2017 ITPNT

2017 Integrated Transmission Planning Near-Term Scope

June 15, 2016
Engineering

SPP Southwest Power Pool

Revision History

Date or Version Number	Author	Change Description	Comments
01/26/2016	Staff	Initial Draft	Reviewed by the TWG on 02/23/2016
03/15/2016	Staff	Add language based on 02/23/2016 TWG feedback	Added language to show how dc ties are currently modeled
06/09/16	Staff	Incorporate TWG, MOPC / Board feedback	Added language to address the evaluation of TPL-001-4 events that do not allow for Non-Consequential Load Loss, or Curtailment of Firm Transmission Service. Added language to address the Scenario 5 method incorporating thoughts of the TPITF

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Overview

This document presents the scope and schedule of work for the 2017 Integrated Transmission Planning (ITP) Near-Term Reliability Assessment. This document will be reviewed by the Transmission Working Group (TWG) beginning February 2016, with the expectation of approvals from the Market Operations and Policy Committee (MOPC) and the Board of Directors (BOD) in April 2016. The assessment begins in April 2016 and is a 12-month study scheduled to be finalized in April 2017.

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 2017 ITPNT's primary focus is identifying solutions required to meet the reliability criteria defined in OATT Attachment O, Section III.6. The process includes coordination of transmission plans with the ITP20, ITP10, Aggregate Study, and Generator Interconnection processes.

The 2017 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 2017 ITPNT study horizon will include modeling of the transmission system for five years (*i.e.*, 2021). This five year look allows the necessary lead time such that the Notification to Construct (NTC) issuance can be provided in time for project owners to complete their projects by the identified Need Date. 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 identified transmission Needs and provide a transmission planning response window of thirty (30) days during which any stakeholder may propose a Detailed Project Proposal (DPP). SPP shall track each DPP and retain the information submitted pursuant to Attachment O, Section III.8.b (i).

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 and vet components of the 2017 ITPNT process, which includes but is not limited to the following items: model development, reliability analysis, transmission plan development, seams impacts, and the 2017 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

For the 2017 ITPNT, SPP will consider power flow models with individual load modeling areas, as well as models with the SPP Balancing Authority (SPP BA Scenario). SPP will analyze 2018 and 2021 models in the 2017 ITPNT for the following seasons: 2018 summer peak, 2018 winter peak, 2021 light load, 2021 summer peak, and 2021 winter peak. A total of 15 model scenarios will be analyzed as part of the 2017 ITPNT Assessment. The SPP BA model will include a wind dispatch with a bid cap based upon wind generation past performance max output. The modeling set is summarized in the table below.

Description	Scenario 0	Scenario 5	SPP BA
Year 2 peak	ITPNT 2018SP ITPNT 2018WP	ITPNT 2018SP ITPNT 2018WP	ITPNT 2018SP ITPNT 2018WP
Year 5 peak	ITPNT 2021SP ITPNT 2021WP	ITPNT 2021SP ITPNT 2021WP	ITPNT 2021SP ITPNT 2021WP
Year 5 off-peak	ITPNT 2021L	ITPNT 2021L	ITPNT 2021L

A. ***Load***

The load density and distribution 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). Resource obligations will be determined for the footprint taking into consideration what load is industrial (non-scalable) and residential, commercial and agricultural (scalable) type loads.

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 not on suspension or resources with an executed Service Agreement. 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 line outages of 6 months or longer as forecasted by each member transmission owner.

[1] SPP MDWG Model Development Procedure Manual

First-tier entities include the following:

- Associated Electric Cooperative, Inc. (AECI)
- Alliant Energy West (ALTW)
- Ameren Missouri (AMMO)
- Central Louisiana Electric Company (CLEC)
- Dairyland Power Cooperative (DPC)
- Entergy Arkansas (EAI)
- Entergy Electric System (EES)
- Great River Energy (GRE)
- Mid-American Energy (MEC)
- Montana-Dakota Utilities Co. (MDU)
- Otter Tail Power Company (OTP)
- Saskatchewan Power Co. (SPC)
- Xcel Energy North (XEL)

D. ***Transmission Service***

To account for confirmed long-term transmission service SPP will develop scenario models representing individual load modeling areas. The first scenario (S0) is built similar to the MDWG models but removes any non-firm transmission service, removes generation without signed interconnection agreements, removes topology that is projected or unbudgeted and incorporates transactions provided by members. Wind generation is accredited according to SPP Criteria. The second scenario (S5) sets all wind generation to maximum firm service, then all reservations between companies are set to maximum firm service as much as load will allow on a pro rata basis.

E. ***DC Ties***

Scenario 0:
All dc tie set points will be scheduled the same as the MDWG models if 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. If an area has shortfall, available service across the dc tie may be used as well.

Scenario 5:
All service is maxed for the following ties:

- Lamar – All service is maxed in scenario 5, SPP is importing
- Welsh – All service is maxed in scenario 5, SPP is exporting
- Oklaunion – Only SPP exporting service is maxed
- Sidney – All service is maxed in scenario 5, SPP is importing

For new dc ties:

- Stegall – Historically flows West to East, biased so SPP is importing
- Rapid City – Historically flows West to East, biased so SPP is importing
- Miles City – All service is maxed up until WAPA has shortfall

F. ***SPP Balancing Authority***

In order to account for the impacts of the Integrated Marketplace on the SPP footprint, an SPP Balancing Authority (SPP BA) scenario model will be developed as part of the 2017 ITPNT Assessment. For each SPP BA scenario SPP will be modeled as a single Balancing Authority with interchange modeled across the SPP seams. The SPP BA scenario will utilize the SPP portion of the NERC Book of Flowgates updated with information from the 2016 Flowgate Assessment, 2017 ITPNT transmission topology and latest ITP10 economic generator data. The goal will be to attain a security-constrained unit commitment and economic dispatch (SCUC/SCED) for each year and season identified as part of the 2017 ITPNT Assessment. In an effort 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 should be added, removed, or modified before the SCUC/SCED is developed. The updated constraint list will be reviewed and approved by the TWG before being applied to the SPP BA scenario models.

Making use of the economic data from the latest ITP10, TARA PowerGem will be used to perform an AC security constrained economic dispatch on the SPP footprint to deliver the most economical power around SPP base case and N-1 constraints 69kV and above excluding invalid constraints. An N-1 contingency analysis described in subsection A (Steady State Assessment) of the Analysis section will then be performed on each SPP BA power flow model. The Eastern Interconnect generation outside of SPP will remain unchanged.

G. ***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 Assessment***

The steady state assessment will use the following models: 2018 summer peak and winter peak, 2021 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. An 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 Needs list specifying the result of the analysis (*e.g.*, voltage collapse).

B. ***NERC Reliability Standard TPL-001-4***

SPP will identify potential violations using the NERC Reliability Standard TPL-001-4 Planning "P0" and "P1" events, comprised of software-generated and SPP member-submitted contingencies. Additionally, all NERC TPL-001-4 standard Table 1 planning events that do not allow for non-consequential load loss or interruption of firm transmission service will be evaluated for potential violations. Some P0 and P1 events are evaluated as part of the normal SPP contingency analysis process and are classified as NCLL and IFTS events.

TPL-001-4 Event Category	Voltage level	Description	Interruption of Firm Transmission Allowed	Non-Consequential Load Loss Allowed
P0	EHV, HV	P0: No contingency	No	No
P1	EHV[2], HV[3]	P1.1: Single (Generator)	No	No
	EHV, HV	P1.2: Single (Transmission Circuit)	No	No
	EHV, HV	P1.3: Single (Transformer[4])	No	No
	EHV, HV	P1.4: Single (Shunt)	No	No
	EHV, HV	P1.5: Single (Single Pole of a DC line)	No	No
P2[5]	EHV, HV	P2.1: Single (No fault line section)	No	No
	EHV	P2.2: Single (Bus section)	No	No
	EHV	P2.3: Single (Internal Breaker Fault [non-Bus-tie breaker])	No	No
P3	EHV, HV	P3.1: Multiple (Gen., System Adj., Gen.)	No	No
	EHV, HV	P3.2: Multiple (Gen., System Adj., Transmission Circuit)	No	No
	EHV, HV	P3.3: Multiple (Gen., System Adj., Transformer)	No	No

[2] EHV denotes facilities 300 kV and above
[3] HV denotes facilities greater than 100 kV but less than 300 kV
[4] Low side voltage
5 P2-P5 events are new to the ITP process for the 2017 ITPNT Assessment

TPL-001-4 Event Category	Voltage level	Description	Interruption of Firm Transmission Allowed	Non-Consequential Load Loss Allowed
	EHV, HV	P3.4: Multiple (Gen., System Adj., Shunt Device)	No	No
	EHV, HV	P3.5: Multiple (Gen., System Adj., Single Pole of a DC Line)	No	No
P4	EHV	P4.1: Multiple[6] (Fault[7] on Generator, Stuck Breaker)	No	No
	EHV	P4.2: Multiple[2] (Fault[3] on Transmission Circuit, Stuck Breaker)	No	No
	EHV	P4.3: Multiple[2] (Fault[3] on Transformer[1], Stuck Breaker)	No	No
	EHV	P4.4: Multiple[2] (Fault[3] on Shunt, Stuck Breaker)	No	No
	EHV	P4.5: Multiple[2] (Fault[3] on Bus Section, Stuck Breaker)	No	No
P5	EHV	P5.1: Multiple[2] (Fault on Generator, Primary relay failure on Generator)	No	No
	EHV	P5.2: Multiple[2] (Fault on Transmission Circuit, Primary relay failure on Transmission Circuit)	No	No
	EHV	P5.3: Multiple[2] (Fault on Transformer[1], Primary relay failure on Transformer)	No	No
	EHV	P5.4: Multiple[2] (Fault on Shunt, Primary relay failure on Shunt)	No	No
	EHV	P5.5: Multiple[2] (Fault on Bus Section, Primary relay failure on Bus Section)	No	No

For the purpose of the 2017 ITPNT analysis, NCLL and IFTS will not be allowed for the events listed above. However, footnotes 9 and 12 of the TPL-001-4 Standard do allow either or both NCLL or IFTS for certain events in this table. These incremental NCLL and IFTS planning events will be analyzed on Year 5, Scenario 0 cases for the 2021 summer peak and 2021 light load models only.

Scenario 0
ITPNT 2021SP
ITPNT 2021L

All potential violations resulting from these additional events will be posted for solution development described in Section D. Any project that may be required to meet TPL-001-4 compliance with only "P2-P5" events will be staged in 2021 during the respective season the project is needed. For example, a project needed to meet TPL compliance for a "P2-P5" planning event in a light load model would be given a Need Date of 4/1/2021.

6 All elements in this contingency must be at or above the associated Voltage level

7 Non-Bus-tie Breaker

C. ***Scenario 5 Needs Coupling Criteria***

SPP will take all potential violations resulting from the Scenario 5 summer peak models and will compare the thermal loading or per unit voltage values of the same monitored element, contingent element pair in the respective SPP BA summer peak model to determine if it qualifies to be included in the Needs assessment list. The following criteria will be applied during the evaluation of potential violations resulting from Scenario 5 summer peak models for inclusion into the Needs assessment list:

Model	Thermal Criteria	Voltage Criteria
Scenario 5 Summer Peak (Basecase)	> 100%	< 0.95
SPP BA Summer Peak (Basecase)	> 100%	< 0.95
Scenario 5 Summer Peak (N-1)	> 100%	< 0.90
SPP BA Summer Peak (N-1)	> 95%	< 0.92

D. ***Solution Development***

SPP will perform a Needs assessment and analyze solutions to develop the 2017 ITPNT plan. The solutions will consist of DPPs submitted for the 2017 ITPNT, planned SPP upgrades approved for construction, planned company-specific reliability planning solutions provided by Transmission Owners (TOs), solutions developed by SPP staff, and any other solutions proposed by SPP stakeholders.

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 2017 ITPNT Project Plan. This analysis will be performed on the 2021 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 2017 ITPNT Project Plan.

F. ***Stability Analysis***

SPP will not perform stability analysis as part of the 2017 ITPNT Assessment.

G. ***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 upgrades that address the new potential violations. These upgrades will then be added to the final portfolio.

Seams

In the development of the 2017 ITPNT Project Plan, SPP will review expansion plans of neighboring utilities and RTOs and include first-tier entities' planned projects in the 2017 ITPNT models. Based upon that review, staff may take into account other external plans. The models used in the 2017 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 2017 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.

Study Process

1. The resource additions and retirements, load profiles, and transmission service inclusion processes will be developed through stakeholder reviews.

2. The TWG/MDWG will oversee the development of the models that incorporate the assumptions developed in step #1 above, including review of data and results. A model review will be conducted by MDWG and TWG to verify the models before analysis starts.

3. An initial steady state analysis will be performed using applicable planning standards on power flow models that represent the applicable load profiles and generation dispatch per year and season. The assessment will be for the horizon years one (1) through five (5). All facilities 60 kV and above in SPP and all facilities 100 kV and above in SPP's first tier will be monitored.

    a. With input from stakeholders, 60 kV and above solutions will be developed to mitigate potential violations. Solutions will be coordinated with the Aggregate (AG) and Generation Interconnection (GI) Study processes for the SPP planning region.

    b. A check will be performed to determine if projects identified in the ITP10 assessments will eliminate or defer any projects identified in the 2017 ITPNT.

4. A final reliability assessment will be performed, repeating the steps above on the identified solutions to validate the solutions and check for new potential violations. Staff will perform further analysis to determine upgrades that address the new potential violations. These upgrades will be incorporated into the final portfolio.

5. Short-term reliability 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.

Schedule

The study will begin in February 2016 and be completed by April 2017. The estimated study timeline is as follows:

Item	Approval By	Start Date	Completion Date
Scoping	TWG	January 2016	March 2016
Model Development (S0, S5 & SPP BA)*	TWG	March 2016	July 2016
Needs Assessment	TWG	June 2016	September 2016
DPP Response Window	TWG	September 2016	October 2016
Solution Development	TWG	September 2016	November 2016
Draft Portfolio	TWG	December 2016	February 2017
Final Reliability Assessment	TWG	March 2017	
Review report	TWG	March 2017	April 2017
Final report with recommended Project Plan	TWG	March 2017	April 2017
	MOPC	April 2017	

*Note: Model Development for the SPP BA Scenario includes TWG review of constraints to be used in the models

Deliverables

The results of the 2017 ITPNT study 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 2017 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, and benefits of those changes, will be fully vetted and discussed.