2018 ITPNT

2018 Integrated Transmission Planning Near-Term Scope

November 8, 2017
Engineering

Southwest Power Pool

Revision History

Date or Version Number	Author	Change Description	Comments
02/06/2016	SPP Staff	Initial Draft	
03/22/2017	SPP Staff	Changes to Scenario 5 modeling of DC Ties and added Sensitivity case	DC Tie changes requested by NPPD, WAPA, and Basin
03/30/2017	SPP Staff	Updates to table describing models	
04/03/2017	TWG	TWG Approval	
04/11/2017	MOPC	MOPC Approval	
04/25/2017	SPP Board of Directors	Board Approval	
7/19/2017	TWG	Added the consideration 69 kV violations caused by additional contingencies in the development of solutions	
8/7/2017	SPP staff/Board of Directors	Addition of Scenario 5 summer models and removal of firm transmission service for solar from Scenario 5 light load.	
8/15/2017	TWG	TWG Approval	
9/20/2017	TWG	Schedule changes made based upon TWG decision to rebuild models and extend study deadline	

10/17/2017	MOPC	Addition of high voltage Brookline need for study consideration	Verify need based upon approved persisten operational needs criteria
11/8/2017	TWG	TWG approval of Brookeline need addition	

Table of Contents

Overview

This document presents the scope and schedule of work for the 2018 Integrated Transmission Planning (ITP) Near-Term Reliability Assessment. This document will be reviewed by the Transmission Working Group (TWG) with the expectation of approvals from the Market Operations and Policy Committee (MOPC) and the Board of Directors (Board) in April 2017. The assessment begins in April 2017 and is a 12-month study scheduled to be finalized in April 2018.

Objective

The ITP process is an iterative three-year planning process performed in accordance with Attachment O of the SPP Open Access Transmission Tariff (SPP OATT) that includes 20-Year, 10-Year and Near Term Assessments (ITP20, ITP10 and ITPNT, respectively) designed to identify transmission solutions that address both near-term and long-term transmission needs. The ITP20 is conducted over the first half of the three-year cycle and the ITP10 is conducted over the second half of the three-year cycle. The ITPNT is an assessment that is performed annually in order to evaluate the reliability of the SPP transmission system in the near-term planning horizon, collaborate on the development of improvements with stakeholders, and assess system upgrades at all applicable voltage levels required in the near-term planning horizon to meet reliability criteria. The 2018 ITPNT's primary focus is identifying solutions required to meet SPP reliability. The process includes coordination of transmission plans with the ITP20, ITP10, Aggregate Study, and Generator Interconnection processes.

The 2018 ITPNT study will generate an effective near-term plan for the SPP Regional Transmission Organization (RTO) planning region by identifying solutions to reliability criteria exceedances for system intact and contingency conditions. These reliability criteria exceedances are identified through evaluation of the following:

- NERC Reliability Standard TPL-001-4 Planning "P1 and P2.1" events comprised of software generated and SPP member-submitted contingencies
- NERC Reliability Standard TPL-001-4 Planning events that do not allow for Non-Consequential Load Loss (NCLL) or Interruption of Firm Transmission Service (IFTS)
- Developing mitigation plans, including transmission upgrades, to meet the region's needs and maintain SPP and local reliability/planning standards

The 2018 ITPNT study horizon will include modeling of the transmission system for five years (i.e., 2022). In order to comply with FERC's Order 1000, SPP developed the Transmission Owner Selection Process, as outlined in Attachment Y of the SPP Tariff. In accordance with Attachment O, Section III.8.b, SPP shall notify stakeholders of potential transmission needs and provide a transmission planning response window of thirty (30) days during which any stakeholder may propose a Detailed Project Proposal (DPP).

The SPP ITP process is open and transparent and allows for stakeholder input through the FERC Order 1000 and Order 890 processes. The Transmission Working Group (TWG) will have opportunities to review components of the 2018 ITPNT process, which includes but is not limited to the following items: model development, reliability analysis, transmission plan development, seams impacts, and the 2018 ITPNT assessment report. In addition, SPP will present the ITPNT Project Plan at the SPP transmission planning summits as an opportunity for SPP stakeholders to provide feedback. SPP will also coordinate the study results with first-tier neighbors.

Data inputs

SPP will analyze 2019 and 2022 models in the 2018 ITPNT for the following seasons: 2019 summer peak, 2019 winter peak, 2022 light load, 2022 summer peak, and 2022 winter peak. A total of 15 model scenarios plus 1 DC Tie Sensitivity case will be analyzed as part of the 2018 ITPNT Assessment. The modeling set is summarized in the table below.

Description	Scenario 0	Scenario 5	Base Reliability Scenario	SPP BA
Year 2 (2019)	Summer Peak Winter Peak	Summer Peak Winter Peak*	Summer Peak	Summer Peak Winter Peak
Year 5 (2022)	Summer Peak Winter Peak Light Load	Summer Peak Winter Peak* Light Load	Summer Peak	Summer Peak Winter Peak Light Load

* DC Tie Sensitivity Cases

A. *Load*

The load values and locations for the steady state analysis will be provided through the Model Development Working Group (MDWG) model building process[1]. The load will represent each individual load balancing area's peak conditions per season (*i.e.*, non-coincident conditions for the SPP region).

B. *Generation Resources*

Existing generating resources will be represented in the power flow models taking into account planned retirements. New generating resources included in the power flow models will be limited to resources with a FERC-filed Interconnection Agreement (IA) not on suspension. Generation capacity is included in the assessment if there is an executed transmission service agreement. Exceptions to these qualifications are addressed in the ITP Manual.

C. *Model Topology*

The topology used to account for the transmission system, excluding generation, will be the current transmission system and the following transmission upgrades: SPP upgrades that have been approved for construction, SPP Transmission Owner's planned (zonal sponsored) upgrades, and first-tier entities' planned upgrades (first-tier entities listed below). The model development processes for SPP MDWG account for long-term transmission facility outages of 6 months or longer as forecasted by each member transmission owner.

First-tier entities include the following:

- Associated Electric Cooperative, Inc. (AECI)
- Alliant Energy West (ALTW)
- Ameren Missouri (AMMO)
- Central Iowa Power Cooperatives (CIPC)

[1] SPP MDWG Model Development Procedure Manual

- Central Louisiana Electric Company (CLEC)
- Dairyland Power Cooperative (DPC)
- Entergy Arkansas (EAI)
- Entergy Electric System (EES)
- Great River Energy (GRE)
- Mid-American Energy (MEC)
- Minnkota Power Corporation (MPC)
- Montana-Dakota Utilities Co. (MDU)
- Otter Tail Power Company (OTP)
- Saskatchewan Power Co. (SPC)
- Xcel Energy North (XEL)

D. *Scenario Modeling*

To account for both confirmed long-term transmission service as well as the Integrated Marketplace, SPP will develop multiple scenario models representing individual load modeling areas (Scenario 0, Scenario 5, and Base Reliability) as well as SPP acting as a single Balancing Authority (SPP BA).

Scenario 0:
Scenario 0 (S0) is built similar to the MDWG models but removes any non-firm transmission service, removes generation without signed interconnection agreements. Renewable resources are dispatched at output levels provided by members not exceeding expected firm service amounts.

Scenario 5:
Scenario 5 (S5) sets all renewable resources to maximum firm transmission service amounts with the exception of solar in light load seasons[2]. All reservations between companies are set to maximum firm service on a pro rata basis as limited by load.

Base Reliability Scenario:
The Base Reliability scenario models assume expected long-term firm transmission service usage levels. Renewable resources are dispatched at each facility's latest 5-year average for the SPP coincident summer peak[3], not to exceed each facility's firm service amount. In the event that 5 years of historical renewable resource output data is unavailable, SPP will follow the TWG-approved data replacement methodology.

SPP Balancing Authority:

For each SPP Balancing Authority (SPP BA) model, SPP will be modeled as a single Balancing Authority with interchange modeled across the SPP seams. The SPP BA scenario will leverage the SPP portion of the NERC Book of Flowgates updated with information from the 2017 Flowgate Assessment and latest ITP10 economic generator data. To capture future constraints that are not currently in the NERC Book of Flowgates due to seasonal topology changes and load growth, a constraint assessment will be completed to determine if any constraints, 69 kV or above, should be added, removed, or modified before the Security Constrained Unit Commitment/Security Constrained Economic Dispatch (SCUC/SCED) is developed. The latest available economic data from the ITP processes will be used to perform the constraint assessment. The updated

[2] Light load is defined as an April minimum load level that pinpoints a condition such as Sunday morning in April, hour ending 5:00am, thus typically falls during an hour before sunrise.
[3]SPP coincident summer peak equals the highest demand including transmission losses for energy measured over a one clock hour period.

constraint list will be reviewed and approved by the TWG before being used to create the SPP BA scenario models. The Eastern Interconnect generation outside of SPP will remain unchanged.

Operational Model for Voltage Evaluation at Brookline
If a persistent operational need is identified at Brookline using the criteria described in the Steady State Assessment section, an operational model will be created that defines the system conditions when the operational need is observed.

E. ***DC Ties***

Scenario 0 (All seasons):
All dc tie set points will be scheduled the same as the MDWG models not exceeding firm service. If firm service is exceeded, the DC Ties will be reduced to the highest capacity of firm service for the season.

Scenario 5 (All seasons):
All firm transmission service is maxed for the following ties:
- Lamar – All service is maxed, SPP is importing
- Welsh – All service is maxed, SPP is exporting
- Oklaunion – Only SPP exporting service is maxed
- Sidney – All service is maxed in West to East bias, SPP is importing
- Stegall – All service is maxed in West to East bias, SPP is importing
- Rapid City – All service is maxed West to East bias, SPP is importing
- Miles City – All service is maxed West to East bias, SPP is importing

Scenario 5 Sensitivity Case (Winter):
All firm transmission service is maxed for the following ties:
- Lamar – All service is maxed, SPP is importing
- Welsh – All service is maxed, SPP is exporting
- Oklaunion – Only SPP exporting service is maxed
- Sidney – All service is maxed in East to West bias, SPP is exporting
- Stegall – All service is maxed in East to West bias, SPP is exporting
- Rapid City – All service is maxed East to West bias, SPP is exporting
- Miles City – All service is maxed East to West bias, SPP is exporting

Base Reliability Scenario (Summer season):
All DC Tie set points will be scheduled the same as the MDWG models not exceeding firm service. If firm service is exceeded, the dc ties will be reduced to the highest capacity of firm service for the season.

SPP Balancing Authority (All seasons):
All DC Tie set points will be scheduled the same as the MDWG models not exceeding firm service. If firm service is exceeded, the dc ties will be reduced to the highest capacity of firm service for the season.

F. ***Demand Response***

Demand response will be incorporated into the models through lower load and capacity forecasts, which is developed as described in subsection A above.

Analysis

A. ***Steady State Needs Assessment***

The steady state assessment will use the following models: 2019 summer peak and winter peak, 2022 light load, summer peak and winter peak using individual load modeling area's dispatch. SPP will also use SPP BA models of these same seasons. A system intact and N-1 contingency analysis (TPL-001-4 P1 and P2.1 events) will be performed for the peak and off-peak cases for facilities 60 kV and above in SPP and facilities 100 kV and above in first-tier. All facilities 60 kV and above in SPP and 100 kV and above in first-tier will be monitored. SPP will use engineering judgment to resolve non-converged cases. If these cases cannot be solved, the potential violations will be posted in the potential needs list specifying the result of the analysis (*e.g.*, voltage collapse). SPP's Planning Criteria will be utilized to determine if a potential Regional Reliability violation will be considered as a need. SPP's Planning Criteria is as follows:

- Thermal violations: Loadings observed greater than 100% of Rate A for system intact conditions or greater than 100% of Rate B for emergency situations
- Voltage Violations: Per Unit values less than 0.95 or greater than 1.05 for system intact conditions or less than 0.90 or greater than 1.05 for emergency situations

The following model areas will be monitored at 1.1 pu for voltage:
- Basin Electric Power Cooperative (Area 659)
- Nebraska Public Power District[3] (Area 640)
- Omaha Public Power District[4] (Area 645)
- Western Area Power Administration (Area 652)

An abbreviated steady state assessment will be performed on the Winter DC Tie Sensitivity Case for 2022 only. As part of this analysis only facilities that do not meet SPP Criteria or more stringent local planning criteria for Western Area Power Authority, Basin Electric Power Cooperative, and Nebraska Public Power District will be identified for potential inclusion in the posted list of needs. Engineering judgment will be use to evaluate the impacts the change in DC Tie bias has on the observed violations for inclusion in the list of potential needs posted for submission of solutions. Additional contingencies, described in Section C below, will not be considered in the DC Tie Sensitivity Case contingency analysis.

Brookline High Voltage Need Evaluation

Staff will apply the voltage criteria approved by the TWG for the development of persistent operational needs to determine if the high voltage issues at the Brookline station still exist. If the Brookline high voltage still meets the requirements, it will be included in the posted Needs Assessment for solution submissions during the DPP Window. The criteria for determination of a persistent operational need is system reconfiguration required 10% of the time due to high or low voltage issues observed.

B. ***Local Planning Criteria***

All Local Planning Criteria (LPC) will be collected from SPP TOs before the start of the 2018 ITPNT assessment. Auxiliary files will be updated with the latest TO LPC information. SPP will request the TOs

[4] Monitored at 1.05 pu for voltage, but allows up to 1.1 pu if system adjustments can be made to return voltage to within normal limits

validate the updated auxiliary files which will be used during the base case and contingency analysis. The LPC potential violations will be posted on a secure website.

C. ***Additional Contingencies***

All P0, P1, and P2.1 events are evaluated as part of the normal SPP contingency analysis process. The table below identifies the additional events that will be evaluated for potential violations. SPP facilities 69 kV[5] and above will be monitored as part of this analysis.

Event Category	Voltage Level	Description
P2	EHV[6]	P2.2: Single (Bus section)
	EHV	P2.3: Single (Internal Breaker Fault [non-Bus-tie breaker])
P3	EHV, HV[7]	P3.1: Multiple (Gen., System Adj., Gen.)
	EHV, HV	P3.2: Multiple (Gen., System Adj., Transmission Circuit)
	EHV, HV	P3.3: Multiple (Gen., System Adj., Transformer)
	EHV, HV	P3.4: Multiple (Gen., System Adj., Shunt Device)
	EHV, HV	P3.5: Multiple (Gen., System Adj., Single Pole of a DC Line)
P4	EHV	P4.1: Multiple[8] (Fault[9] on Generator, Stuck Breaker)
	EHV	P4.2: Multiple[8] (Fault[9] on Transmission Circuit, Stuck Breaker)
	EHV	P4.3: Multiple[8] (Fault[9] on Transformer[10], Stuck Breaker)
	EHV	P4.4: Multiple[8] (Fault[9] on Shunt, Stuck Breaker)
	EHV	P4.5: Multiple[8] (Fault[9] on Bus Section, Stuck Breaker)
P5	EHV	P5.1: Multiple[8] (Fault on Generator, Primary relay failure on Generator)
	EHV	P5.2: Multiple[8] (Fault on Transmission Circuit, Primary relay failure on Transmission Circuit)
	EHV	P5.3: Multiple[8] (Fault on Transformer[10], Primary relay failure on Transformer)
	EHV	P5.4: Multiple[8] (Fault on Shunt, Primary relay failure on Shunt)
	EHV	P5.5: Multiple[8] (Fault on Bus Section, Primary relay failure on Bus Section)

These additional events will be analyzed on Year 5, cases for the 2022 summer peak (Scenario 0) and 2022 light load (Scenario 0) models only.

Season	Scenario
ITPNT 2022SP	Scenario 0
ITPNT 2022L	Scenario 0

[5] NERC Standard TPL-001 only requires facilities included in the BES, generally 100 kV and above, to be analyzed
[6] EHV denotes facilities 300 kV and above
[7] HV denotes facilities greater than 100 kV but less than 300 kV
[8] All elements in this contingency must be at or above the associated Voltage level
[9] Non-Bus-tie Breaker
[10] Low side voltage

All potential violations resulting from these additional events will be posted for solution development described in Section D. Any project that may be required only to address the need for these additional events will be staged in 2022 during the respective season the project is needed. For example, a project needed to mitigate needs resulting from the additional contingencies described in Section C in a light load model would be given a Need Date of 4/1/2022.

D. ***Solution Development***

SPP will develop and analyze solutions for the 2018 ITPNT portfolio. The solutions will consist of DPPs and other projects submitted for the 2018 ITPNT, planned SPP upgrades approved for construction, planned LPC solutions provided by Transmission Owners (TOs), solutions developed by SPP staff, and any other solutions proposed by SPP stakeholders. As part of solution development, 69 kV violations caused by the additional contingencies described in Sub-Section C of the Analysis section will be used as supplemental information when selecting solutions to address 100 kV+ violations caused by those same contingencies.

Solutions will be accepted for the DC Tie Sensitivity Case posted potential violations for development of the most cost beneficial project to mitigate any impacts of modifying the DC Tie bias. The TWG will make a recommendation to the MOPC and Board on project(s) that solve these observed potential violation(s) from the DC Tie Sensitivity Case, by leveraging historical data and engineering judgment. Solutions approved from the DC Tie Sensitivity case will leverage analysis from the 2019 Winter DC Tie Sensitivity case for staging purposes only.

Solutions driven only by scenario 5 summer peak needs will be further evaluated for additional merits that would support the need for the project. This may include each solution’s ability to allow additional allocation of Auction Revenue Rights (ARR), ability to resolve current or projected market congestion, or potential adjusted production cost benefits. The details of these additional evaluations will be discussed with the TWG and other applicable stakeholder groups prior to potential recommendation of a solution for construction. Projects driven from this analysis will be explicitly identified and approved independently by the Board of Directors.

Solutions for the Brookline high voltage need will be evaluated against the operational model where the issue is observed to ensure the best solution is recommended.

E. ***Shunt Reactive Requirements Assessment***

A line-end reactive requirements analysis will be performed if any 300 kV and above upgrades are identified as solutions and presented in the 2018 ITPNT Project Plan. This analysis will be performed on the 2022 light load models by opening each end of the new line to identify preliminary shunt reactive needs. The analysis will provide the amount of MVARs needed to maintain both 1.05 pu and 1.1 pu voltage at both ends of the new line. After performing the light load analysis, the reactor will be studied under steady state summer peak conditions to determine if switched capability is needed. This analysis will provide an indicative amount of reactive needs before design level studies are completed. This analysis will be completed with the entire 2018 ITPNT Project Plan.

F. ***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.

G. ***Short-Term Reliability Projects***

After the 2018 ITPNT has been completed, SPP staff will give a full determination of any Short-term reliability projects. These projects will be separately identified and posted with an explanation of the reliability violations and system conditions for which there is a time-sensitive need. There will be a thirty (30) day comment period as required in Section I.3.c of Attachment Y of the SPP Tariff. Projects that meet this criteria will not be considered competitive under the SPP's rules related to FERC Order 1000 upon approval by the Board.

Seams

In the development of the 2018 ITPNT Project Plan, SPP will review expansion plans of neighboring utilities and RTOs and include first-tier entities' planned projects in the 2018 ITPNT models. Based upon that review, staff may take into account other external plans. The models used in the 2018 ITPNT incorporate the latest data from the neighboring utilities and RTOs through the Multiregional Modeling Working Group (MMWG) model development process. In addition to the MMWG model development process, SPP will coordinate with first-tier neighbors to receive any additional model updates.

SPP will also coordinate the results of the steady state assessment with first-tier entities, highlighting needs relevant to the seam with that neighbor. As part of this coordination, SPP will also encourage first-tier neighbors to participate in the solutions development portion of the study by submitting potential projects to be considered.

Cost-effectiveness testing will be performed for all potentially beneficial seams projects. This additional cost-effectiveness testing will identify the level of cost sharing that will make a seams project more viable than an SPP regionally-implemented solution.

SPP will coordinate the potential impacts of the 2018 ITPNT with neighboring entities. This coordination is conducted in accordance with the relevant Joint Operating or Seams agreements. In the absence of such an agreement, SPP will contact the relevant entities to discuss the potential impacts on their systems.

Schedule

The study will begin in April 2017 and be completed by July 2018. The estimated study timeline is as follows:

Item	Approval By	Start Date	Completion Date
Scoping	TWG	January 2017	October 2017
Model Development (S0, S5, Base & SPP BA)	TWG	February 2017	October 2017
Needs Assessment	TWG	October 2017	December 2017
DPP Response Window	TWG	January 2018	February 2018
Solution Development	TWG	February 2018	May 2018
Draft Portfolio	TWG	March 2018	June 2018
Final Reliability Assessment	TWG	June 2018	
Review report	TWG	June 2018	July 2018
Final report with recommended Project Portfolio	TWG	July 2018	July 2018
	MOPC	July 2018	

Deliverables

The results of the 2018 ITPNT assessment will be compiled into a report detailing the findings and recommendations of SPP Staff.

Changes in Process and Assumptions

In order to protect against changes in process and assumptions that could present a significant risk to the completion of the ITPNT, any such changes must be vetted. If TWG votes on any process steps or assumptions to be used in the study, those assumptions will be used for the 2018 ITPNT. Changes to process or assumptions recommended by stakeholders must be approved by the TWG. This process will allow for changes if they are deemed necessary and critical to the ITPNT, while also ensuring that changes, risks, benefits, schedule impacts, and cost of those changes, will be fully vetted and discussed.