5/31 TWG Call

- Reasons for Op Guide ineffectiveness
  - Op Guides not sufficient for long term planning
  - No defined short-term emergency rating in the Op Guides
  - For Wolf Creek, Op Guide written for N-1-1 angular stability purposes therefore not useful for planning purposes
- TWG members somewhat split on whether the issues should be addressed in the NT
  - Potential 2018 ITPNT Scope change
  - Op Guide has been used for years
  - Issue should have been resolved in the GI stability process

Lawrence Hill 230/115 kV Transformer

- Originally posted as Summer S5 only issue in 2019 and 2022
  - Updated needs assessment posted Jan 12, 2018 included new criteria violations from Pass 7 BR model
  - Lawrence Hill included for 2019 and 2022 Summer
- During solution development, Year 5 BR need inadvertently invalidated
- Once S5 Summer models removed from study, only remaining 'valid' violation in Year 2 BR
- Based upon dismissal of Year 2 violations, use of op guide for Lawrence Hill transformer not formally discussed

Motion Request

- TWG motion needed to direct staff on the use of the op guide or a transmission solution to address the Lawrence Hill 230/115 kV transformer violation in the 2018 ITPNT
- Motion to use the Op Guide for the 2018 ITPNT and to

Quantitative and Qualitative Assessments near Wolf Creek

- Various studies have observed thermal and angular stability issues in the Wolf Creek area
  - Transformer replacement addresses thermal issues only
  - Fourth 345 kV circuit from Wolf Creek may address the observed thermal and stability issues
- Additional analysis completed by staff
  - Angular stability evaluation new 345 kV in current TPL models and IBIS models
  - Determination of steady state issues that may be caused by new 345kV line out of Wolf Creek in 2018 ITPNT models
  - Reconsideration of economic analysis

Analysis Wolf Creek – Emporia 345 kV line

- No angular instability observed with line in service under N-2 contingency when unit derated
  - Currently determining if a limit remains
- Steady state analysis with new line causes increased loading on the Lawrence Hill 230/115 kV transformer
  - New violation observed in Scenario 0 cases
  - Addressed by use of Op Guide or new transformer

Analysis Wolf Creek – Emporia 345 kV line

- Economic analysis reconsidered
  - Wolf Creek op guide implemented incorrectly in upgrade case(2017 ITP10 F3)
  - Op guide usage increased, to simulate decreased stability margins
  - With op guide removed, indicative project B/C ratio increases to ~.5 BC
  - Previously determined to be negative in Y10
  - Additional economic benefit due to increased availability of low cost energy with little to no affect on congestion

Options

- Option 1: Op Guide
- Option 2: Replace Wolf Creek 345/69 kV Transformer
- Option 3: New 345 kV line out of Wolf Creek
- Option 4: Comprehensive evaluation
  - 4a: 2019 ITP (Scope modification)
  - 4b: High Priority Study
  - 4c: Extend 2018 ITPNT

Considerations for Options

- Option 1: Use Op Guide
  - Solves the issues in the ITPNT and addresses angular stability issue
  - Used as mitigation in 2017 ITPNT
  - Allows for continued evaluation
- Option 2: Wolf Creek 345/69 kV transformer
  - Addresses thermal need in 2018 ITPNT
  - N-1-1 angular stability issue remains

Considerations for Options

- Option 3: New 345 kV line out of Wolf Creek
  - Higher project cost
  - Solves thermal and angular stability issues
- Option 4: Comprehensive Evaluation
  - Incur additional costs for study work
  - Recommendation for a solution considering reliability and economics

Motion Request

- TWG motion needed to determine the proper approach to address the issues observed in the 2018 ITPNT around Wolf Creek
- Motion to use the Op Guide for the 2018 ITPNT and continue discussion how to move forward evaluating the issues around Wolf Creek

SEE BELOW FOR LEGEND

	Project Description/Comments	Upgrade Description	State	Study Cost Estimate*	Idev Name	Needs Addressed
Project #1	New 50 MVAR reactor at Brookline 345kV.	New 50 MVAR reactor at Brookline 345kV.	MO	$ 4,175,203	Brookline_Substation_Expansion_and_Reactor.idv	2018ITPNT-RVN2440976; 2018ITPNT-RVN2440977
Project #5	Upgrade the existing 230/115 kV transformer at Sundown	Upgrade the existing 230/115 kV transformer at Sundown and replace any terminal equipment required to meet the full rating of the new transformer.	TX	$ 3,434,979	Sundown_Transformer_Upgrade.idv	2018ITPNT-RON2389429; 2018ITPNT-RON2429629; 2018ITPNT-RON2401542; 2018ITPNT-RON2401508; 2018ITPNT-RON2403356; 2018ITPNT-RON2403363; 2018ITPNT-RON2403420; 2018ITPNT-RON2388279; 2018ITPNT-RON2387998; 2018ITPNT-RON2387983; 2018ITPNT-RON2387857; 2018ITPNT-RON2404942; 2018ITPNT-RON2404978
Project #6	Replace terminal equipment on the Clauene to Terry County 115 kV line	Replace terminal equipment on the Clauene to Terry County 115 kV line and address any line clearance concerns to meet or exceed the line's conductor rating.	TX	$ 520,574	Clauene-Terry_County_Terminal_Equipment.idv	2018ITPNT-RON2398899; 2018ITPNT-RON2398895; 2018ITPNT-RON2398902
Project #10	New terminal equipment on the 161 kV branch from Brookridge to Overland Park.	New terminal equipment on the 161 kV branch from Brookridge to Overland Park.	KS	$ 538,000	Brookridge-Overland_Park_Terminal_Equipment.idv	2018ITPNT-RON2429428; 2018ITPNT-RON2388014; 2018ITPNT-RON2389343; 2018ITPNT-RON2401722; 2018ITPNT-RON2382631; 2018ITPNT-RON2403601; 2018ITPNT-RON2405169; 2018ITPNT-RON2432492
Project #13	New terminal equipment on the 161 kV branch from Olathe to Switzer.	New terminal equipment on the 161 kV branch from Olathe to Switzer.	KS	$ 1,088,000	Olathe-Switzer_Terminal_Equipment.idv	2018ITPNT-RON2432729; 2018ITPNT-RON2389551; 2018ITPNT-RON2401980; 2018ITPNT-RON2405219; 2018ITPNT-RON2387965; 2018ITPNT-RON2429599; 2018ITPNT-RON2382774; 2018ITPNT-RON2403603
Project #28	Rebuild 4.2 miles of 69 kV line from VBI North to Figure Five.	Rebuild 4.2 miles of 69 kV line from VBI North to Figure Five.	AR	$ 3,409,700	VBI_North-Figure_Five_Rebuild.idv	2018ITPNT-RON2429677; 2018ITPNT-RON2432698
Project #29	Reconductor 3.0 miles of 115 kV line from Lewis to Richland with 477 ACSR. Adjust CT taps to 1200/5 and replace structures as needed.	Reconductor 3.0 miles of 115 kV line from Lewis to Richland with 477 ACSR. Adjust CT taps to 1200/5 and replace structures as needed.	MT	$ 105,000	Richland-Lewis_Rebuild.idv	2018ITPNT-RON2391998; 2018ITPNT-RON2407583; 2018ITPNT-RON2407583; 2018ITPNT-RON2391998
Project #32	Replace terminal equipment on the Carlisle to Murphy 115 kV line	Replace terminal equipment on the Carlisle to Murphy 115 kV line and address any line clearance concerns to meet or exceed the line's conductor rating.	TX	$ 319,760	Carlisle-Murphy_Terminal_Equipment.idv	2018ITPNT-RON2432317; 2018ITPNT-RON2404965; 2018ITPNT-RON2401466; 2018ITPNT-RON2403304
~~Project #43**~~	~~Replace 345/69 kV transformer at Wolf Creek.~~	~~Replace 345/69 kV transformer at Wolf Creek.~~	~~KS~~	~~$ 10,945,773~~	~~Wolf_Creek_Transformer_Upgrade.idv~~	~~2018ITPNT-RVN2403808; 2018ITPNT-RON2391797; 2018ITPNT-RON2407478; 2018ITPNT-RON2387919; 2018ITPNT-RON2387917; 2018ITPNT-RON2388018; 2018ITPNT-RON2387972~~
Project #54	New 5.64 mile 161 kV line from Blue Valley to Crosstown.	Install any necessary terminal upgrades at Crosstown to accommodate new 161 kV line from Blue Valley. Install any necessary terminal upgrades at Blue Valley to accommodate new 161 kV line from Crosstown. New 5.64 mile 161 kV line from Blue Valley to Crosstown.	MO MO MO	$ 8,951,824	Blue-Valley-Crosstown_New_Line.idv	2018ITPNT-RVN2431786; 2018ITPNT-RON2401528; 2018ITPNT-RON2401863; 2018ITPNT-RON2401665; 2018ITPNT-RON2401782; 2018ITPNT-RON2401711; 2018ITPNT-RON2401685; 2018ITPNT-RON2401844; 2018ITPNT-RON2402059; 2018ITPNT-RON2432316; 2018ITPNT-RON2432735; 2018ITPNT-RON2432511; 2018ITPNT-RON2432446; 2018ITPNT-RON2432488; 2018ITPNT-RON2432646; 2018ITPNT-RVN2389807
~~Project #60~~	~~New 24 MVAR (12x2) capacitor bank at Lebanon 138kV.~~	~~New 24 MVAR (12x2) capacitor bank at Lebanon 138kV.~~	~~OK~~	~~$ 1,000,000~~	~~Lebanon_Cap_Bank.idv~~	~~2018ITPNT-RVN2402390; 2018ITPNT-RVN2402480; 2018ITPNT-RVN2402675; 2018ITPNT-RVN2402417; 2018ITPNT-RVN2402082; 2018ITPNT-RVN2402889; 2018ITPNT-RVN2402577; 2018ITPNT-RVN2402501; 2018ITPNT-RVN2402580; 2018ITPNT-RVN2402185; 2018ITPNT-RVN2432978; 2018ITPNT-RVN2433578; 2018ITPNT-RVN2433245; 2018ITPNT-RVN2433302; 2018ITPNT-RVN2432980; 2018ITPNT-RVN2433252; 2018ITPNT-RVN2433353; 2018ITPNT-RVN2388419; 2018ITPNT-RVN2388636; 2018ITPNT-RVN2388967; 2018ITPNT-RVN2404644; 2018ITPNT-RVN2404142; 2018ITPNT-RVN2404366; 2018ITPNT-RVN2428932; 2018ITPNT-RVN2428924; 2018ITPNT-RVN2429186; 2018ITPNT-RVN2429225; 2018ITPNT-RVN2401031; 2018ITPNT-RVN2401175; 2018ITPNT-RVN2399436; 2018ITPNT-RVN2401299; 2018ITPNT-RVN2400716; 2018ITPNT-RVN2399220; 2018ITPNT-RVN2407434; 2018ITPNT-RVN2406529; 2018ITPNT-RVN2407182; 2018ITPNT-RVN2406963; 2018ITPNT-RVN2406721; 2018ITPNT-RVN2406372; 2018ITPNT-RVN2407031; 2018ITPNT-RVN2406992; 2018ITPNT-RVN2406654; 2018ITPNT-RVN2406514; 2018ITPNT-RVN2406363; 2018ITPNT-RVN2407075; 2018ITPNT-RVN2406958; 2018ITPNT-RVN2406445; 2018ITPNT-RVN2406925; 2018ITPNT-RVN2406916; 2018ITPNT-RVN2406381; 2018ITPNT-RVN2407382; 2018ITPNT-RVN2406949; 2018ITPNT-RVN2430045; 2018ITPNT-RVN2430030; 2018ITPNT-RVN2429863; 2018ITPNT-RVN2430219; 2018ITPNT-RVN2433659; 2018ITPNT-RVN2433164; 2018ITPNT-RVN2433574; 2018ITPNT-RVN2433661; 2018ITPNT-RVN2433134; 2018ITPNT-RVN2433074; 2018ITPNT-RVN2433393; 2018ITPNT-RVN2433452; 2018ITPNT-RVN2432740; 2018ITPNT-RVN2433072; 2018ITPNT-RVN2389105; 2018ITPNT-RVN2388811; 2018ITPNT-RVN2389193; 2018ITPNT-RVN2388860; 2018ITPNT-RVN2388885; 2018ITPNT-RVN2389074; 2018ITPNT-RVN2404123; 2018ITPNT-RVN2404338; 2018ITPNT-RVN2404232; 2018ITPNT-RVN2404271; 2018ITPNT-RVN2403947; 2018ITPNT-RVN2404006; 2018ITPNT-RVN2404285; 2018ITPNT-RVN2428493; 2018ITPNT-RVN2429080; 2018ITPNT-RVN2428830; 2018ITPNT-RVN2429222; 2018ITPNT-RVN2400093; 2018ITPNT-RVN2400324; 2018ITPNT-RVN2400258; 2018ITPNT-RVN2399641; 2018ITPNT-RVN2406970; 2018ITPNT-RVN2406601; 2018ITPNT-RVN2407021; 2018ITPNT-RVN2406492; 2018ITPNT-RVN2407362; 2018ITPNT-RVN2407346; 2018ITPNT-RVN2407044; 2018ITPNT-RVN2407238; 2018ITPNT-RVN2407388; 2018ITPNT-RVN2406568; 2018ITPNT-RVN2407162; 2018ITPNT-RVN2406460; 2018ITPNT-RVN2407310; 2018ITPNT-RVN2406879; 2018ITPNT-RVN2406835; 2018ITPNT-RVN2406685; 2018ITPNT-RVN2407280; 2018ITPNT-RVN2406943; 2018ITPNT-RVN2406583; 2018ITPNT-RVN2429948; 2018ITPNT-RVN2430324; 2018ITPNT-RVN2430323; 2018ITPNT-RVN2430527; 2018ITPNT-RVN2430626; 2018ITPNT-RVN2430641; 2018ITPNT-RVN2430426; 2018ITPNT-RVN2430276; 2018ITPNT-RVN2430694; 2018ITPNT-RVN2429864; 2018ITPNT-RVN2430015; 2018ITPNT-RVN2381685; 2018ITPNT-RVN2381650; 2018ITPNT-RVN2382166; 2018ITPNT-RVN2381944; 2018ITPNT-RVN2381633; 2018ITPNT-RVN2406059; 2018ITPNT-RVN2405382; 2018ITPNT-RVN2406035; 2018ITPNT-RVN2406076; 2018ITPNT-RVN2405473; 2018ITPNT-RVN2405282; 2018ITPNT-RVN2405698; 2018ITPNT-RVN2405291; 2018ITPNT-RVN2390748; 2018ITPNT-RVN2391401; 2018ITPNT-RVN2391017; 2018ITPNT-RVN2391392; 2018ITPNT-RVN2391711; 2018ITPNT-RVN2391600; 2018ITPNT-RVN2391043; 2018ITPNT-RVN2390768; 2018ITPNT-RVN2391209; 2018ITPNT-RVN2391002; 2018ITPNT-RVN2390909; 2018ITPNT-RVN2391734; 2018ITPNT-RVN2391717; 2018ITPNT-RVN2391084; 2018ITPNT-RVN2391135; 2018ITPNT-RVN2387064; 2018ITPNT-RVN2387574; 2018ITPNT-RVN2432305; 2018ITPNT-RVN2431964; 2018ITPNT-RVN2431535; 2018ITPNT-RVN2431254; 2018ITPNT-RVN2380864; 2018ITPNT-RVN2390108; 2018ITPNT-RVN2389697; 2018ITPNT-RVN2390239; 2018ITPNT-RVN2390267; 2018ITPNT-RVN2389598; 2018ITPNT-RVN2390712; 2018ITPNT-RVN2389571; 2018ITPNT-RVN2390146; 2018ITPNT-RVN2389807; 2018ITPNT-RVN2389745; 2018ITPNT-RVN2430029; 2018ITPNT-RVN2430471; 2018ITPNT-RVN2430563; 2018ITPNT-RVN2381756; 2018ITPNT-RVN2381931; 2018ITPNT-RVN2382315; 2018ITPNT-RVN2381622; 2018ITPNT-RVN2405961; 2018ITPNT-RVN2405963; 2018ITPNT-RVN2405835; 2018ITPNT-RVN2406155; 2018ITPNT-RVN2405476; 2018ITPNT-RVN2405612; 2018ITPNT-RVN2406064; 2018ITPNT-RVN2406147; 2018ITPNT-RVN2405525; 2018ITPNT-RVN2405345; 2018ITPNT-RVN2405813;~~
Project #69	Build new substation and add new 14.4 MVAR capacitor bank at the Lakeview 69 kV bus	Build new Lakeview 69kV Substation New 14.4 MVAR (7.2 x 2) capacitor bank at the Lakeview 69 kV bus	SD SD	$ 5,617,000	Lakeview_Cap_Bank.idv	2018ITPNT-RVN2406999; 2018ITPNT-RVN2407234; 2018ITPNT-RVN2406479; 2018ITPNT-RVN2406947; 2018ITPNT-RVN2407465; 2018ITPNT-RVN2387336; 2018ITPNT-RVN2387027; 2018ITPNT-RVN2387313; 2018ITPNT-RVN2387635; 2018ITPNT-RVN2405401; 2018ITPNT-RVN2400790; 2018ITPNT-RVN2400674; 2018ITPNT-RVN2399845; 2018ITPNT-RVN2400130; 2018ITPNT-RVN2400062; 2018ITPNT-RVN2404047; 2018ITPNT-RVN2404273; 2018ITPNT-RVN2404066; 2018ITPNT-RVN2402193; 2018ITPNT-RVN2402796; 2018ITPNT-RVN2402471; 2018ITPNT-RVN2403198; 2018ITPNT-RVN2402728; 2018ITPNT-RVN2402869; 2018ITPNT-RVN2403131; 2018ITPNT-RVN2382489; 2018ITPNT-RVN2408387; 2018ITPNT-RVN2381671; 2018ITPNT-RVN2381655; 2018ITPNT-RVN2408819; 2018ITPNT-RVN2382131; 2018ITPNT-RVN2409254; 2018ITPNT-RVN2389975; 2018ITPNT-RVN2389976; 2018ITPNT-RVN2431784; 2018ITPNT-RVN2431305; 2018ITPNT-RVN2431575; 2018ITPNT-RVN2432235; 2018ITPNT-RVN2406575; 2018ITPNT-RVN2407296; 2018ITPNT-RVN2406826; 2018ITPNT-RVN2407112; 2018ITPNT-RVN2406795; 2018ITPNT-RVN2386929; 2018ITPNT-RVN2387583; 2018ITPNT-RVN2387548; 2018ITPNT-RVN2387322; 2018ITPNT-RVN2405848; 2018ITPNT-RVN2405283; 2018ITPNT-RVN2405456; 2018ITPNT-RVN2405759; 2018ITPNT-RVN2405380; 2018ITPNT-RVN2406150; 2018ITPNT-RVN2400693; 2018ITPNT-RVN2399733; 2018ITPNT-RVN2399205; 2018ITPNT-RVN2400668; 2018ITPNT-RVN2404658; 2018ITPNT-RVN2404548; 2018ITPNT-RVN2404511; 2018ITPNT-RVN2404231; 2018ITPNT-RVN2402992; 2018ITPNT-RVN2402391; 2018ITPNT-RVN2403207; 2018ITPNT-RVN2402466; 2018ITPNT-RVN2402708; 2018ITPNT-RVN2402424; 2018ITPNT-RVN2403015; 2018ITPNT-RVN2408984; 2018ITPNT-RVN2381590; 2018ITPNT-RVN2381943; 2018ITPNT-RVN2382218; 2018ITPNT-RVN2389647; 2018ITPNT-RVN2431343; 2018ITPNT-RVN2432265; 2018ITPNT-RVN2407704; 2018ITPNT-RVN2407856; 2018ITPNT-RVN2407823; 2018ITPNT-RVN2407788; 2018ITPNT-RVN2430558; 2018ITPNT-RVN2392321; 2018ITPNT-RVN2392331; 2018ITPNT-RVN2392196; 2018ITPNT-RVN2392295; 2018ITPNT-RVN2392102; 2018ITPNT-RVN2392047; 2018ITPNT-RVN2392346; 2018ITPNT-RVN2433374; 2018ITPNT-RVN2433519; 2018ITPNT-RVN2433349; 2018ITPNT-RVN2433432; 2018ITPNT-RVN2433466; 2018ITPNT-RVN2409661; 2018ITPNT-RVN2388895; 2018ITPNT-RVN2408595; 2018ITPNT-RVN2429332; 2018ITPNT-RVN2429214; 2018ITPNT-RVN2428555; 2018ITPNT-RVN2428944; 2018ITPNT-RVN2431205; 2018ITPNT-RVN2431515; 2018ITPNT-RVN2431725; 2018ITPNT-RVN2431489; 2018ITPNT-RVN2431459; 2018ITPNT-RVN2407792; 2018ITPNT-RVN2407816; 2018ITPNT-RVN2407702; 2018ITPNT-RVN2407861; 2018ITPNT-RVN2407952; 2018ITPNT-RVN2407749; 2018ITPNT-RVN2407827; 2018ITPNT-RVN2430546; 2018ITPNT-RVN2430613; 2018ITPNT-RVN2392324; 2018ITPNT-RVN2392108; 2018ITPNT-RVN2433654; 2018ITPNT-RVN2432752; 2018ITPNT-RVN2432784; 2018ITPNT-RVN2388788; 2018ITPNT-RVN2409126; 2018ITPNT-RVN2388341; 2018ITPNT-RVN2429134; 2018ITPNT-RVN2428957; 2018ITPNT-RVN2428782; 2018ITPNT-RVN2429135; 2018ITPNT-RVN2429310; 2018ITPNT-RVN2390847; 2018ITPNT-RVN2391322; 2018ITPNT-
Project #72	Reconductor 1.25 miles of the Nixa Downtown - Nixa Espy 69kV line	Reconductor 1.25 miles of the Nixa Downtown - Nixa Espy 69kV line	MO	$ 1,108,561	Nixa_Downtown-Nixa_Espy_Rebuild.idv	2018ITPNT-RON2432599; 2018ITPNT-RON2432497; 2018ITPNT-RON2429531; 2018ITPNT-RON2429727
Project #73	Construct a new substation at McDowell. Connect 230 kV and 115 kV systems at Exell with a new 230/115 kV transformer	Build new McDowell 230 kV Substation New 230/115 kV Transformer at McDowell	TX TX	$ 8,374,877 $ 4,829,305	McDowell_Transformer_and_Substation.idv	2018ITPNT-RVN2442336; 2018ITPNT-RVN2443140; 2018ITPNT-RVN2441450; 2018ITPNT-RVN2400399; 2018ITPNT-RVN2400419; 2018ITPNT-RVN2382044; 2018ITPNT-RVN2428941; 2018ITPNT-RVN2431355; 2018ITPNT-RVN2431840
	Replace Lawrence Hill 230/115 kV transformer	Replace Lawrence Hill 230/115 kV transformer	KS	$ 4,896,108		

*If blank, a cost estimate has not been received
**This project is subject to change based upon TWG action on 6/13/18

Final Reliability Assessment
After all upgrades have been identified and incorporated into the power flow models, a steady state N-1 contingency analysis will be conducted to identify any new potential violations. Staff will perform further analysis to determine solutions that address the new potential violations. These solutions will then be added to the final portfolio.

Revision Request Recommendation Report

RR #: 309	Date: 6/7/2018
RR Title: Separation of RC Area SOL Methodology from Planning Criteria	

SUBMITTER INFORMATION

Submitter Name: Neil Robertson	**Company:** SWPP
Email: nrobertson@spp.org	**Phone:** 501-614-3322

EXECUTIVE SUMMARY AND RECOMMENDATION FOR MOPC AND BOD ACTION

OBJECTIVE OF REVISION

Objectives of Revision Request:

Describe the problem/issue this revision request will resolve.

Currently, the SPP RC's document to satisfy the requirements of FAC-011-3 System Operating Limits Methodology for the Operations Horizon resides in SPP Planning Criteria as Section 7.3.1. This governing document structure can lead to confusion on the part of entities in the SPP RC Area currently and also entities that may become a part of the SPP RC Area in the future.

Describe the benefits that will be realized from this revision.

Removing Section 7.3.1 from the SPP Planning Criteria and creating a stand-alone document with the content of that section will provide the following benefits.

(1) Better align the language and it's intended purpose with recent changes to other governing documents

(2) Remove a dependency of the SPP RC function on the SPP Planning Criteria

(3) Make the pertinent information on the subject easier to locate and utilize

SPP STAFF ASSESSMENT

RR was submitted by SPP staff.

IMPACT

Will the revision result in system changes ☒ **No** ☐ **Yes**

Summarize changes:

Will the revision result in process changes? ☒ **No** ☐ **Yes**

Summarize changes:

Is an Impact Assessment required? ☒ **No** ☐ **Yes**

If no, explain: Proposed changes consist of relocating the location of the language and a number of grammatical clarifications

Estimated Cost: N/A	**Estimated Duration:** N/A
Primary Working Group Score/Priority: N/A	

SPP DOCUMENTS IMPACTED

☐ **Market Protocols**	**Protocol Section(s):**	**Protocol Version:**
☒ **Operating Criteria**	**Criteria Section(s):** 3	**Criteria Date:** 5/30/2018

☒ **Planning Criteria**	**Criteria Section(s):** 7	**Criteria Date:** 10/9/2017
☐ **Tariff**	**Tariff Section(s):**	
☐ **Business Practice**	**Business Practice Number:**	
☐ **Integrated Transmission Planning (ITP) Manual**	**Section(s):**	
☐ **Revision Request Process**	**Section(s):**	
☐ **Minimum Transmission Design Standards for Competitive Upgrades (MTDS)**	**Section(s):**	
☐ **Reliability Coordinator and Balancing Authority Data Specifications (RDS)**	**Section(s):**	
☐ **SPP Communications Protocols**	**Section(s):**	

WORKING GROUP REVIEWS AND RECOMMENDATIONS
List Primary and any Secondary/Impacted WG Recommendations as appropriate

Primary Working Group: ORWG	**Date: 5/30/2018** **Action Taken: Approved as Modified**
Secondary Working Group: RCWG	**Date: 6/7/2018** **Action Taken: Approved as Modified** **Abstained: 1 – Flatridge 2**
Secondary Working Group: TWG	**Date: 6/13/2018** **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
Secondary Working Group: SAWG	**Date: 6/27/2018** **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
Secondary Working Group: RTWG	**Date: 6/28/2018** **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
MOPC	**Date: Tentative July 2018** **Action Taken:** **Abstained:** **Opposed:**

Reasons for Opposition:	
BOD/Member Committee	**Date: Tentative July 2018** **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
COMMENTS	
Comment Author: Mark Eastwood (SPRM)	
Date Comments Submitted: 5/11/2018	
Description of Comments: City Utilities of Springfield, Missouri (SPRM) agrees with the objective of this revision request and supports efforts by SPP Staff to ensure the SOL development requirements are in the appropriate governing document. Even though the objective of this revision request isn't necessarily to modify existing language, the SPP Membership would benefit from a clear and consistent methodology to ensure all reliability limits are known and respected in the operations horizon. Therefore, SPRM would appreciate consideration of the suggested edits below to further clarify the requirements.	
Status: The majority of SPRM's comments were incorporated in concept in the version of the language approved by ORWG. Mark Eastwood supported the approval of Ron Gunderson's comments due to the fact that both sets of comments represented mostly the same concepts.	
COMMENTS	
Comment Author: Ron Gunderson (NPPD)	
Date Comments Submitted: 5/21/2018	
Description of Comments: NPPD agrees with the objective of this revision request and supports efforts by SPP Staff to better align SPP governing documents with the requirements of FAC-011-3 System Operating Limits Methodology for the Operations Horizon. NPPD has proposed mostly grammatical and clean-up changes to the existing language in the attached redlines below. One substantive change involves the use of the term violation or SOL exceedance in the operations planning horizon. Studies identify potential exceedances and are not actual exceedances. The proposed language in the redlines reflects this philosophy.	
Status: Comments were incorporated in the version of the language approved by ORWG.	
PROPOSED REVISION(S) TO SPP DOCUMENTS	
Market Protocols	

SPP Tariff (OATT)

SPP Operating Criteria

3.4 SPP Reliability Coordinator Area SOL Methodology

The *SPP RC Area SOL Methodology* document serves to meet the NERC Reliability Standards that require an SOL methodology for the SPP RC Area. Applicable entities in the SPP RC Area shall meet the requirements defined in the *SPP RC Area SOL Methodology* document, which can be found on the SPP website.

SPP Planning Criteria

SPP Business Practices

Integrated Transmission Planning (ITP) Manual

Revision Request Process

Minimum Transmission Design Standards for Competitive Upgrades (MTDS)

Reliability Coordinator and Balancing Authority Data Specifications (RDS)

SPP Communications Protocols

SPP Reliability Coordinator Area SOL Methodology (New Stand-Alone Document)

1.1 Methodology for the Determination of Operating Horizon SOLs

SPP's Methodology designates System Operating Limits (SOLs) in the Operating Horizon to consist of defined ~~flowgate~~Flowgate limits, limits defined in operating guides, and limits designated by agreement between the RC and TOP to prevent other reliability concerns such as instability. SPP respects all BES Facility Ratings in both Real-Time Assessments and through Operational Planning Analysis. SPP primarily controls the BES using both permanent and temporary ~~flowgate~~Flowgates per defined congestion management processes. SPP also controls the BES using coordinated operating plans or operator actions in specific situations in the absence of a ~~flowgate~~Flowgate. During the time a ~~flowgate~~Flowgate or an operating guide is being created, SPP shall issue Operating Instructions to implement manual actions as deemed necessary by the Reliability Coordinator to control the BES and operate within SOLs.

1) TOPs shall develop, at minimum, ~~thermal~~ SOLs that respect all BES Facility Ratings in coordination with the SPP RC. In addition, SOLs may be developed based on ~~transient stability ratings, voltage stability ratings, system voltage limits, and/or~~ other operating criteria.

2) SOLs shall not exceed Facility Ratings. SOLs equal applicable Facility Ratings unless additional studies have established a lower limit based on other operational issues such as transient, dynamic and voltage stability, etc. The Facility Ratings used in the Operating Horizon or Real-Time Horizon may be higher or lower than the Facility Ratings used in the Planning Horizon. All Facility Ratings shall be calculated in accordance with the appropriate Transmission Owner's Facility Rating methodology. Ratings that have been adjusted must be coordinated so that the impacted operating entities are aware of the duration that the adjusted rating may be used.

3) Including anticipated system topology, generation dispatch, and load levels, SOLs shall be determined per this SOL methodology and based on results of system studies as described below.

4) Pre-contingency and first contingency studies will be conducted to identify ~~Facility Rating~~potential SOL exceedances for current and next day.

5) Voltage stability and angular stability issues are studied as deemed necessary by operator and engineer experience and engineering judgment to identify stability SOLs.

6) As deemed necessary by study results, an operating guide to aid operators in mitigating potential SOL exceedances may be produced. These guides may be temporary or permanent, depending whether the ~~violation~~potential SOL exceedance is due to a short-term outage, seasonal loading issues, etc. At a minimum, this operating guide will include:

    a. Statement of type(s) of ~~limit~~ potential SOL exceedances revealed by study (voltage/thermal/stability)

    b. Applicable dates

    c. Available/recommended mitigation methods, including generation redispatch (maximum MW and/or minimum Mvar generation), transmission reconfiguration, reclosing reconfiguration, load shedding, and Transmission Loading Relief (TLR).

7) Identified SOLs are screened to compile a list of potential IROLs per the following criteria:

    a. Potential IROLs will be investigated when a contingency analysis highlights a thermal overload in excess of 120% of the SOL of the monitored ~~facilit~~Facility.

    b. Potential IROLs will also be investigated when a contingency analysis highlights an under-voltage condition characterized by bus voltages of less than 90% across three or more BES ~~facilit~~Facilities. The potential IROL condition will be reviewed further by evaluating the system response to the loss of the ~~facilit~~Facility with the SOL expected to be exceeded. The original potential IROL condition will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing loss of the ~~facilit~~Facility with the SOL exceedance results in another BES ~~facilit~~Facility being overloaded to greater than 120% of its SOL or

three or more additional BES ~~facilit~~Facilities with bus voltages in the area experiencing projected post-contingency voltages less than 90% of nominal voltage, unless there are studies or system knowledge that the SOL is not an IROL.

8) The IROL TV is 30 minutes unless studies dictate a shorter time.

9) Remedial Action Schemes (RAS's) are allowed to prevent prolonged undervoltage and to preserve system voltage and machine stability.

1.2 SOL Provisions

1) In the pre-contingency state, the BES shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage, and stability limits. In determining SOLs, the BES condition used shall reflect future system conditions with all ~~facilit~~Facilities operated in their normal operating condition.

2) Following single contingencies as defined in (a), (b), and (c) below, the system shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage, and stability limits; and Cascading Outages or uncontrolled separation shall not occur.

    a. Single-line-to-ground or three-phase fault (whichever is more severe), with normal clearing, on any faulted generator, line, transformer, or shunt device.

    b. Loss of any generator, line, transformer, or shunt device without a Fault.

    c. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

3) In determining the system's response to a single Contingency starting with all ~~facilit~~Facilities operated in their normal operating condition, the following shall be acceptable:

    a. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. System reconfiguration should be implemented to minimize the interruption of electric supply to the extent possible.

    b. System reconfiguration through manual or automatic control or protection actions.

4) To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

5) Starting with all ~~facilit~~Facilities operated in their normal operating condition and following any of the multiple contingencies identified in Reliability ~~s~~Standard TPL-001~~3~~ the system shall demonstrate transient, dynamic and voltage stability; all ~~facilit~~Facilities shall be operating within their ~~facilit~~Facility ratings and within their thermal, voltage and stability limits; and ~~c~~Cascading or uncontrolled separation shall not occur.

6) In determining ~~the system's response to any of~~ the applicable multiple contingencies identified by the Planning Coordinator ~~in Reliability sStandard TPL-0013~~, in addition to the actions identified in (a) and (b) above, the following shall be acceptable:

   a. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or curtailment of contracted firm electric power transfers. System reconfiguration should be implemented to minimize the interruption of electric supply to the extent possible.

1.3 System Modeling and Contingency Definition

1) All offline models shall be based on a coordinated model of the Eastern Interconnect and any necessary ~~facilit~~Facilities in other Interconnections. The model shall include all Transmission Operator (TOP) Areas within the SPP RC footprint as well as ~~facilit~~Facilities in adjacent TOP Areas that have been determined to have impact on the SPP RC footprint.

2) The model shall include all non-radial ~~facilit~~Facilities within the BES. Loads served over radial lines may be modeled as aggregate at the delivery bus. Distribution capacitors can be modeled as aggregate at a load bus.

3) The online model used by the SPP EMS application is constructed from data in the offline model (PSS/E).

~~1)~~4) At a minimum the contingency list used in the operating horizon shall include all non-radial BES transmission lines and transformers and all generators rated 150~~300~~MW and above. Additional contingencies will be included as provided by other applicable registered entities

2018 SPP Flowgate Assessment Report

June 13, 2018

SPP Engineering and Operations

SPP Southwest Power Pool

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Purpose

This annual assessment was performed to fulfill requirements set forth in the MOD-030-3 NERC standard, requirement R2, pursuant to SPP Planning Criteria 6.4.2 requirements. This process assesses the adequacy of the existing list of flowgates and thereby recommends necessary additions, deletions, and modifications. Although transfer values are involved, this process is not intended to produce any viable ATC values for commercial activity or otherwise.

Overview

The process commenced with the development of a scope document and updates to the subsystem files. Transmission Operators provided updates to their participation points for both imports and exports. If updates were not received from Transmission Operators, the subsystem files were updated per SPP Planning criteria 6.4.2.3. Monitor and contingency files were also updated. Transfer directions were the set of all possible commercial paths. Transfer capabilities were calculated using PTI PSS®MUST software[1].

An AC First Contingency Incremental Transfer Capability (FCITC) analysis was performed to determine the top three limits per transfer path per season. The results were then filtered and narrowed down to a list of potential flowgate candidates for addition and removal. Specifically, a potential flowgate candidate that showed up as a top constraint was considered for addition. Conversely, any existing flowgate that did not show up as one of the top three limiting constraints was considered for removal. The potential flowgate candidates for addition and removal were then sent to SPP Operations for review. Any flowgate removal candidates that had been subjected to a Congestion Management Event (CME) or Transmission Loading Relief (TLR) in the last 12 months were not removed. The flowgate candidate list with SPP Operations comments was then posted to a secure site (GlobalScape) for Transmission Operators to review. If a member requested that a flowgate candidate for removal be kept, the justification was reviewed and factored into the decision to keep a flowgate. All of the FCITC results were posted on a secure site (GlobalScape) for Transmission Operators to review.

SPP staff and Transmission Operators provided comments on the proposed flowgate candidates for addition and removal. Remedial Action Schemes (RAS) and Transmission Operating Guides (TOGs) were taken into consideration during this review process. Any potential new flowgates that were deemed invalid due to the existence of a RAS or TOG were removed from the list of proposed flowgate additions. After reviewing all feedback, the updated flowgate list was then presented to the Transmission Working Group (TWG) for approval of flowgate candidates for addition and removal. Transmission Reliability Margin (TRM) values were calculated on the updated list of SPP flowgates. The TRM calculation process is completed prior to flowgates being added to the master flowgate list. The approved potential flowgates

[1] The appendix section contains the TWG approved scope document which details the assumptions used in the analysis.

for addition and removal were also presented to the Operations Reliability Working Group (ORWG).

The TWG and ORWG both approved a recommendation to add 47 new flowgates to the SPP system, and a recommendation to remove 52 existing flowgates from the SPP system. The details are summarized in the “Results” section below.