Southwest Power Pool

JOINT TRANSMISSION & ECONOMIC STUDIES WORKING GROUP MEETING

February 15, 2017

Embassy Suites Riverwalk – San Antonio, TX

• M I N U T E S •

Agenda Item 1 – Administrative Items

Call to Order, Introductions

TWG Chair Travis Hyde and ESWG Chair Alan Myers called the meeting to order. The following members were in attendance (Attachment 1a, 1b, 1c – Joint Attendance, Joint Attendance – Phone, Joint Attendance – WebEx) or represented by proxy (Attachment 1d – Proxies):

Travis Hyde (Chair), Oklahoma Gas & Electric
Daniel Benedict, Independence Power & Light
Scott Benson, Lincoln Electric System
John Boshears, City Utilities of Springfield
Richard Dahl, Missouri River Energy Services
John Fulton, Southwestern Public Service Company
Joe Fultz, Grand River Dam Authority
Shaun Golden, Western Farmers Electric Cooperative
Jody Holland, South Central MCN
John Knofczynski, East River Electric Power Cooperative
Randy Lindstrom, Nebraska Public Power District
Jim McAvoy, Omaha Municipal Power Authority
Nathan McNeil, Westar Energy, Inc.
Nate Morris, Empire District Electric
Michael Mueller, Arkansas Electric Cooperative Corporation
Alan Myers, ITC Great Plains
Gayle Nansel, Western Area Power Administration
John Payne, Kansas Electric Power Cooperative
Chris Pink, Tri-State Generation & Transmission
Scott Rainbolt, American Electric Power
Jason Shook, GDS Associates representing ETEC
Matthew Stoltz, Basin Electric Power Cooperative
Josh Verzal, Omaha Public Power District
Harold Wyble, Kansas City Power & Light

Alan Myers (Chair), ITC Great Plains
Al Tamimi, Sunflower Electric Power Cooperative
Bennie Weeks, Southwestern Public Service Company
Bethany King, Empire District Electric
Don Le, NextEra Energy Transmission
Gayle Nansel, Western Area Power Administration
Jeremy Severson, Basin Electric Power Cooperative
Jody Holland, South Central MCN
Jon Iverson, Omaha Public Power District
Kurt Stradley, Lincoln Electric System
Leon Howell, Oklahoma Gas & Electric
Michael Massery, Arkansas Electric Cooperatives
Michael Watt, Oklahoma Municipal Power Authority

Natasha Henderson, Golden Spread Electric Cooperative
Pat McCool, Kansas City Power & Light
Randy Collier, City Utilities of Springfield, MO
Tim Owens, Nebraska Public Power District

Kirk and Kelsey informed the Chairs both groups had attained a quorum.

Receipt of Proxies
Kirk identified the following proxies:

- Scott Rainbolt (AEP) proxy or Matt McGee
- Jody Williams (SCMCN) proxy for Noman Williams (SCMCN)

Kelsey identified no proxies.

Agenda Item 2 – Consent Agenda

Alan and Travis asked the respective working groups for approval of the items (Attachment 2 – ITP Manual Task Force draft manual) listed on the consent agenda. Neither group expressed concerns with any of the items.

Motion: The ESWG unanimously voted to approve the Consent Agenda items

Motion: The TWG unanimously voted to approve the Consent Agenda items

Agenda Item 3 – ITP Manual Task Force Update

Michael Wegner, ITP Manual Task Force Chair, updated the group on the progress of the ITP Manual Task Force. Michael provided information on the progress of the group as well as the upcoming meeting schedule.

Agenda Item 4 – Lubbock Exit Study

Charles Hendrix, SPP staff, discussed the SPP/ERCOT City of Lubbock Exit study scope (Attachment 3a, 3b – Lubbock Exit Study, SPP ERCOT Lubbock Study Scope document). Charles spoke about the reliability and economic assessments at high level. The TWG and ESWG had no questions for Charles.

Agenda Item 5 – ITP Scope Standardization

Resource Siting Plan
Chris Jamieson, SPP staff, discussed the high level concepts (Attachment 4a – Siting Presentation) of the Siting Whitepaper he is currently drafting.

Constraint Assessment
Kirk presented to the members the Constraint Assessment (Attachment 4b – Constraint Assessment Presentation) methodologies and processes. Kirk presented multiple methods for identifying constraints for inclusion in the event file used to develop the Economic Model including: screening contingencies, automatically selecting constraints from the reliability hours, incorporating 69 kV constraints, assessing TPL planning events, and reclassifying needs. Staff received consensus agreement from the TWG and ESWG on a few items. The members agreed to staff recommendations on including constraints from reliability hours automatically and which TPL-001-4 planning events staff might use to develop constraints. Both working groups voted and agreed to allow the temporary flowgates on the 69 kV system as potential constraints.

Motion: Jody Holland made a motion for the ESWG to accept staff's recommendation to potentially allow for temporary flowgates on the 69 kV system to be included as a constraint. Kurt Stradley seconded the motion, which passed unanimously

Motion: Jody Holland made a motion for the TWG to accept staff's recommendation to potentially allow for temporary flowgates on the 69 kV system to be included as a constraint. Jason Shook seconded the motion, which passed with one abstention from Randy Lindstrom (NPPD).

The members were unsure of staff's recommendation to allow the reclassification of Needs from one category to another and asked staff to seek clarity from SPP Legal and come back later with a recommendation.

Resource Addition Request /Resource Waiver Process

Kelsey Allen, SPP staff, discussed the process (Attachment 4c – Resource Addition/Waiver Process) for including generation resources in the Base Reliability, SPP BA Economic and SPP BA Powerflow models. The members agreed with staff's approach and suggested staff move forward to the language development process.

DC to AC Model Conversion

Kelsey then moved onto the DC to AC Model Conversion process (Attachment 4d – DC/AC Conversion) that staff performs to build the snapshot powerflow model representative of the peak and off-peak hours selected for the reliability assessment in the ITP10. Neither group had issues with staff's model conversion process.

Transmission Topology Modeling

Kelsey also discussed SPP's recommendation for modeling transmission topology between the Base Reliability model and SPP BA Powerflow models as well as nuances of the topology included in the economic models. Specifically the group discussed the inclusion of transmission outages longer than 6 months in the Base Reliability model as required by TPL-001-4, and not including those outages in the SPP BA Powerflow models.

Agenda Item 6 – 2017 ITP10 Update

Juliano Freitas, SPP staff, discussed the outcome of the 2017 ITP10 at the SPP Board of Director's meeting indicating that staff would continue to evaluate the 345 kV line from Potter – Tolk the Texas Panhandle. Staff plans to work with both groups to scope the study as well as review results and seek feedback.

Respectfully Submitted,

Kirk Hall
TWG Secretary

Kelsey Allen
ESWG Secretary

SPP Southwest Power Pool

Phone Only (1 of 2)

Southwest Power Pool, Inc.

TWG/ESWG JOINT MEETING

February 15, 2017

Embassy Suites Riverwalk-Downtown – San Antonio, TX

• ATTENDANCE LIST •

Name	Company
Randy Collier	City Utilities of Springfield
Michael Massery	AECC
Bethany King	EMDE
Michael Watt	OMPA
John Iverson	OPPD
Heather Starnes	MJEMUC
Al Tamimi	Sunflower
Matt McGee	AEP
John Boshears	City Utilities of Springfield
Matthew Stoltz	Basin
Jody Holland	SC MCN
Harold Wyble	KCP+L
Ryan Yokley	Sunflower
Dan Lenihan	OPPD
Daniel Benedict	Independence P+L
Dana Parks	GRDA
Bill Young	NPRB
Joe Fultz	GRDA
Chris Pink	Tri-State G+T
Zac Hager	OGE

59 Al Tamimi
Alan Myers
Aravind Chellappa (SPS)
Ashley Swain
Ben Abing
Bethany King
Bill Leung (NPRB)
Bob Burner
Bret Toplyn (ABB)
Chenal WebEx
Chris Jamieson - SPP
Chris Matthes
chris pink
Dan Lenihan
Daniel Benedict (INDN)
Dona Parks (GRDA)
eric burkey
Harold Wyble (KCPL)
Heather Starnes (MJMEUC)
James Mitschke (OCC)
Jamie Hajek
Jason Mazigian
Jeremy Harris (Westar)
Jody Holland
Joe Fultz
John Boshears (SPRM)
John Fulton
Jon Iverson
Jon Shipman
Jonathan Hayes
Josh Verzal
Kevin Foflygen (SPRM)
Kirk Hall
Leon Howell
Liz Gephardt
Marisa Choate
Matt McGee
matthew stoltz
Michael Massery (AECC)
Michael Mueller
Michael Watt (OMPA)
Nigel Dunham
Nikki Roberts
Pat McCool
Randy Collier (CUS)
reene miranda
Ross Hohlt

Ryan Yokley
Sarah Pettus
Scott Benson (LES)
Steve Hardebeck-OG&E
Steve Hohman
Walt Cecil
Zac Hager

SPP Southwest Power Pool

Southwest Power Pool, Inc.

TWG/ESWG JOINT MEETING

February 15, 2017

Embassy Suites Riverwalk-Downtown – San Antonio, TX

• ATTENDANCE LIST •

Name	Company
Jayle Jansen	Western Area Power Admin
Jeremy Severson	Basin Electric Power Coop
Richard Dahl	Missouri River Energy Services
Kirk Hall	SPP
Travis Hyde	OG+E
Kelsey Allen	SPP
Alan Myers	ITC
Randy Lindstrom	NPPD
James Ging	Kansas Power Pool
Don Le	NEET
Jarrod Wolford	Northeast Texas Electric Coop
JASON SHOCK	GDS/ETEC
NATE MORRIS	EMPIRE DISTRICT
Pat McCool	KCP&L
JULIANO MARIAS	SPP
BRIAN JOHNSON	AEP
John Knofczynski	East River Electric

SPP Southwest Power Pool

Southwest Power Pool, Inc.

TWG/ESWG JOINT MEETING

February 15, 2017

Embassy Suites Riverwalk-Downtown – San Antonio, TX

• ATTENDANCE LIST •

Name	Company
Jim McAvoy	OMPA
Shaun Golden	WFEC
Scott Benson	LES
Tim Owens	NPPD
KURT STRADLEY	LES
Nathan McNeil	Westar
Charles Hendrix	SPP
BENNIE WEEKS	Xcel Energy / SPS
Natasha Henderson	GSEC
Michael Wegner	ITC
John Payne	KEPCo
Josh Verzal	OPPD
Amber Gries	SPP
Jason Davis	SPP
CARLOS E. VALENCIA	SWPA
Scott Mijin	SWPA
Patrick West	SWPA
DAVID SARGENT	SWPA
Scott Rainbolt	AEP
JORDAN SCHMICK	XCEL/SPS

ITP MANUAL

Subtitle

Published on DATE

By AUTHOR/DEPARTMENT

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
02/3/2017	Communications Department	Document created	

CONTENTS

INTRODUCTION

PURPOSE

The SPP Open Access Transmission Tariff (OATT), Attachment O Section III.8.e, requires Southwest Power Pool, Inc. (SPP) to assess the cost effectiveness of proposed transmission projects in accordance with the Integrated Transmission Planning (ITP) Manual. This manual will outline the processes for the annual ITP process.

The ITP is a regional planning process built to leverage knowledge of the transmission system's reliability, public policy, compliance, and economic needs, as well as generation interconnection and transmission service request impacts in order to develop a cost-effective transmission portfolio over a 10-year planning horizon. Utilizing a common set of foundational modeling assumptions as the starting point for all planning studies within the planning cycle, the model builds for all reliability, public policy, compliance, and economic studies will be developed to produce needs assessments for 2, 5, and 10-year planning horizons. System needs resulting from generation interconnection and transmission service requests will be identified within the currently established timelines for those processes. However, the evaluation of transmission service needs and associated projects will be coordinated with those identified in the 10-year horizon regional planning process to facilitate continuity in the overall transmission expansion plan. This targeted approach is both forward-looking and proactive, designing a cost-effective and responsive transmission network which adheres to the ITP principles (listed in section 1.B), while following the FERC "Nine Transmission Principles".[1]

Analyses will be performed following the adoption of the study assumptions and will focus on cost-effectiveness and flexibility, while taking into account reliability, public policy, compliance, and economic considerations in project or portfolio recommendations. In the assessment of a project or group of projects' performance, SPP will assess the project's ability to perform across multiple capacities, which may include:

- Performance across multiple futures
- Ability to solve multiple Need types
- Reliability impacts related to compliance with NERC Standard TPL-001-4
- Operational impacts

Cost-effective analysis is a form of economic analysis that allows for the most effective planning over a longer versus shorter-term time frame. The objective is to produce the most economical project planning over the longer-term horizon.

This manual includes standardized language detailing ITP study items that were reviewed by the appropriate stakeholder groups and approved by MOPC. This standardization will provide specific details around each scope item and eliminate the need for repetitive reviews and approvals in order to help facilitate the performance of an annual planning cycle. Stakeholders will retain the ability to request a modification of standardized scope items by utilizing the SPP Revision Request

[1] These FERC principles are coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning (congestion) studies, and cost allocation for new projects, as described more fully in Order 890, Final Rule, pages 245 – 323.

(RR) process as discussed in more detail below. An ITP study scope will be developed for items that will require stakeholder review and approval with each new study. The ITP manual, study scope, and RR process are described further in later sections of this manual.

OVERVIEW OF THE SPP ITP PROCESS

First paragraph here

INTRO TO ITP PROCESS

HISTORY OF THE ITP

ORGANIZATIONAL GROUP SUPPORT

TPITF

ITP PROCESS TODAY

USE OF STUDY TO SATISFY COMPLIANCE WITH NERC TPL-001-4

First paragraph here

ADDITIONAL PLANNING EVENTS EVALUATED

STUDY SCOPE DOCUMENT

In order to provide the appropriate context under which to assess the future performance of the existing transmission system and any needed improvements, certain assumptions and methodologies may change with each study cycle. Maintaining the ability to update these assumptions from study to study will provide the flexibility needed for the transmission planning process. The Study Scope document describes those items that will require Stakeholder review and approval with each new study. Those Study Scope items will be approved by the appropriate working groups during the scope development phase at the beginning of each planning cycle.

MODEL DEVELOPMENT

COMMON SCENARIO PLANNING MODEL OVERVIEW

As previously discussed within this manual, the ITP process will be used to satisfy the planning requirements found in Attachment O of the SPP OATT, as well as some NERC Compliance requirements within NERC Standard TPL-001-4 (TPL) using a common planning model scenario (Base Reliability Model). This scenario will be built consistently with the information found in the following sections of this manual. Nine (9) total power flow models will be built using the

methodology of the common planning model. The table below describes the years and seasons that will be developed by SPP.

Year 2	Year 5	Year 10
Summer Peak	Summer Peak	Summer Peak
Winter Peak	Winter Peak	Winter Peak
Light Load	Light Load	Light Load

This model set will be utilized as the base model for transmission service and generator interconnection study processes. It is important to note, however, these base scenario models will be adjusted as necessary within each individual process to appropriately analyze and integrate transmission service requests or generator interconnection requests consistent with the SPP Tariff provisions and business practices that govern each process.

Information needed to construct the models will be provided by SPP members with appropriate review opportunities by SPP staff and stakeholders, prior to receiving final approval. These inputs, described in the following sections, include:

- Generation Resources
- Load Forecasts
- Definition of the SPP Footprint
- Topology
- Modeling of Firm-Transmission Service
- DC Tie Modeling
- DC Line Modeling
- Phase Shifting Transformers
- NTC Re-evaluation Requests

All data requests and review opportunities will be administered through the Model Development Working Group (MDWG) and Transmission Working Group (TWG), as appropriate.

Additionally, a short circuit model will be built for the short circuit assessment to meet short circuit analysis required in the TPL standard. This short circuit model will be built under the guidance of the Model Development Working Group (MDWG).

GENERATION

LOAD FORECASTS

The ITP process will require load forecasts for SPP members and non-members within the SPP footprint, as well as areas outside of the SPP footprint, for the corresponding study years. The load forecast will be submitted to the MDWG using the process described in the MDWG manual model building process.

The load will represent each individual load balancing area's peak conditions without losses per season (*i.e.*, non-coincident conditions for the SPP region).

FOOTPRINT

The modeling footprint includes the entire SPP region and nearby areas within the Eastern Interconnection. The non-SPP areas that may be modeled are AECI, Midwest ISO, and the western portions of PJM and SERC.

In the event of pending changes in the footprint of a region, additional areas may be added and additional sensitivities or scenarios may be studied in order to properly assess, anticipate, and understand the impact of such changes on the transmission needs of the SPP. These would be identified in the study scope.

RENEWABLE RESOURCES-LANGUAGE TO REFLECT ORDER 1000 REQUIREMENT

TOPOLOGY

SPP (Including Outages 6 Months or Greater)

Non-SPP

MODELING OF FIRM TRANSMISSION SERVICE

DC TIE MODELING

DC LINES MODELING

PHASE SHIFTING TRANSFORMERS

SPP BA ECONOMIC MODEL OVERVIEW

MARKET ASSUMPTIONS AND DATA

Market Structure

Futures Development

Due to the uncertainties involved in forecasting future system conditions, a number of diverse futures or scenarios are considered that take different assumptions into account. Consideration of multiple futures or scenarios provides for a transmission expansion plan that is sufficiently flexible to meet a variety of needs that may develop as economic, environmental, regulatory, public policy, and technological changes arise that affect the industry. The futures will be developed by the ESWG with input, if provided, from the Strategic Planning Committee (SPC) and subject to the approval of the MOPC.

Economic models will be developed for three study years (Years 2, 5, and 10). A single future will be developed for Year 2. It is assumed that multiple futures are not necessary for Year 2 due to the limited uncertainty in policy or other factors impacting the system that could be implemented in

such a short time frame. Up to three futures will be developed for Years 5 and 10, during the scoping of each successive annual assessment. The futures will consist of a reference case, as determined by the ITP study scope, along with one or two additional futures designed to assimilate expected or plausible future scenarios. Details around the reference case and the future case(s) will be included in the ITP study scope document. As a result, up to seven total economic models may be developed to support economic assessments.

Renewable Survey

Topology

DC Ties and Lines

Phase Shifting Transformers

Load and Energy Forecasts

Fuel Prices

Fuel price forecasts for the reference case future including natural gas, oil, uranium, and coal, including transportation costs, will be based upon the latest vendor data set.

Potential adjustments to the fuel prices for the non-reference case future(s) will be determined by the ESWG to appropriately reflect each future, and will be described in the ITP study scope document.

SCUC & SCED Analysis

An economic assessment will be performed to analyze congested facilities on the SPP transmission system. The economic needs of the system will be identified in order to develop a portfolio for each future. All of the economic system needs will be identified through the use of a Security Constrained Unit Commitment (SCUC)/Security Constrained Economic Dispatch (SCED) simulation that accounts for every hour of the study years. The SCUC/ SCED simulation requires a dual-optimization process. The first process is the SCUC. Here, the hourly least-cost combination of units that should be committed (turned on or off) is determined subject to unit-specific operational constraints (e.g., ramping, minimum output, min/max runtime, startup cost, etc.), and some critical location-specific transmission reliability constraints (e.g., must-run operational limits); but without explicit consideration of transmission grid operational costs.

The second process is the SCED solution of the units committed by the SCUC process. In the SCED process, the units are dispatched (exact unit output determined) in a least-cost manner subject to various transmission operational constraints (e.g., line thermal limits) and transmission reliability constraints (e.g., n-1 contingencies).

The SCUC and SCED model will solve using nodal Locational Marginal Prices (LMP), which will commit and dispatch the generation economically based on unit characteristics, load information, and transmission constraints. These analyses will determine potential issues including congestion, LMP variation, and trapped generation.

Hourly Load Shapes

Emission Prices

Emission price forecasts for the reference case future including, but not limited to, CO_2, SO_2, and NO_X will be based upon the latest vendor data set.

Potential adjustments to the emission prices for the non-reference case future(s) will be determined by the ESWG to appropriately reflect each future, and will be described in the ITP study scope document.

Hurdle Rates

Hurdle rates for all futures will be based upon the latest vendor data set. Potential adjustments to the hurdle rates will be determined by the ESWG, and will be described in the ITP study scope document.

Existing Generation

Must-Run Operational Limits

Renewable Pricing

RESOURCE PLAN

Renewable Resource Expansion Plan

Conventional Resource Expansion Plan

Resource Addition Requests

Resource Siting Plan

Conventional Siting

Wind Siting

Solar Siting

Generation Outlet Facilities

Constraint Assessment Methodology

SPP BA POWERFLOW MODEL OVERVIEW

GENERATION

TOPOLOGY (INCLUDES OUTAGES 6 MONTHS OR GREATER)

DC TIES AND LINES

PHASE SHIFTING TRANSFORMERS

LOAD FORECASTS

RESOURCE PLAN

Demand-side resources

GENERATOR OUTLET FACILITIES

DC/AC CONVERSION PROCESS

REACTIVE DEVICE SETTING ADJUSTMENTS

After the DC/AC conversion process is complete, an opportunity will be provided for staff and stakeholders to review the settings for transmission facilities that provide reactive support for the transmission system. Stakeholders will be asked to submit changes to set points for capacitors and reactors, tap changers for transformers, and remote buses and voltage schedules for generators and Static Var Compensators. These adjustments will improve the response of the transmission system under system intact and contingency conditions as well as provide confidence to both staff and

stakeholders that potential violations are realistic system conditions prior to the reliability needs assessment.

No topology changes will be accepted to correct the model. Any identified model corrections will be required to be submitted during the Detailed Project Proposal (DPP) window as outlined in Section 5.

Once all reactive device settings have been received, staff will apply the adjustments to the appropriate models before final posting and approval.

OPERATIONAL MODEL DEVELOPMENT

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ECONOMIC NEEDS ASSESSMENT

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ECONOMIC PROJECT SELECTION METHODOLOGY

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STAFF AND STAKEHOLDER ACCOUNTABILITY

REVISION REQUEST PROCESS
A request to make additions, deletions, revisions, or clarifications to this ITP Manual shall be made in accordance with the Revision Request Process[2].

ACCOUNTABILITY PROCESS
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APPENDICES

GLOSSARY
First paragraph here

BENEFIT METRICS
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[2] SPP Revision Requests


SPP
Southwest
Power Pool
HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.

Lubbock Exit Study

Compliance and Advanced Studies

Background

- Lubbock Power & Light (LP&L) announced in 2014 its intent to move its electric system (generation, transmission, distribution) from the Southwest Power Pool (SPP) to the Electric Reliability Council of Texas (ERCOT)
- July 19, 2016 – Public Utility Commission of Texas (PUCT) Chairman filed a memo addressing LP&L's move from SPP to ERCOT.
- Memo included a recommendation for analyses to be performed by SPP and ERCOT to determine potential impacts to customers in Texas
- ERCOT and SPP met and developed a scope, the highlights which follow.
- ERCOT and SPP will perform separate analyses. The analyses will be consistent and coordinated prior to release of results.

Assumptions

- Models
  - Reliability - 2021 Summer Peak and 2021 Light Load models from the 2017 ITPNT will be evaluated as a benchmark model (scenario 0 and scenario 5)
    - Models will be developed that remove NTCs that have not yet been placed in service.
  - Economic - 2020 and 2025 production costs models from the 2017 ITP10 reference case will be used
  - Models will be developed that have the LP&L system removed from SPP.
- Topology
  - Latest representation of the LP&L system as provided by LP&L will be used.
- Load Assumptions
  - Reliability – both Business as Usual (BAU) and High Growth forecast will be analyzed.
  - Economic – BAU will be used

Assumptions

- Generation
  - Reliability – Generation Assumption per ITP Planning Manual Section 3.3.1.2.
  - Economic – Generation Assumption per ITP10 reference case (Future 3)
  - Wind and Solar Profiles will be included in the production cost analysis.
  - LP&L generation will be modeled consistently with ERCOT
  - Consistent gas price with ERCOT
  - Wind and solar will be modeled as $0 marginal cost
  - Grid Switchers in the area will be modeled consistently with ERCOT.
  - Forced Outages –
    - SPP will perform with and without forced outages
    - ERCOT will perform without forced outages

Analysis

- Reliability
  - Contingency analysis will be performed.
  - Results for models with and without the LP&L system will be compared.
- Avoided and New Needs
  - NTCs that have not yet gone into service will be removed from the models that have LP&L removed.
  - Contingency analysis will be performed
  - Avoided needs will be evaluated
  - New needs will be evaluated
- Production Cost
  - Production cost analysis will be performed for models with and without the LP&L system.
  - Production costs for each will be calculated

Analysis

Analysis	LP&L in SPP	LP&L in ERCOT
Reliability	2021 LL and SP - (BAU & High Growth) - scenario 0 and 5 (8 models)	2021 LL and SP - (BAU & High Growth) - scenario 0 and 5 (8 models)
Avoided and New Needs (NTCs removed)		2021 LL and SP - (BAU & High Growth) - scenario 0 and 5 (8 models)
Production Cost	2020 and 2025 BAU (2 models)	2020 and 2025 BAU (2 models)

Additional Analysis

- Operations
  - Qualitative assessment by SPP of the operational impacts
- Ancillary Services
  - Qualitative assessment by SPP on the ancillary service impacts
- Congestion Rights
  - Qualitative assessment by SPP on the congestion rights impacts

SPP-ERCOT Coordinated Lubbock ERCOT Integration Study Scope

1. Overview

On July 19, 2016, Public Utility Commission of Texas (PUCT) Chairman Nelson filed a memo in docket 45633 addressing the proposed move of the Lubbock Power and Light (LP&L) system from the Southwest Power Pool (SPP) grid into the Electric Reliability Council of Texas (ERCOT) grid. Among other things the memo included a recommendation for analyses to be performed by SPP and ERCOT. This scope document details the studies to be performed to address the recommended analyses.

In order to accomplish the recommended analyses SPP and ERCOT will perform separate, but coordinated, studies. The studies will be performed such that the assumptions and methodologies used by SPP and ERCOT will be as consistent as reasonably possible, though it is understood that market and regulatory differences may prevent absolute consistency.

In June 2016 ERCOT filed its Lubbock Integration Study with the PUCT. This study was narrowly focused on identifying the best and most cost effective way to integrate the LP&L system into the ERCOT grid. The study concluded that "Option 4ow" was the preferred integration alternative should the LP&L system move to ERCOT. The analysis outlined in this study scope builds upon this previous study and will provide further analysis of the impacts of Lubbock Power and Light load and generating resources moving to ERCOT or remaining in SPP.

2. Assumptions

The following transmission topology assumptions shall be used:

2.1. SPP will use the following base cases as the basis for its analysis:
   a. 2021 summer peak scenario 0 and scenario 5 models from the 2017 Integrated Transmission Planning-Near Term (ITPNT) study
   b. 2021 light load scenario 0 and scenario 5 models from the 2017 ITPNT
   c. 2020 and 2025 production cost models from 2017 Integrated Transmission Planning-10 Year Assessment (ITP10) reference case

2.2. ERCOT will use the following base cases as the basis for its analysis:
   a. The latest WFW 2021 summer peak case from the 2016 Regional Transmission Plan (RTP) will be used for reliability analysis and system strength analysis.
   b. The latest 2026 UPLAN model from the 2016 Long-Term System Assessment (LTSA) Current Trends scenario will be used for long-term production cost modeling and the latest 2019 UPLAN model from the 2016 Regional Transmission Plan (RTP) will be used for the near-term production cost modeling. The 2026 UPLAN model will be modified to create a 2025 Scenario and the 2019 UPLAN model with be modified to create a 2020 Scenario as described in sections below.
   c. 2021 summer peak case from the 2016 RTP will be used for subsynchronous resonance (SSR) analysis.

2.3. SPP and ERCOT will use the same representation of the LP&L system as provided by LP&L.

The following load assumptions shall be used:

2.4. SPP will use the following load assumptions:
    a. 2021 summer peak and light load from 2017 ITPNT cases
2.5. ERCOT will use the following load assumptions:
    a. The load assumptions from the latest WFW 2021 summer peak case from the 2016 RTP will be used for reliability analysis. The North Weather Zone load will be scaled up to its forecasted 2021 peak for this analysis. The load forecast used is the higher of ERCOT's 90th percentile forecast for West, Far West, and North weather zones or the Transmission Service Provider (TSP) provided forecast for these zones.
    b. The latest 2026 UPLAN model from the 2016 Long-Term System Assessment (LTSA) Current Trends scenario will be used for long-term production cost modeling with loads scaled down per 2016 LTSA Scope to match 2016 LTSA forecast for 2025. The latest 2019 UPLAN model from the 2016 RTP will be used for the near-term production cost modeling with loads scaled up per 2016 RTP Scope to match 2016 RTP forecast for 2020. The load forecast and profile are based on a 2006 weather year pattern.
2.6. SPP and ERCOT will use the same representation of the LP&L load as provided by LP&L. For reliability analysis both the LP&L "Business As Usual (BAU)" and the LP&L "High Growth" load forecast will be analyzed. For production cost modeling the LP&L BAU load forecast will be used. The hourly load profile will be the same for SPP and ERCOT production cost analyses.

The following generation assumptions shall be used:

2.7. SPP will use the following generation assumptions:
    a. The reliability analyses will use generation assumptions per Integrated Transmission Planning Manual Section 3.3.1.2.
    b. The production cost analyses will use generation assumptions per ITP10 reference case (Future 3).
    c. Wind and solar profiles will be used in the production cost analysis.
2.8. ERCOT will use the following generation assumptions:
    a. The 2021 reliability analyses will include all existing generation plus planned generation meeting the conditions of Planning Guide Section 6.9. Known generation retirements will be turned off in the models.
    b. The 2025 production cost analyses will use generation assumptions from the Current Trends scenario based on the 2016 LTSA Scope. And, the 2020 production cost analysis will use generation assumptions per the 2016 RTP Scope.
    c. Wind and solar profiles will be used in the production cost analysis. The profiles will be based on a 2006 weather year pattern.
2.9. SPP and ERCOT will represent the LP&L generation, including generation retirements, as provided by LP&L. The production cost modeling assumptions for LP&L generation will also be identical for SPP and ERCOT.
2.10. ERCOT and SPP will use consistent natural gas price forecast
2.11. Wind and solar will be modeled as $0 marginal cost in the production cost analysis.
2.12. The Golden Spread Electric Cooperative Antelope/Elk switchable unit status will be consistent between ERCOT and SPP.
2.13. In the production cost analysis:
    a. SPP will perform the analysis with and without generation forced outages.

b. ERCOT will perform the analysis without generation forced outages.

For reliability analysis, the North and East DC tie import/ export assumptions will be consistent. ERCOT and SPP will review the production cost results with respect to North and East DC tie imports/ exports for reasonability and consistency.

3. Scope

The following are the analyses to be performed per Chairman Nelson's memo:

3.1. SPP reliability analysis

a. SPP will perform a reliability analysis to determine what transmission improvements will be needed or deferred as a consequence of the LP&L system moving to ERCOT. The analyses may include a net present value (NPV) analysis to determine the cost/ benefit of accelerating/ deferring a project. For consistency, SPP and ERCOT will use the same discount rates for NPV calculations.
b. The reliability analysis will be performed for 2021 summer peak and light load conditions.
c. As part of this analysis SPP will report the costs necessary to disconnect the LP&L system from SPP.

3.2. SPP and ERCOT avoided or new projects analysis

a. SPP will investigate projects in the area that were approved and have not yet gone into service to determine if those projects are no longer needed if the LP&L system moves to ERCOT. SPP will report the list of projects along with their estimated cost.
b. SPP will assess the need of any new transmission as a result of the LP&L system moving to ERCOT. SPP will report the list of potential projects along with their estimated cost.
c. ERCOT will take into account the results of the Lubbock Integration Study and the 2016 RTP and 2016 LTSA to determine if there are any avoided or new transmission improvement projects as a result of the LP&L system moving to ERCOT. ERCOT will report the list of projects along with their estimated cost.
d. The above analyses may include a net present value (NPV) analysis to determine the cost/ benefit of accelerating/ deferring a project. For consistency, SPP and ERCOT will use the same discount rates for NPV calculations.

3.3. SPP and ERCOT production cost analysis

a. SPP will perform a production cost analysis with and without the LP&L system (taking into account the results from 3.1). SPP will report the regional production cost difference and the adjusted production cost differences.
b. ERCOT will perform a production cost analysis without and with the LP&L system (taking into account the results from the Lubbock Integration Study and 3.2). ERCOT will report the production cost difference.
c. The production cost analysis will be performed for years 2020 and 2025 with loads and generation modeled as described in previous sections of this document. Transmission projects expected to be in-service by 2020 will be added to the 2016 RTP 2019 UPLAN case to reflect expected 2020 transmission topology. However, due to the magnitude of

uncertainty, the 2025 transmission topology will remain the same as the topology in the 2016 LTSA Current Trends 2026 UPLAN case.

d. SPP and ERCOT will report total production cost difference as a result of the LP&L system moving to ERCOT.
    i. SPP and ERCOT will report total adjusted production cost impact for Texas

3.4. Operational cost and reliability impact assessment
    a. SPP will provide a qualitative description of the reliability impact of the LP&L system moving to ERCOT.
    b. ERCOT will provide a qualitative description of the reliability impact of the LP&L system moving to ERCOT. The description may include system strength benefits and the benefit of load in the ERCOT Panhandle.

3.5. Ancillary services impact analysis
    a. ERCOT and SPP will provide a qualitative description of the impact on ancillary services.

3.6. Congestion rights impact analysis
    a. ERCOT and SPP will provide a qualitative description of the impact on congestion rights.

3.7. SSR impact analysis
    a. ERCOT will perform a topology check for the ERCOT system to evaluate the SSR impact on existing and planned ERCOT generation units.
    b. Based on the results in (a) above, ERCOT may perform a frequency scan for existing and planned ERCOT generation units.
    c. Based on the results in (b) above, ERCOT may perform a detailed SSR analysis for existing and planned ERCOT generation units. This analysis may need to be contracted out.
    d. Based on the results of (a), (b), and (c) above ERCOT will assess the cost impact from an SSR perspective, including potential cost savings, as a result of the LP&L system moving to ERCOT.

3.8. LP&L generators to synchronous condenser analysis
    a. ERCOT will perform a system strength analysis (weighted short circuit ratio determination) to determine the impact to the Panhandle export limit of converting some or all of LP&L's retiring generators to synchronous condensers.
    b. ERCOT will perform a production cost analysis using the 2020 UPLAN model to determine the annual production cost benefit of converting some or all of LP&L's retiring generators to synchronous condensers based on (a) above.
    c. ERCOT will compare the production cost savings to the LP&L provided cost to convert the retiring LP&L generators to synchronous condensers to determine if the cost would be justified.

3.9. The following analysis recommended in Chairman Nelson's memo cannot be performed by SPP and ERCOT:
    a. ERCOT is not able to provide an evaluation of the cost and reliability impacts on all customer classes in ERCOT. However, ERCOT can provide average LMP impacts for all substations in the ERCOT Region.
    b. An evaluation of LP&L's ability to ensure that comingling of the SPP and ERCOT systems will not occur.

4. Deliverable

SPP and ERCOT will file a joint report to the PUCT by Q2 2017.


SPP
Southwest
Power Pool
HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.

SPP Southwest Power Pool

Scope Standardization – Siting Plan Process

February 15,2017

Overview

- ESWG Action Item – SPP ITP Siting Plan Process Whitepaper
- SPP staff draft - expediently in progress
  - Overall theme – Leverage existing ITP manual philosophies and 2017 ITP10 siting plan process with improvements from lessons learned
- Next steps
  - Post draft for stakeholder feedback
  - Incorporate stakeholder feedback
  - Post draft for final review and approval
  - Approve whitepaper and recommendations for scope standardization
  - Draft language and approve language for standardized scope
  - Implement recommended process

APPENDIX

Scope Standardization – Siting Plan Process

Resource Siting Plan - Conventional

- Investigating process questions and details for members to add publicly available Integrated Resource Planning resources with siting into Model on Demand
  - Applicability to planning models
  - Requirement for Resource Addition Requests
- Leverage and expand generation siting repository
  - Collection of sites from GI Queue, previous studies, staff and member alternatives
  - Includes retirement dates of existing resources for replacement
  - Includes transmission interconnection capability screening
  - Include other suitability attributes by site
  - Provided to members for new site updates and ranking at beginning of milestone
  - Rank sites by zone
  - Tracking of study to study resource plans
- Assignment by Zone

Resource Siting Plan - Wind

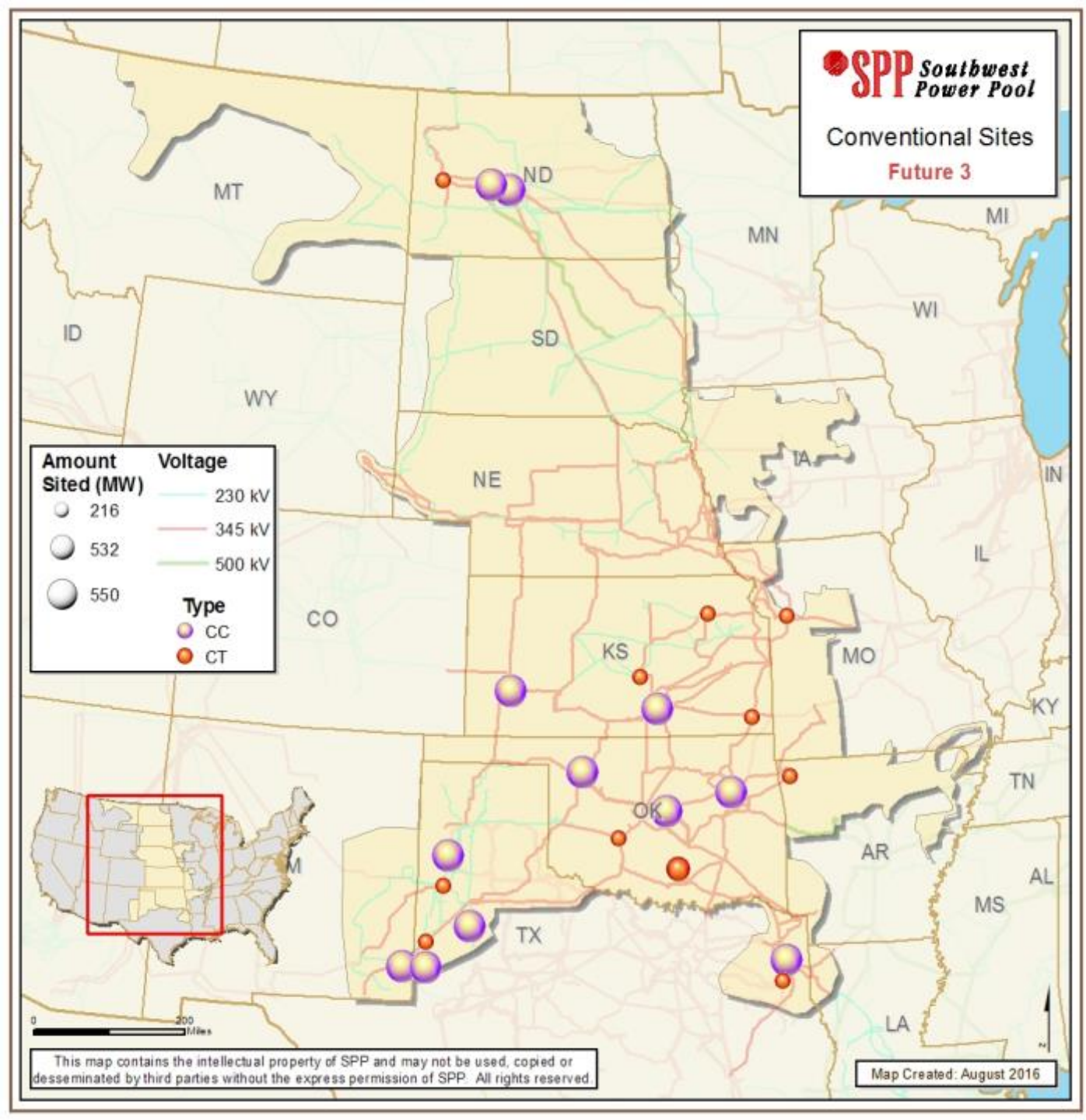
- Leverage Generation Interconnection queue until such time the resources plan additions exceed ranked statuses
- Ranked generation interconnection queue statuses
  - IA on-schedule
  - IA on-suspension
  - IA commercial operation not fully on-line
  - IA Pending
  - Facility Study
- Additional rankings by capacity factor by interconnection costs
- Assignment by Zone by State by Region

Resource Siting Plan - Solar

- Leverage Generation Interconnection queue then supplement using NREL comprehensive data set
- Additional rankings by capacity factor by interconnection costs or interconnection capability screening
- Assignment by Zone by State by Region

2017 ITP10 Siting Plan

Conventional Maps


SPP Southwest Power Pool
Conventional Sites
Future 3
Amount Sited (MW)
216
532
550
Voltage
230 kV
345 kV
500 kV
Type
CC
CT
MT
ND
MN
MI
ID
SD
WI
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
AL
MS
TX
LA
0
200
Miles
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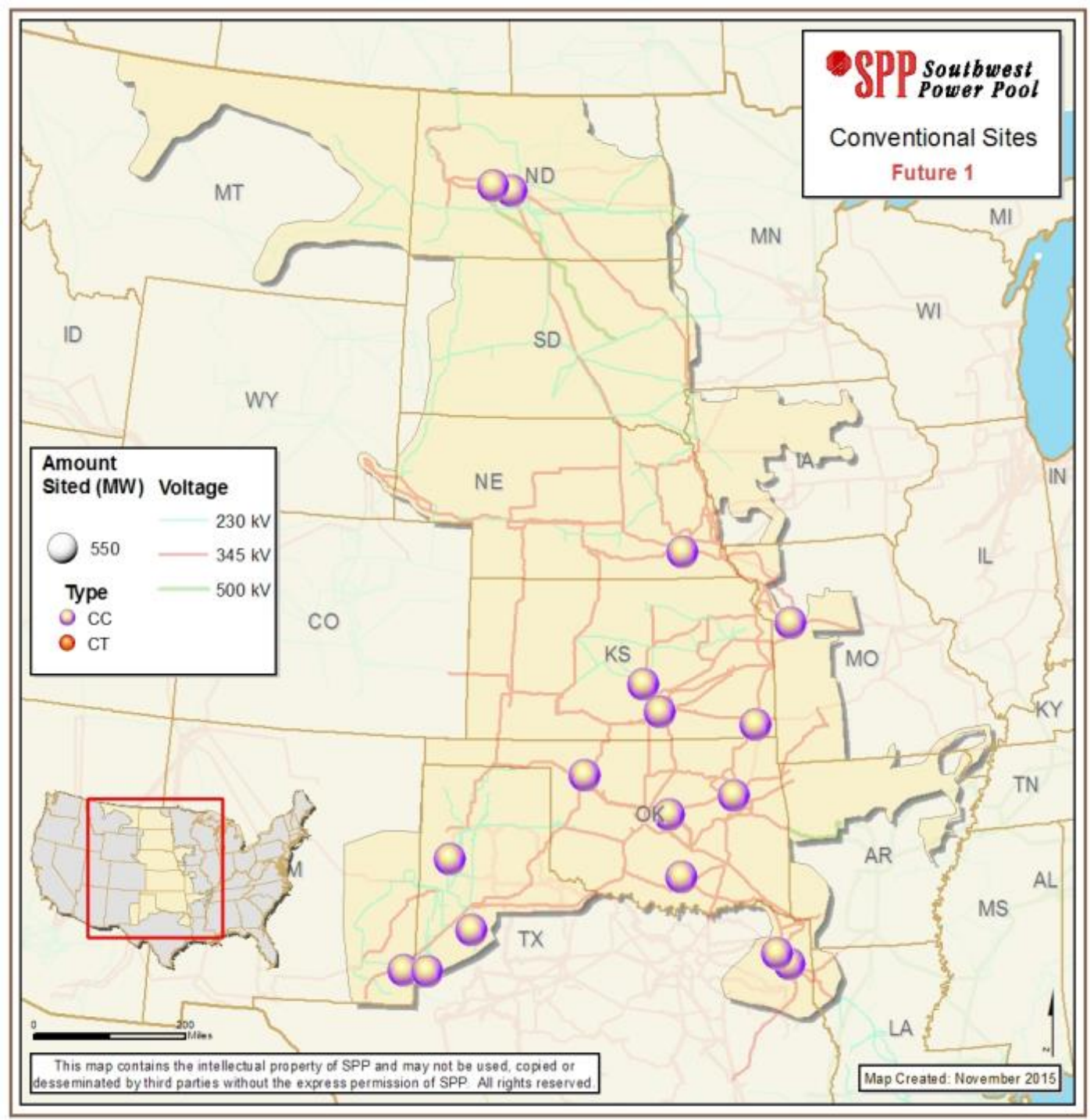
Map Created: August 2016


SPP Southwest Power Pool
Conventional Sites
Future 1
Amount Sited (MW)
550
Type
CC
CT
Voltage
230 kV
345 kV
500 kV
ND
MT
MN
MI
WI
ID
SD
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
AL
MS
TX
LA
0
200
Miles
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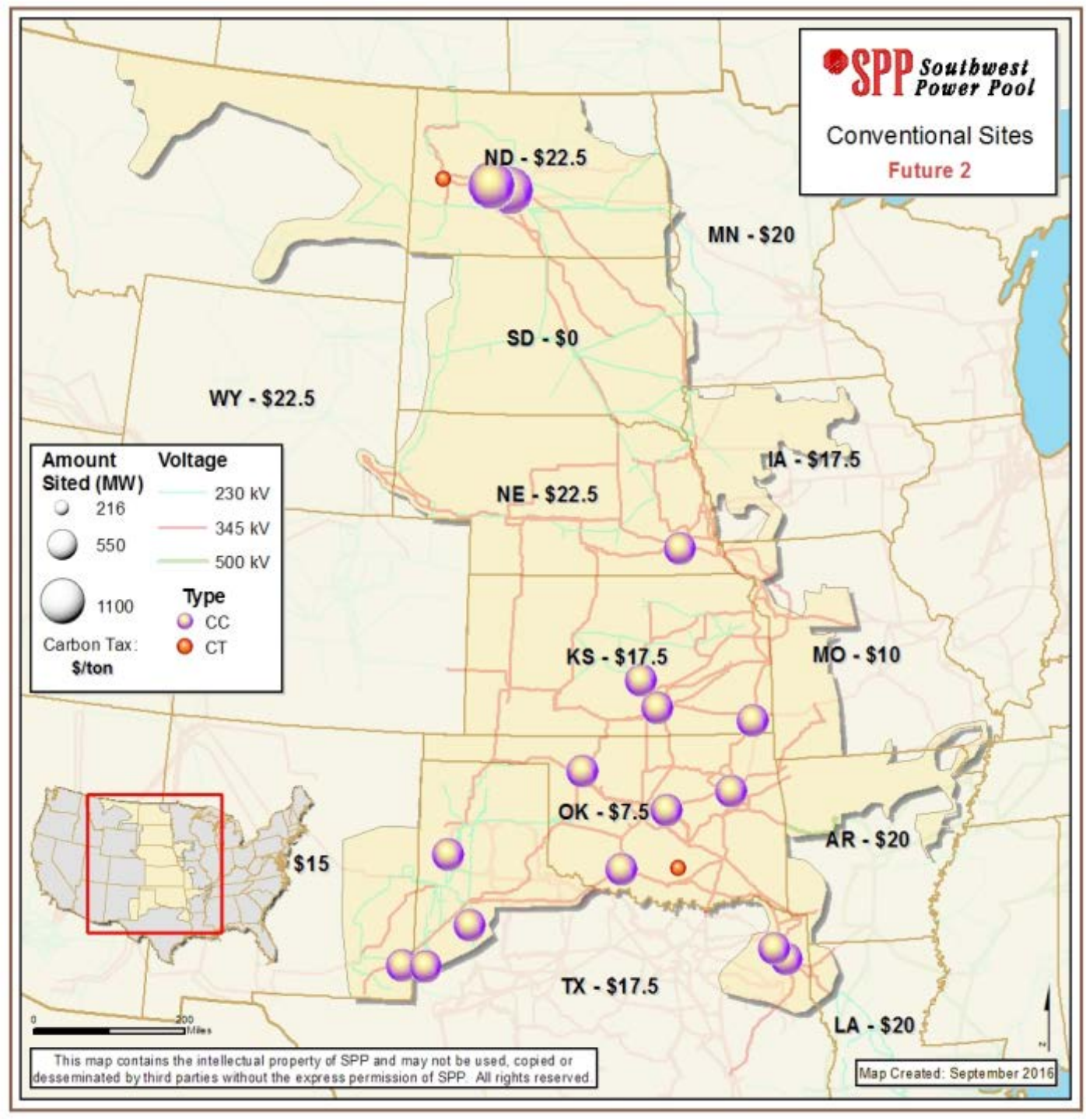
Map Created: November 2015


SPP Southwest Power Pool
Conventional Sites
Future 2
ND - $22.5
MN - $20
SD - $0
WY - $22.5
IA - $17.5
NE - $22.5
KS - $17.5
MO - $10
OK - $7.5
AR - $20
$15
TX - $17.5
LA - $20
Amount Sited (MW)
216
550
1100
Carbon Tax: $/ton
Voltage
230 kV
345 kV
500 kV
Type
CC
CT
0
200
Miles
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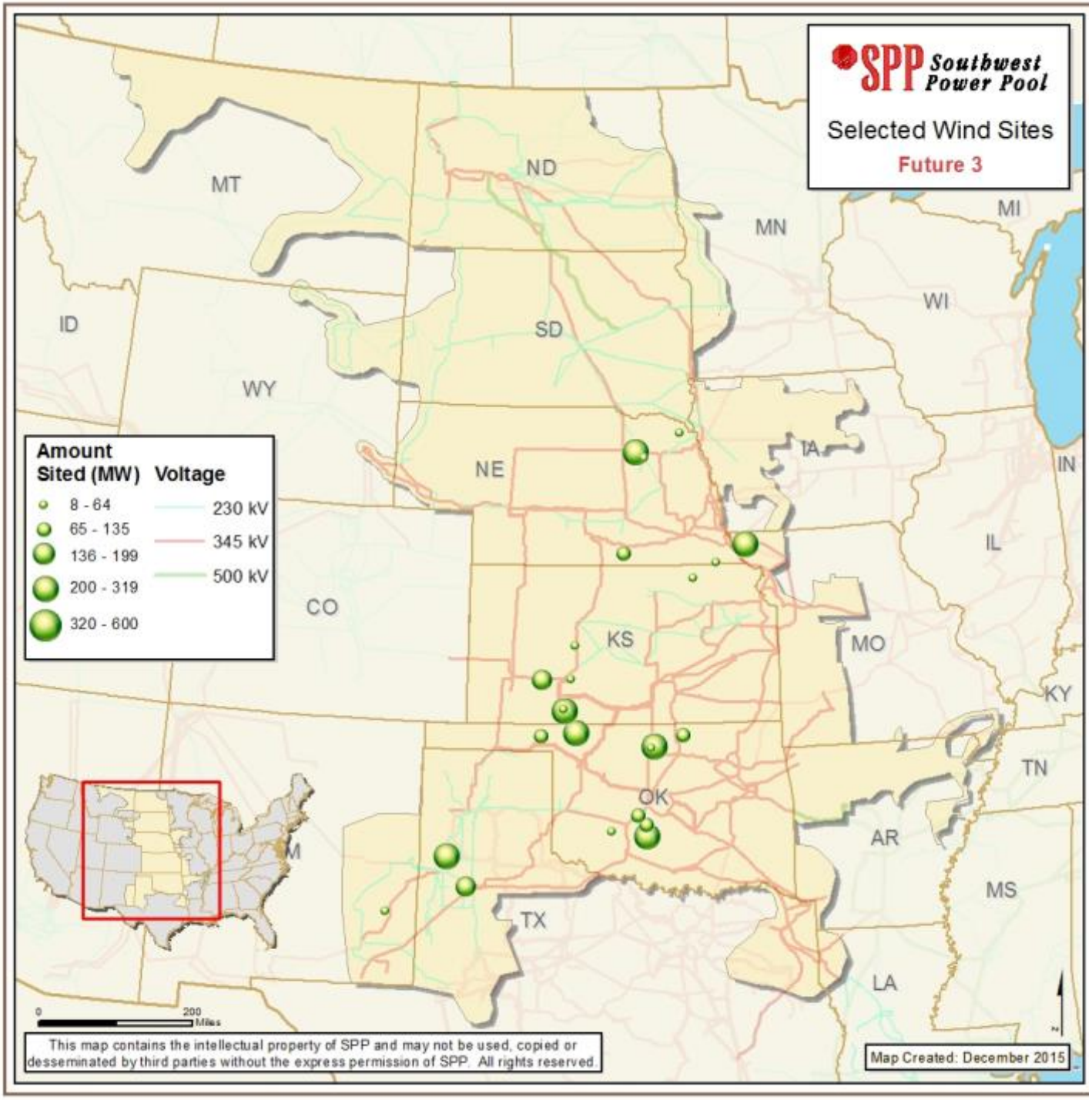
Map Created: September 2016

C

2017 ITP10 Siting Plan

Wind Maps


SPP Southwest Power Pool
Selected Wind Sites
Future 3
Amount Sited (MW)
8 - 64
65 - 135
136 - 199
200 - 319
320 - 600
Voltage
230 kV
345 kV
500 kV
MT
ND
MN
MI
ID
SD
WI
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
MS
TX
LA
0
200
Miles
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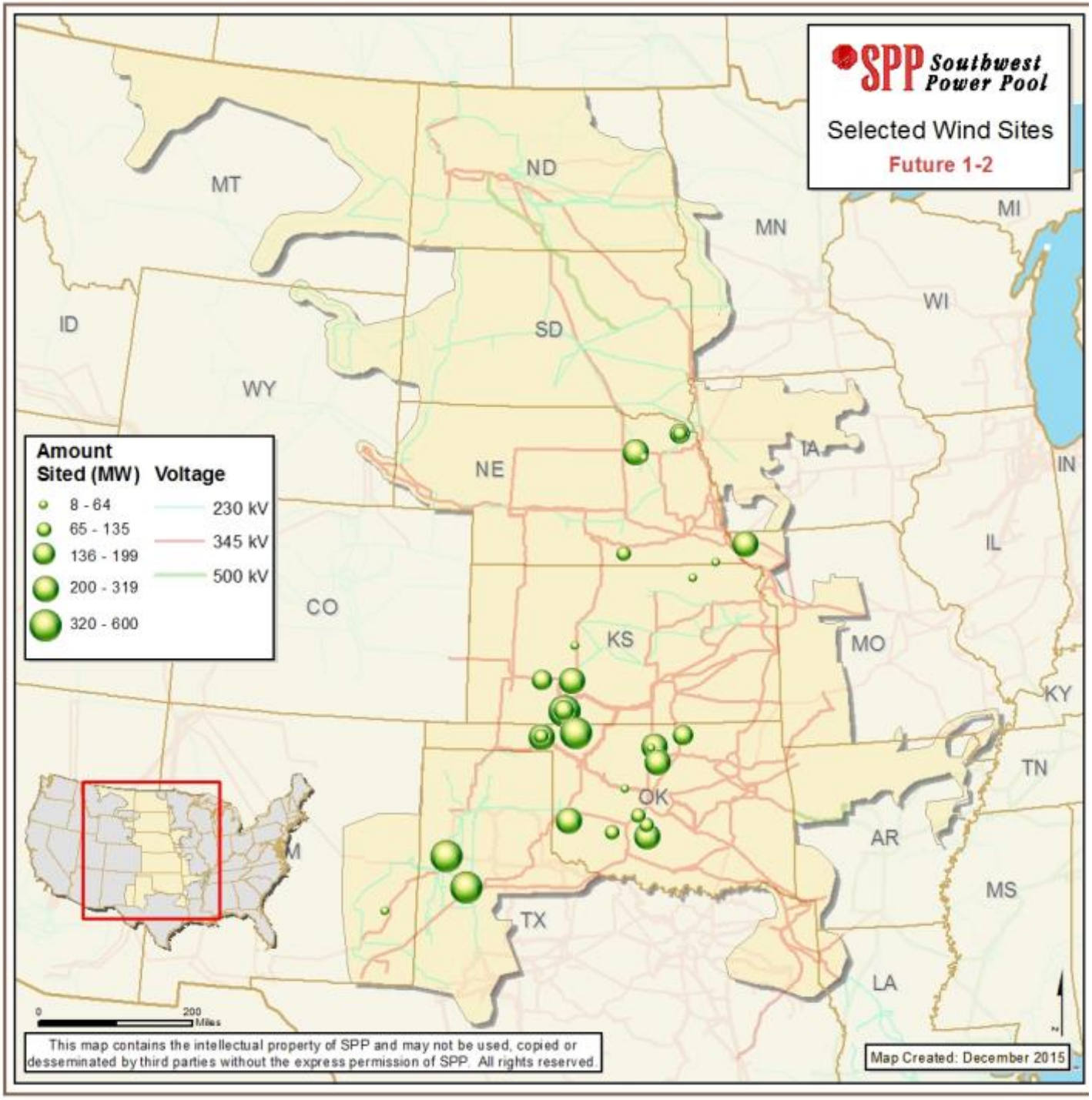
SPP Southwest Power Pool
Selected Wind Sites
Future 1-2
Amount Sited (MW)
8 - 64
65 - 135
136 - 199
200 - 319
320 - 600
Voltage
230 kV
345 kV
500 kV
MT
ND
MN
MI
ID
SD
WI
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
MS
TX
LA
0
200
Miles
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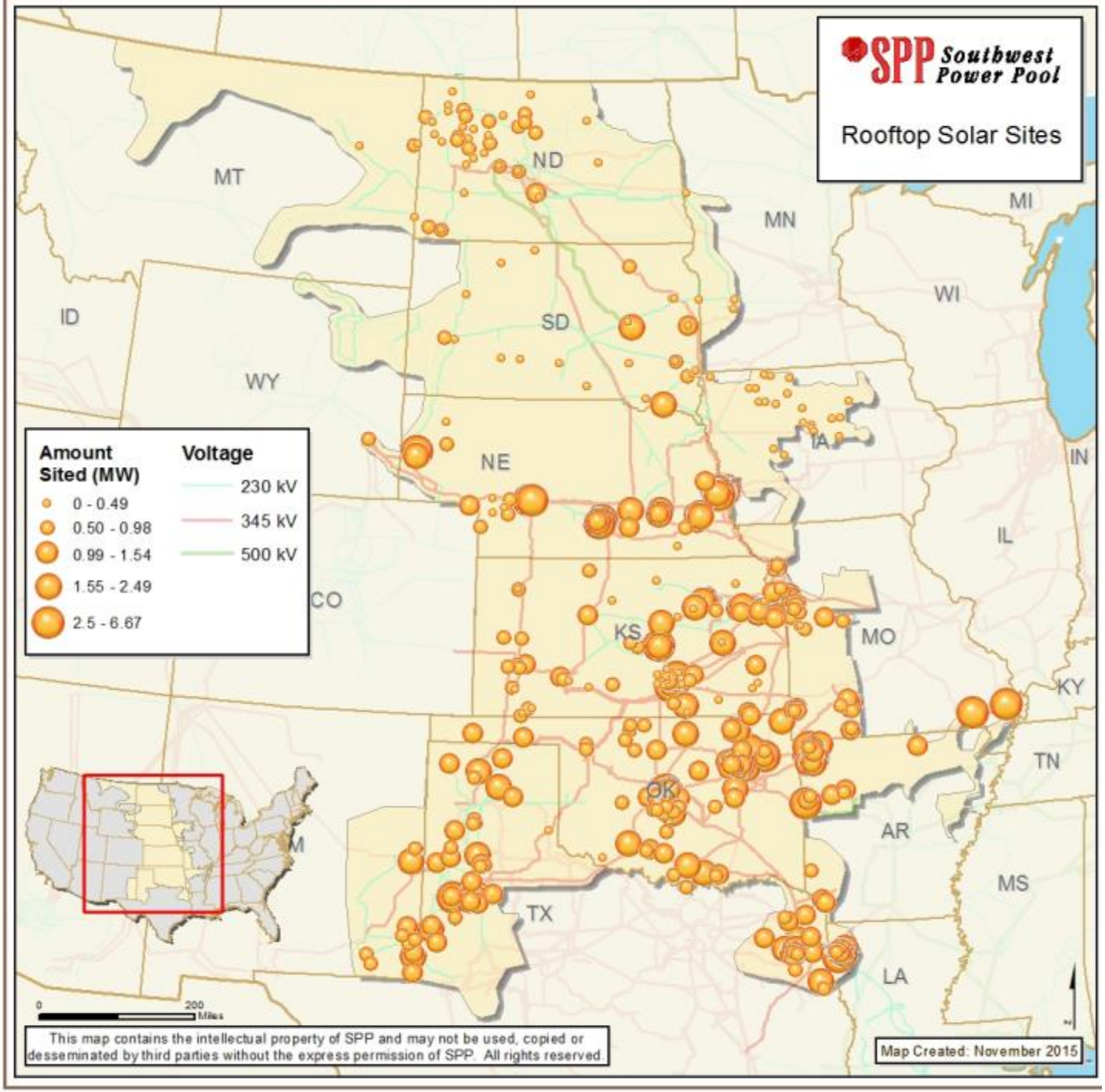
2017 ITP10 Siting Plan

Solar Maps


SPP Southwest Power Pool
Rooftop Solar Sites
Amount Sited (MW)
0 - 0.49
0.50 - 0.98
0.99 - 1.54
1.55 - 2.49
2.5 - 6.67
Voltage
230 kV
345 kV
500 kV
MT
ND
MN
MI
WI
ID
SD
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
MS
TX
LA
0
200
Miles
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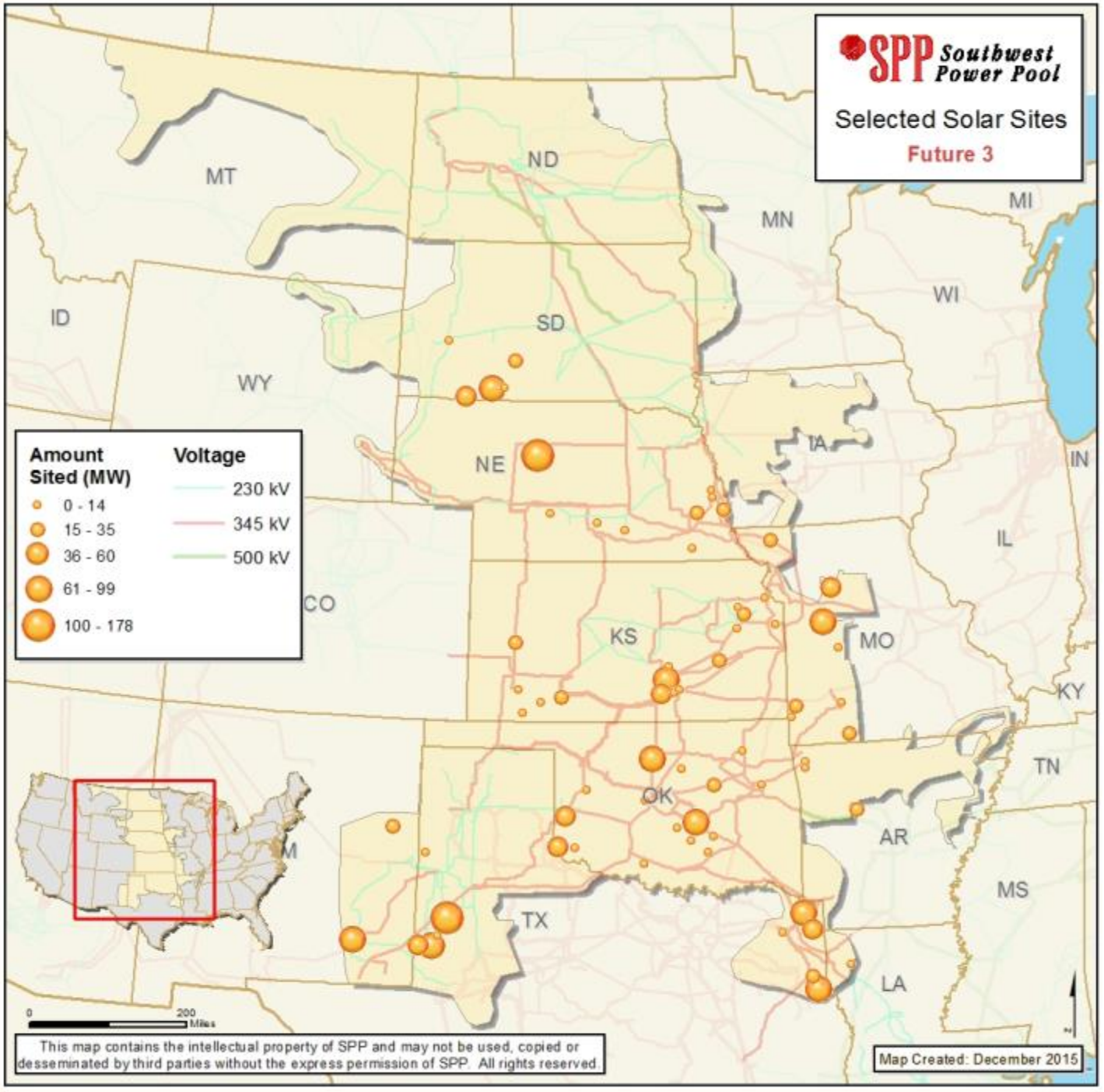
SPP Southwest Power Pool
Selected Solar Sites
Future 3
Amount Sited (MW)
0 - 14
15 - 35
36 - 60
61 - 99
100 - 178
Voltage
230 kV
345 kV
500 kV
MT
ND
MN
MI
ID
SD
WI
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
MS
TX
LA
0
200
Miles
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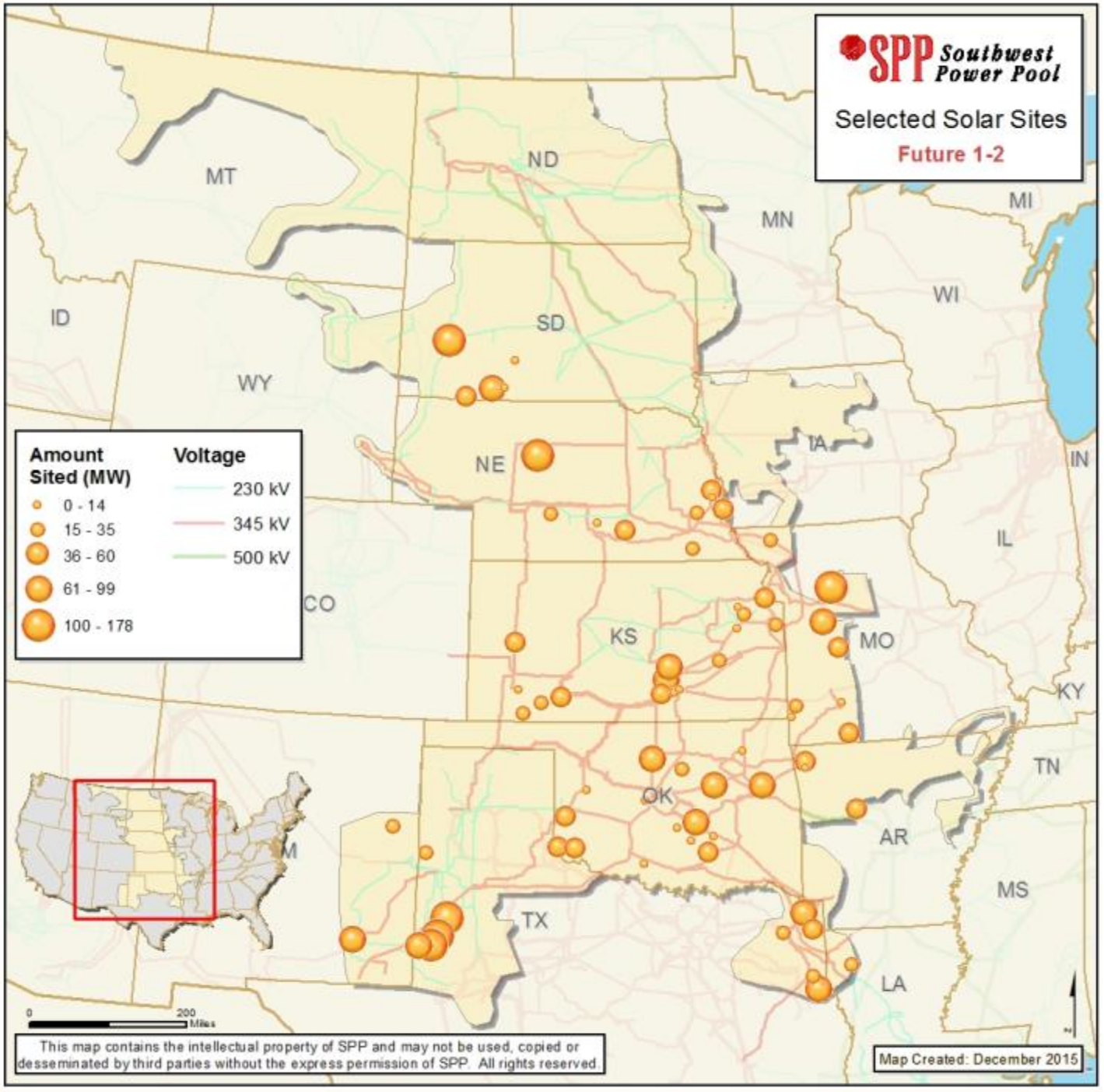
Map Created: December 2015


SPP Southwest Power Pool
Selected Solar Sites
Future 1-2
Amount Sited (MW)
0 - 14
15 - 35
36 - 60
61 - 99
100 - 178
Voltage
230 kV
345 kV
500 kV
MT
ND
MN
MI
ID
SD
WI
WY
NE
IA
IN
IL
CO
KS
MO
KY
TN
OK
AR
MS
TX
LA
0
200
Miles
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Map Created: December 2015

SITING RESEARCH

- SPP Process to date
- Other RTO processes
- Utility Processes
- Regulatory Body Processes

SPP SITING PROCESS

- SPP Manual (Screening Level exercise)
  - Do not use transmission as initial siting factor
  - Site proxy generation by zone
  - Avoid greenfield siting for NG fired capacity
  - Limit capacity to 2,400 MW maximum per location

SPP SITING PROCESS

- 2013 ITP20 siting process (Suitability Analysis)
  - Data Acquisition
  - Data Processing - Included Uncommitted GI Locations
  - Weighted Overlay Analysis
  - Resource Siting

OTHER RTO PROCESSES

- MISO Process
  - Consideration of GI Queue resources (Planned, Future, and Canceled)
  - Siting rules per future
  - Site Priority
    - GI Queue resources
    - Brownfield Sites
    - Retired/mothballed sites that have not been re-used
    - Greenfield sites using GI Queue
    - Greenfield sites using Greenfield siting methodology
  - Specific greenfield siting rules per resource type

https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=184861
MTEP14 Appendix E2 – EGEAS

OTHER RTO PROCESSES

- PJM Process
  - Model Queued Generation by queue priority and status as needed
- ERCOT Process
  - Resource Type Suitability by County
  - Use 345kV buses
  - Use highest LMP for competing sites
  - Siting Priority similar to MISO

https://www.pjm.com/documents/reports/rtep-documents.aspx
White Paper (PDF)7.2.2014
http://www.ercot.com/content/committees/other/lts/keydocs/2013/DOE_LONG_TERM_STUDY_-_Draft_V_1_0.pdf
http://www.ercot.com/content/meetings/rpg/keydocs/2014/0722/LTSA_7-22-2014_Scenario_Results.ppt

SITING OBJECTIVES DISCUSSION

- Site Resources from SPP's Resource Plan Process
  - Up to 20% of the conventional resources in the study
  - Includes Conventional and Renewable Resources
- What are some siting dos and don'ts?
  - What are the gaps with existing suitability analysis?

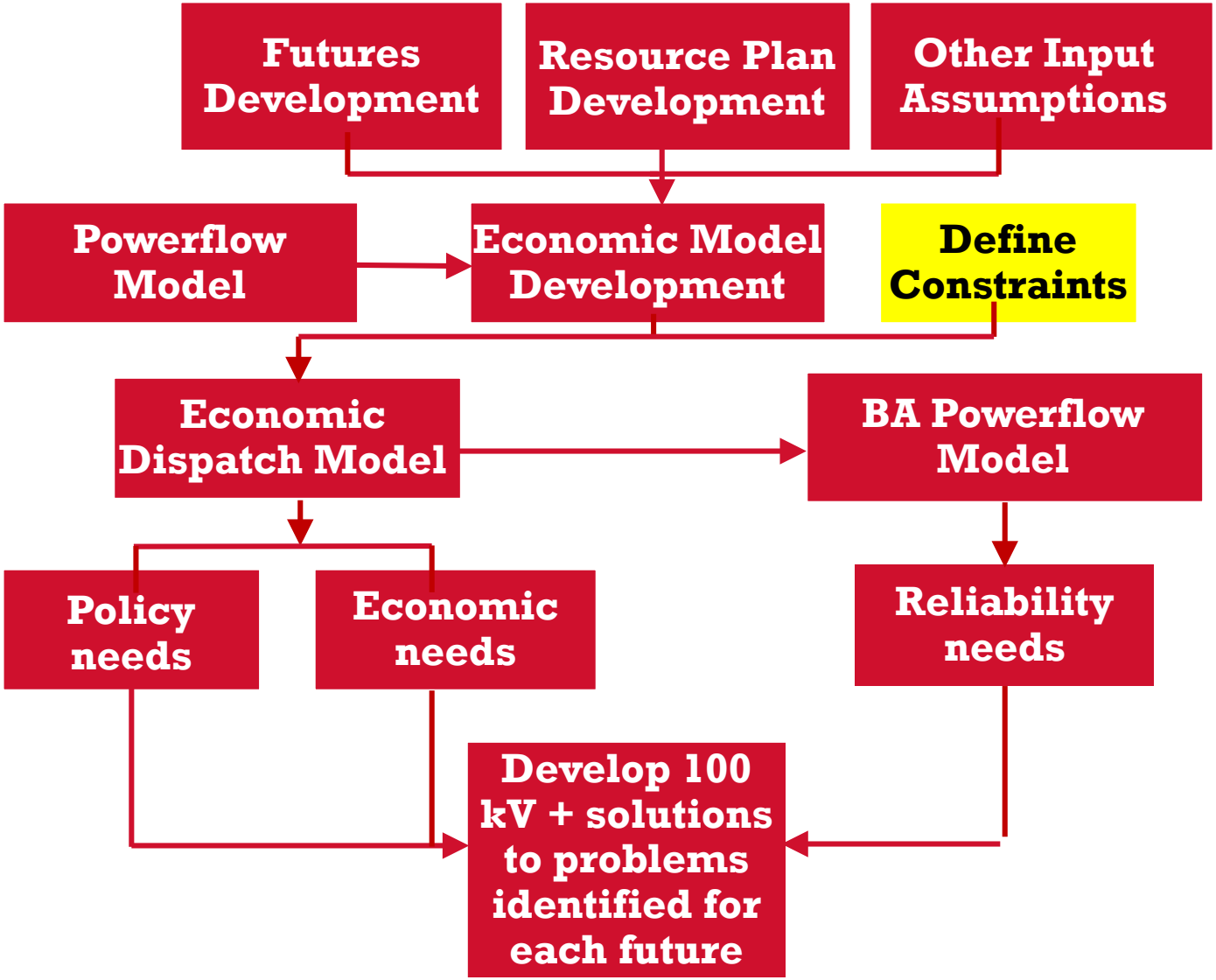
CONCEPTS FOR CONSIDERATION

- Use previous study resource sites
- Leverage GI queue and study results to a reasonable extent
- Expand suitability analysis
- Point of interconnect (POI) Available Transfer Capability to minimize Generator Outlet Facilities
- Load pocket analysis to recognize needs to locally site capacity versus energy based resources

NEXT STEPS

- Draft Straw man by April 24th, 2015
- Review straw man proposal with ESWG May 20th, 2015
- 2017 ITP10 Siting - September through January 2015

ITP10 Process



PAT Tool Overview

- PROMOD Analysis Tool
- "A tool for analyzing transmission constraints…"
- Compatible with files from PROMOD
- Utilized as part of Constraint Assessment process
  - Create events for peak, off-peak, and 8760
  - Combine events into one event file
  - Validate event file format

Defining Contingencies

- Simulated two PROMOD 8760 runs
  - Copper Plate Event File (blank)
  - Event file starting with Permanent Flowgate events
- Determine reliability hours using software
- Use PROMOD dispatch in PAT to create contingency list
  - Create outages for elements exceeding 50% loading for 100kV+ in Peak and Off-Peak hours
  - Create outages for elements exceeding 25% loading for 200kV+ in Peak and Off-Peak hours (SPP Only)

Defining Contingencies

- Use PAT to create Peak and Off-Peak contingency lists based on PAT dispatch in respective hour
  - Create outages for elements exceeding 50% loading for 100kV+
  - Create outages for elements exceeding 25% loading for 200kV+ (SPP Only)
- Remove invalid contingencies
  - 2016 Near Term invalid contingency list
  - 2015 ITP10 invalid contingency list
  - Effort to simulate breaker-breaker
  - Effort to remove radials
- Include contingencies identified in SPP's Permanent Flowgate workbook in all contingency lists
- Include contingencies identified in SPP's Temporary Flowgate list in all contingency lists

Defining Events

- Utilize respective validated contingency lists for 8760, Peak, and Off-Peak analyses
- Peak and Off-Peak Constraints automatically included
- Monitored element selection (8760 Only):
  - Include monitored elements 100kV+
    - SPP: 800 hours
    - Non-SPP: 1200 hours
    - New monitored elements below set thresholds included
  - PROMOD congestion score
  - PROMOD emergency generation
  - Constraints found breaching generally not included in event file

Discussion Topics

- PAT Tool Overview
- Contingency Screening
- Automatic Constraints from Reliability Hours
- TPL Planning Event Contingencies Temporary flowgates
- Exclusion of Breaching Constraints
- Combining Economic Needs Assessment and Constraint Assessment together (delay approval of economic model)
- Other Considerations

PAT Tool Overview

- Help from EPL
- Explanation for TWG and ESWG exactly what PAT is/does

Contingency Screening

- Use PROMOD dispatch in PAT to create 8760 contingency list
  - Create outages for elements exceeding 50% (+ 10% LODF) loading for 100kV+ in Peak and Off-Peak hours
  - Create outages for elements exceeding 25% loading for 200kV+ in Peak and Off-Peak hours (SPP Only)
    - 68/668 Contingencies
    - 98/1575 Mon/Con pairs
    - 3 Mon/Con pairs with congestion score greater than 50k (2 Needs)

Contingency Screening Recommendation

- Staff recommends no changes:
  - Create outages for elements exceeding 50% loading for 100kV+ in Peak and Off-Peak hours
  - Create outages for elements exceeding 25% loading for 200kV+ in Peak and Off-Peak hours (SPP Only)
  - No copper plate analysis of constraints
    - 62/668 contingencies
    - 182/1575 mon/con pairs
    - 15 mon/con pairs with congestion scope > 50k (6 economic needs)

Automatic Constraints from Reliability Hours

- Constraints observed in either reliability hours automatically included in constraint assessment
- Staff Recommendation:
  - Constraints observed in the reliability hours generally included in the constraint list, but may be excluded based upon staff's engineering judgement and review with stakeholders

TPL Planning Events

- Current ITP Manual language

For the purposes of the ITP10 study, the transmission constraint list will be limited to the following types of issues so that there is a focus on disturbances on the HV and EHV systems:

- System Intact and N-1 situations
- Existing common right-of way and tower contingencies for 100+ kV facilities[7]
- Thermal loading and voltage stability interfaces
- Contingencies of 100 kV or higher voltage transmission lines only
- Contingencies of transformers with a 100 kV or higher voltage winding only
- Monitored facilities of 100 kV and above voltages only

Due to the limit on the number of constraints that can be monitored by the economic modeling tool, not every flow will always be mitigated for every hour. Overloads can occur. The constraint selection process is designed so that the constraints that would be most likely to occur during the simulated hours are mitigated.

---

[6] NERC Standard TPL-001-4 Table 1 includes outages of any two circuits of a multiple circuit tower as a Planning event P7, and the loss of all transmission lines on a common right-of-way as an Steady State & Stability Performance Extreme Event SS2.b.

[7] NERC Standard TPL-001-4 Table 1 includes outages of any two circuits on a common structure as a Planning event P7, and the loss of all transmission lines on a common Right-of-Way as a Steady State Performance Extreme Event SS2.b.

TPL Planning Events

Event Category	Voltage Level	Description
P0	EHV, HV	P0: No contingency
P1	EHV, HV	P1.1: Single (Generator)
	EHV, HV	P1.2: Single (Transmission Circuit)
	EHV, HV	P1.3: Single (Transformer)
	EHV, HV	P1.4: Single (Shunt)
	EHV, HV	P1.5: Single (Single Pole of a DC line)
P2	EHV, HV	P2.1: Single (No fault line section)
	EHV	P2.2: Single (Bus section)
	EHV	P2.3: Single (Internal Breaker Fault [non-Bus-tie breaker])
P7		ADD P7 Event info here

TPL Planning Event Contingencies

- Inconsistency between members on validity of certain Planning Events
  - Staff Action Item: Work with stakeholders to develop documented method on identification of Planning Events
  - Vetted through TWG for approval

- Staff Recommendation:
  - Staff recommends including P1 and P2 events as contingencies for potential constraints, with consideration of P7 events if included in the list of permanent flowgates

Temporary Flowgates

- Current ITP10 process does not consider 69 kV limitations when performing SCUC/SCED process
  - Results in overloads for < 100kV facilities
- RC mostly considers Bulk Electric System
  - TOs request help for 69 kV system
  - 69 kV facilities are incorporated into the market by the use of temporary flowgates
  - Action Item: How many 69 kV temp flowgates are there? (Chris) 25 on 2/1/2017
- Staff Recommendation:
  - Allow staff to use engineering judgement with feedback from SPP Operations to incorporate temporary flowgates on the 69 kV system into the constraint list
    - Develop proxy constraints for 69 kV issues
    - LODF on 100kV + system for impact on 69 kV
    - GSF for 69 kV facilities
    - Goal is to develop appropriate sized solution (69 kV for reliability or 100 kV+ for economic) for cause of violation

Feedback loop process

- Combining Economic Needs Assessment and Constraint Assessment together (delay approval of economic model) (Chris idea, not sure how to present)
- Base model ACCC check, FCITC check, lowering monitoring %
- Something about a feedback loop with multiple DC/AC conversions and ACCCs
  - Adding constraints from AC overloads
  - Can we do something with voltage violations?

Other Considerations

- Reclassification of Needs
  - Done in 2017 ITP10
- Number of constraint files
  - Up to 7 economic models
- How to handle constraints that do not appear in multiple Years (i.e. Year 2 and Year 5, but not Year 10)
  - Bigger event file = longer PROMOD runs
  - Since May 2013: ~13k PROMOD runs , 6-8 hours per run
  - Staging impact for economic projects also a consideration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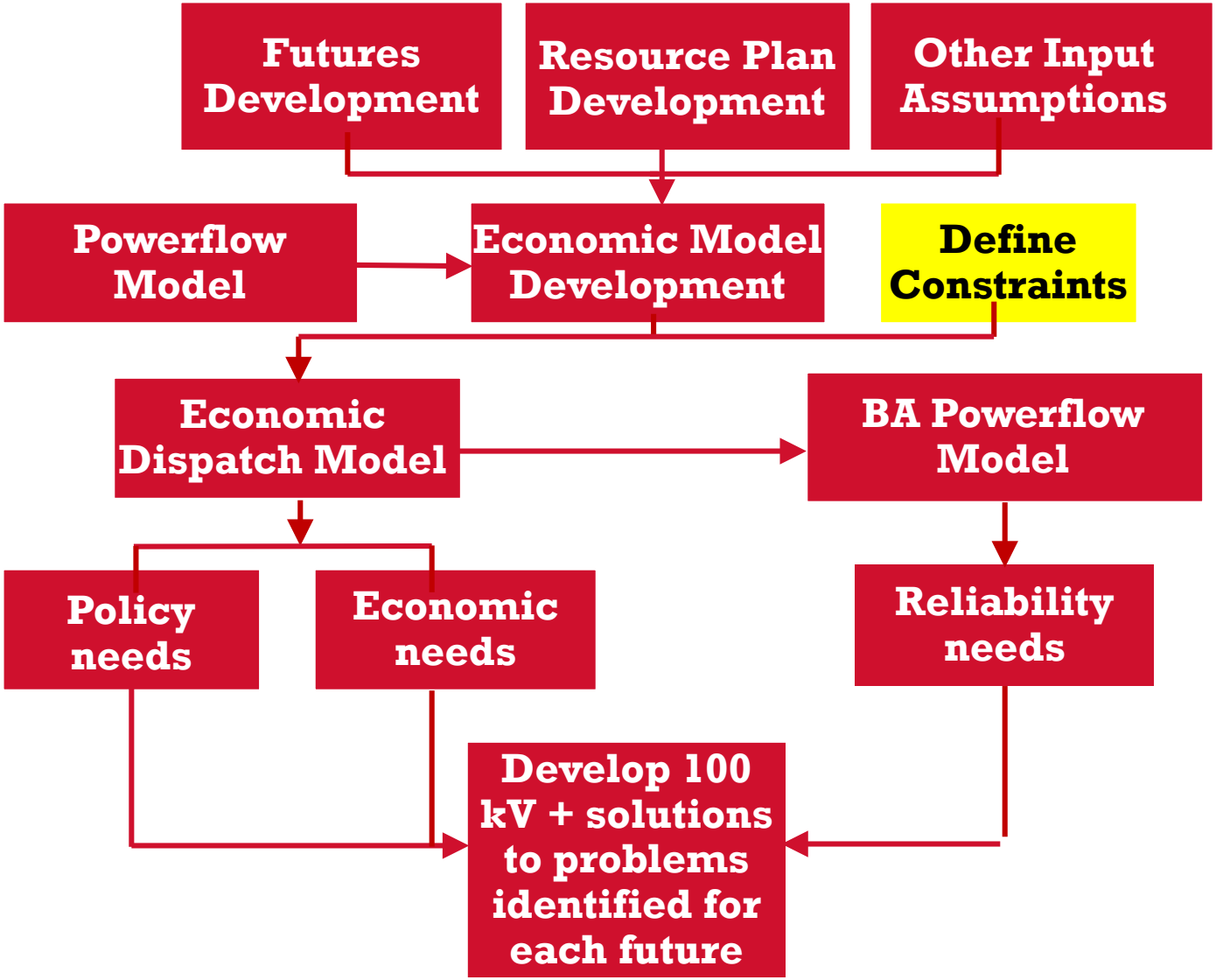
Scope Standardization – Constraint Assessment

February 15,2017

Overview

- Current Process
- PAT Overview
- Current Process (2017 ITP10)
- Recommendations for standardization

ITP10 Process



PAT Tool Overview

- PROMOD Analysis Tool
- "A tool for analyzing transmission constraints…"
- Compatible with files from PROMOD
- Utilized as part of Constraint Assessment process
  - Create events for peak, off-peak, and 8760
  - Combine events into one event file
  - Validate event file format

Defining Contingencies

- Simulated two PROMOD 8760 runs
  - Copper Plate Event File
  - Event file containing SPP's Permanent Flowgate events
- Determine Peak and Off-Peak hours
  - SPP Coincident Peak Hour (Peak): August 6th at 5 pm
  - Peak Wind Penetration Hour (Off-Peak): January 4th at 5 am
- Use PROMOD dispatch in PAT to create 8760 contingency list
  - Create outages for elements exceeding 50% loading for 100kV+ in Peak and Off-Peak hours
  - Create outages for elements exceeding 25% loading for 200kV+ in Peak and Off-Peak hours (SPP Only)

Defining Contingencies

- Use PAT to create Peak and Off-Peak contingency lists based on PAT dispatch in respective hour
  - Create outages for elements exceeding 50% loading for 100kV+
  - Create outages for elements exceeding 25% loading for 200kV+ (SPP Only)
- Remove invalid contingencies and events
- Include contingencies identified in SPP's Permanent Flowgate workbook in all contingency lists
- Include contingencies identified in SPP's Temporary Flowgate list in all contingency lists

Defining Events

- Utilize respective validated contingency lists for 8760, Peak, and Off-Peak analyses
- Peak and Off-Peak Constraints automatically included
- Monitored element selection (8760 Only):
  - Include monitored elements 100kV+
    - SPP: 800 hours
    - Non-SPP: 1200 hours
    - New monitored elements below set thresholds included
  - PROMOD congestion score
  - PROMOD emergency generation
  - Constraints found breaching generally not included in event file

Discussion Topics

- Contingency Screening
- Automatic Constraints from Reliability Hours
- TPL Planning Events
- 69 kV Constraints
- Combining Economic Needs Assessment and Constraint Assessment together (delay approval of economic model)
- Reclassification of Needs
- Other Considerations

Contingency Screening

- Copper Plate Event File
  - 62/668 contingencies
  - 182/1575 mon/con pairs
  - 15 mon/con pairs with congestion score > 50k (6 economic needs)
- Use PROMOD dispatch in PAT to create 8760 contingency list
  - Create outages for elements exceeding 50% loading for 100kV+ in Peak and Off-Peak hours
  - Create outages for elements exceeding 25% loading for 200kV+ in Peak and Off-Peak hours (SPP Only)
    - 68/668 Contingencies
    - 98/1575 Mon/Con pairs
    - 3 Mon/Con pairs with congestion score greater than 50k (2 Needs)

Contingency Screening Recommendation

- Staff recommends no changes:
  - Create outages for elements exceeding 50% loading for 100kV+ in Peak and Off-Peak hours
  - Create outages for elements exceeding 25% loading for 200kV+ in Peak and Off-Peak hours (SPP Only)
  - Continue copper plate analysis

Automatic Constraints from Reliability Hours

- Constraints observed in either reliability hours automatically included in constraint assessment
- Staff Recommendation:
  - Constraints observed in the reliability hours generally included in the constraint list, but may be excluded based upon staff's engineering judgement and review with stakeholders

TPL Planning Events

- Current ITP Manual language

For the purposes of the ITP10 study, the transmission constraint list will be limited to the following types of issues so that there is a focus on disturbances on the HV and EHV systems:

- System Intact and N-1 situations
- Existing common right-of way and tower contingencies for 100+ kV facilities[7]
- Thermal loading and voltage stability interfaces
- Contingencies of 100 kV or higher voltage transmission lines only
- Contingencies of transformers with a 100 kV or higher voltage winding only
- Monitored facilities of 100 kV and above voltages only

Due to the limit on the number of constraints that can be monitored by the economic modeling tool, not every flow will always be mitigated for every hour. Overloads can occur. The constraint selection process is designed so that the constraints that would be most likely to occur during the simulated hours are mitigated.

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[6] NERC Standard TPL-001-4 Table 1 includes outages of any two circuits of a multiple circuit tower as a Planning event P7, and the loss of all transmission lines on a common right-of-way as an Steady State & Stability Performance Extreme Event SS2.b.

[7] NERC Standard TPL-001-4 Table 1 includes outages of any two circuits on a common structure as a Planning event P7, and the loss of all transmission lines on a common Right-of-Way as a Steady State Performance Extreme Event SS2.b.

TPL Planning Events

Event Category	Voltage Level	Description
P0	EHV, HV	P0: No contingency
P1	EHV, HV	P1.1: Single (Generator)
	EHV, HV	P1.2: Single (Transmission Circuit)
	EHV, HV	P1.3: Single (Transformer)
	EHV, HV	P1.4: Single (Shunt)
	EHV, HV	P1.5: Single (Single Pole of a DC line)
P2	EHV, HV	P2.1: Single (No fault line section)
	EHV	P2.2: Single (Bus section)
	EHV	P2.3: Single (Internal Breaker Fault [non-Bus-tie breaker])
P7	EHV, HV	P7.1: Double (Transmission Circuit-Transmission Circuit on common tower

TPL Planning Events

- Inconsistency between members on validity of certain Planning Events
  - Staff Action Item: Work with stakeholders to develop documented method on identification of Planning Events
  - Vetted through TWG for approval

- Staff Recommendation:
  - Staff recommends including P1 for contingencies, P2 events as contingencies for potential constraints, and P7 events for contingencies if included in the list of permanent flowgates

69 kV Constraints

- Current ITP10 process does not consider 69 kV limitations when performing SCUC/SCED process
  - Results in overloads for < 100kV facilities
- RC mostly considers Bulk Electric System
  - TOs request help for 69 kV system
  - 69 kV facilities are incorporated into the market by the use of temporary flowgates
  - ~25 Temporary FGs for 69 kV system currently
- Staff Recommendation:
  - Allow staff to use engineering judgement with feedback from SPP Operations to incorporate temporary flowgates on the 69 kV system into the constraint list
  - Develop proxy constraints for 69 kV issues
    - LODF on 100kV + system for impact on 69 kV
    - Consider GSF for 69 kV facilities
    - Goal is to develop appropriate sized solution (69 kV for reliability or 100 kV+ for economic) for cause of violation
  - Exclude constraints for non-member facilities

Reclassification of Needs

- Constraints can always slip through the cracks
- Sometimes end up as Reliability Needs
- Two examples from the 2017 ITP10
  - Upon identification, staff reconsidered constraints during the Side Bar analysis
  - Reclassified as economic needs
  - One constraints had economic potential, other did not
  - Final project recommendation considered economic evaluation
- Recommendation:
  - Allow staff the ability to evaluate thermal violations observed in the Needs Assessments as constraints for economic consideration
  - May result in reclassification of thermal needs to economic needs

Future Considerations

- Number of constraint files
  - Up to 7 economic models
  - How to handle constraints that do not appear in multiple Years (i.e. Year 2 and Year 5, but not Year 10)
  - Single event file = more constraints/events
  - Bigger event file = longer PROMOD runs
  - Since May 2013: ~13k PROMOD runs , 6-8 hours per run
  - Staging impact for economic projects also a consideration
- Terminal limits
- Identification of new potential stability limits that may precede thermal limitations
- Alternative methods to define planning events
- External planning events
- Feedback loop with DC/AC Conversion as input to final constraint assessment

Certainty	Year 2	Base/Econ&BA Year 5
1	Existing Existing, no TSR	Existing Existing, no TSR
2	(No dispatch in Base*) Approved TSR+GIA	(No dispatch in Base*) Approved TSR+GIA
3	(Dispatch in Base)	(Dispatch in Base)
4	TWG Waiver Criteria SPP Developed Solution to develop solvable model (WG Approval)	TWG Waiver Criteria SPP Developed Solution to develop solvable model (WG Approval)
5	(N-0, N-1) RAR to SPP Staff	(N-0, N-1) RAR to SPP Staff
6	GI, No TSR, PPA RAR to ESWG/TWG	GI, No TSR, PPA RAR to ESWG/TWG
7	Company Planned with siting RAR to ESWG/TWG	Company Planned with siting RAR to ESWG/TWG
8	Company Planned w/o siting	Company Planned w/o siting
9	N/A	SPP Staff Resource Plan

Definitions

Base: base powerflow model. The common planning model replacing the scenario 0 and scenario 5 powerf

BA: SPP balancing authority powerflow model. The AC powerflow model developed from market dispatch s

Econ: economic model. The model developed for annual market dispatch simulations.

Notes

*Applicable to **Base** model only. All resources included in **BA** and **econ** models will be eligible for market dis

All resources meeting criteria for **Base powerflow will be included in **BA** powerflow and **econ** models

Year 10	Notes
Existing	
Existing, no TSR	
(No dispatch in Base*)	
Approved TSR+GIA	
(Dispatch in Base)	
TWG Waiver Criteria	Submittal deadline January WG meetings
SPP Developed Solution	
to develop solvable model	
(WG Approval)	
(N-0, N-1)	Submittal deadline January WG meetings
RAR to SPP Staff	
GI, No TSR, PPA	Submittal deadline January WG meetings
RAR to ESWG/TWG	
Company Planned with siting	Submittal deadline January WG meetings
RAR to ESWG/TWG	
Company Planned w/o siting	Submittal deadline January WG meetings
SPP Staff Resource Plan	

low models.

simulations.

patch


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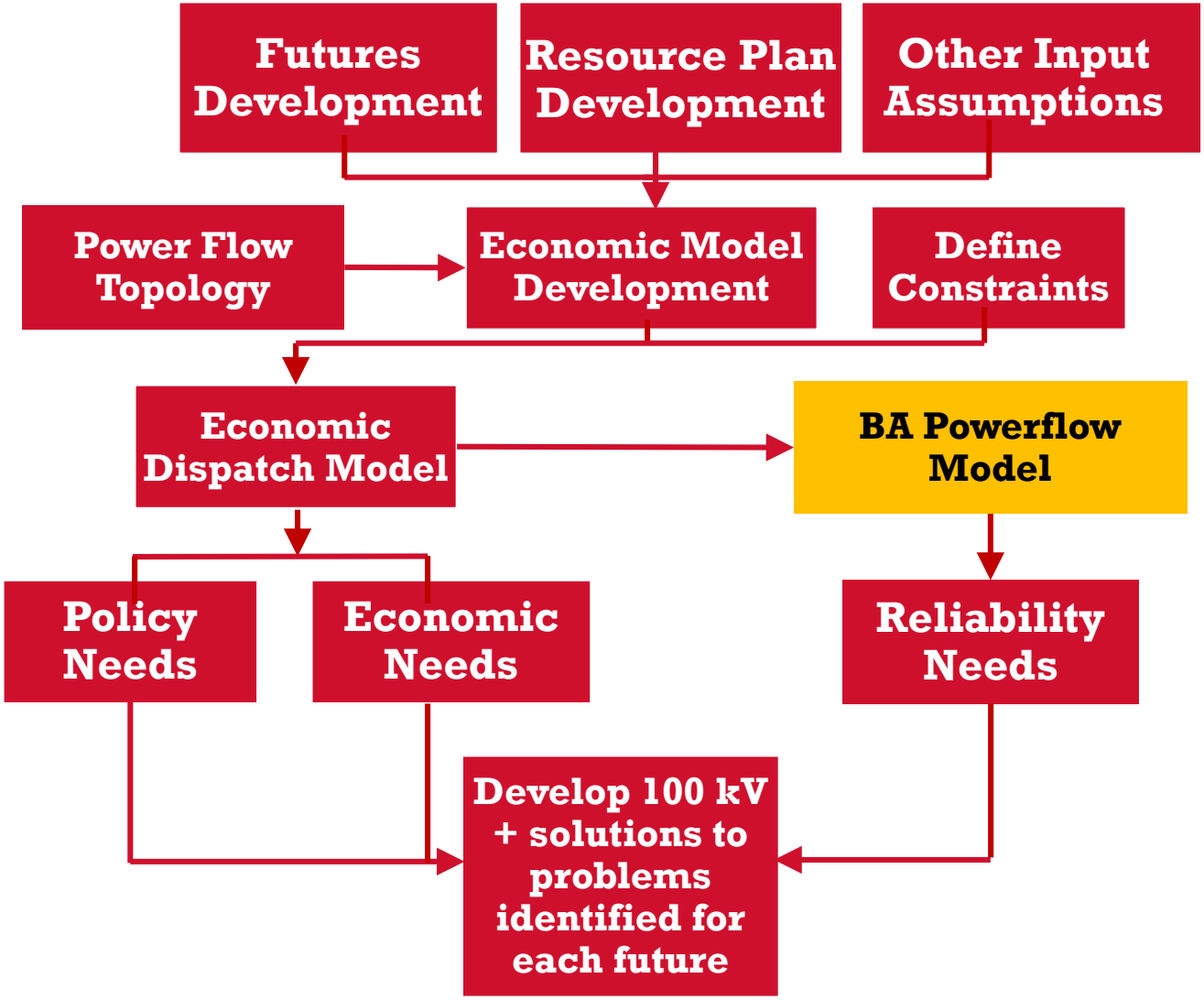
ITP Scope Standardization – DC to AC Model Conversion

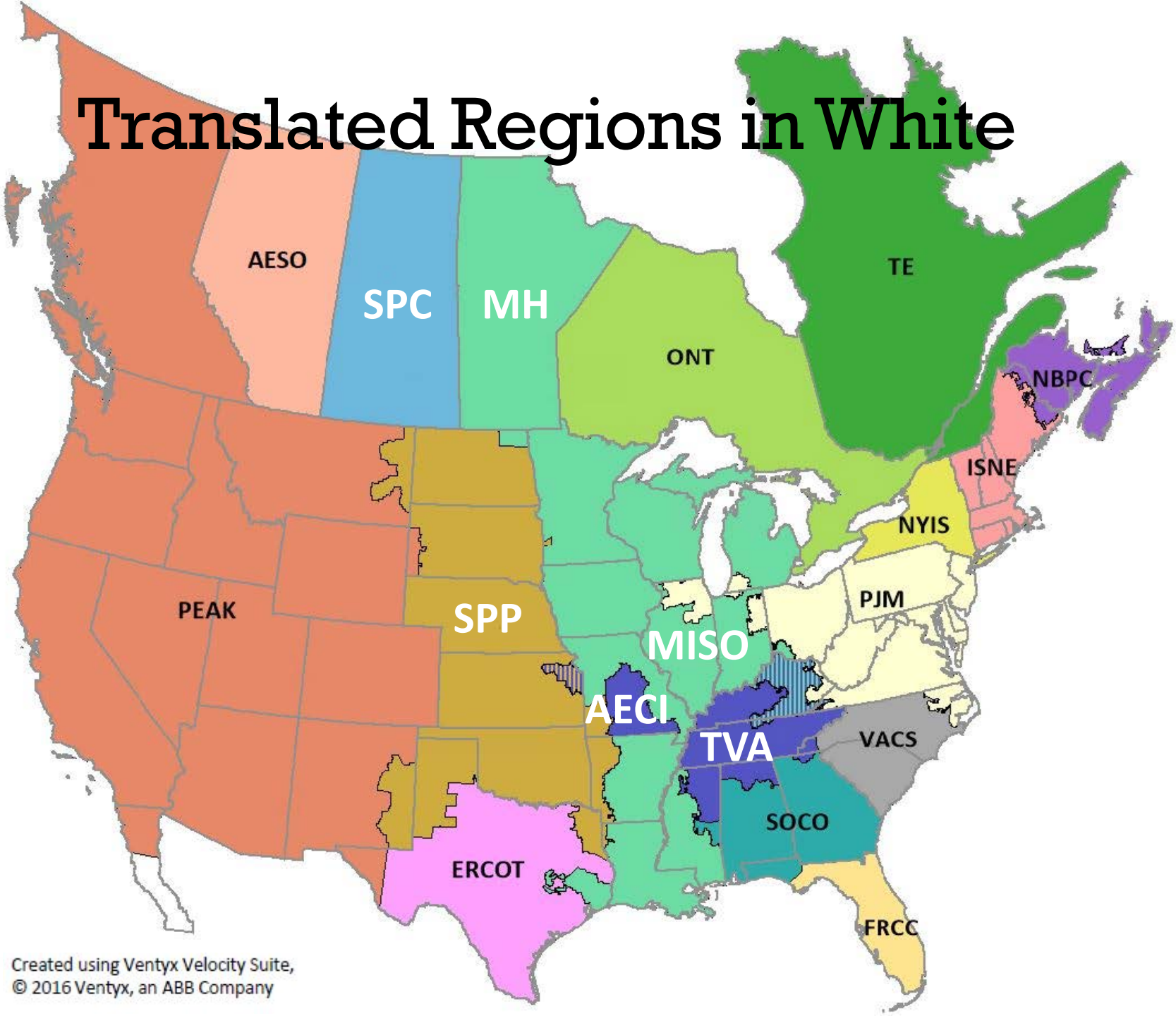
ITP10 Process



DC to AC Model Conversion Process

- Select certain hours out of the year that uniquely stress the SPP transmission system (TWG), typically:
  - Summer Peak
  - Off Peak (highest wind penetration)
- Utilize operating points from the economic (DC) simulation to develop AC powerflow models
  - Coincident load for SPP and other simulated (translated) regions
  - Market dispatch (SCUC/SCED) for translated regions
  - DC line flows
  - PST angles
- Send to stakeholders for reactive device settings review

Translated Regions in White



Issues Background

- SPP staff identified AC overloads in the 2017 ITP10 model set defined as constraints (flowgates) in the DC simulation
- SPP staff recognizes differences in DC economic modeling versus AC powerflow modeling and attributes thermal loading differences to the following:
  - AC versus DC powerflow differences (MW vs. MW/MVAR)
  - System losses modeling differences (approximating transmission losses at the load in DC analysis)
  - External system modeling differences (external transaction assumptions to non-translated regions)
  - Phase-shifting transformer modeling differences (operating parameters)
  - Generator maintenance and forced outage modeling
  - Other differences

Discussion Background

- Not all AC thermal overloads identified in the reliability assessment are true reliability need
- While some AC overloads are valid, PROMOD is built to dispatch around thermal limits
- In theory, thermal issues should only be potential reliability needs if a constraint was not modeled or it was violated by the simulation

2017 ITP10 Approach

- Invalidate thermal AC overloads as reliability needs when defined as a DC constraint
  - Allow for the process to identify economic benefit of relieving economic constraints versus automatically addressing overloads in AC model
  - Assess in future assessments
- Identify AC overloads related to DC constraints for potential invalidation
  - Downstream issues due to AC overload of a binding DC constraint
  - Assess in future assessments
- ESWG Action Item #168
  - [SPP] Staff and the ESWG to evaluate the issues seen in the DC to AC model conversion process.

2017 ITP10 Sidebar Economic Model Adjustments

- External Transaction Modeling
  - Issue: external transactions proxy purchases and sales witn non-translated regions. These are modeled as large injections or withdrawals at EHV buses on the seam of the simulated regions.
  - Adjustment: removed transactions

DC/AC Flow Differences

- SPP staff currently reviewing results and working on summary of EHV line flows
  - AC vs. DC
  - Approved vs. Sidebar

Other Considerations

- Perform security-constrained redispatch (SCRD) or security-constrained economic dispatch (SCED) utilizing TARA after AC powerflow model is developed
- Phase-shifting transformer modeling – process improvement approved by ESWG to better align economic and powerflow operation will improve flow mismatches
- Transmission losses modeling
  - Issue: transmission losses are approximated as a % of company peak and grossed up at the load causing a potential divergence from actual losses calculated by AC solution and thus generation dispatch required to
  - Potential solution: utilize PROMOD transmission loss approximation to acquire generation dispatch

Other Considerations

- Translated region scope
  - Issue: differences in flows on large EHV lines appear to be greater the closer the lines are in proximity to the edge of the translated system
  - Potential solution: expand the scope of simulated regions (e.g. PJM, SOCO)
- Non-translated powerflow modeling
  - Issue: generation in non-translated regions is scaled up to match non-translated load for the duration of the simulation. This is not done in the BA powerflow model as external transactions are expected to be a proxy for imports/exports to non-translated regions
  - Potential solution: adjust non-translated load and/or generation prior to economic model simulation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ITP Scope Standardization – Transmission Topology Modeling

Background

- Economic assessments historically utilize a single transmission topology model during an annual simulation
- ITP reliability and TPL compliance assessments historically utilize multiple seasons within a year, potentially reflective of different transmission topologies
- Goal: determine methodology to accommodate an expected changing transmission topology within a single study year.
  - Consistency vs. status quo
  - Types
    - Modeled long-term transmission outages
    - Future transmission upgrades in-service mid-year

Consideration of Impacts

- Long-term transmission outages
  - Modeling could potentially drive the need for transmission projects in ITP assessments
  - Not modeling could potentially mask the need for a corrective action plan (CAP) in TPL assessments
- Future transmission upgrades in-service mid-year
  - Modeling could mask need to accelerate certain approved projects
  - Not modeling could drive needs that are expected to be resolved without adjustment of an existing NTC

Modeling Options - Consistency

- Build reliability models to reflect system topology utilized in annual economic assessment
  - Pros
    - Gain consistency between models
    - Avoid developing upgrades for long-term transmission outages
  - Cons
    - Will not identify potential violations requiring CAP for TPL
    - Will not identify potential project acceleration needs within year
    - No base consideration of late-year upgrades that could resolve identified needs
- Build economic model to reflect system topology of base scenario model seasons in a given year
  - Pros
    - Gain consistency between models
    - More accurate expected topology
    - Will identify potential violations requiring CAP for TPL
    - Will identify potential project acceleration needs within year
  - Cons
    - Time-intensive economic modeling effort
    - Increased economic simulation times
    - Potentially infeasable
    - Potentially recommend upgrades based on long-term outages

Modeling Option - Status Quo

- Pros
  - Best combination of consistency, feasibility and model accuracy
- Cons
  - Inconsistency of transmission topology between economic and base reliability models for a given year
  - Inconsistency of transmission topology between base scenario reliability and BA reliability models depending on selected hour (ITP10 process)
  - No consideration of late-year upgrades in base economic assessment
    - Historically not an issue due to economic assessments being performed in 10th or 20th year only (all planned upgrades in-service prior to 10th year)
  - Developing transmission solutions for long-term outages
    - Historically, few long-term transmission outages have been identified
  - Other

Transmission Topology Modeling Recommendation

Modified Status Quo

- Long-term transmission outages
  - Include in base reliability models
    - Satisfies TPL requirements
    - Need to recognize when needs are driven by outages in ITP solution development
  - Do not include in BA reliability and economic models
    - Satisfies TPL requirements

- Mid-year transmission upgrades in-service dates
  - As expected in-service dates for base reliability models


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2017 ITP10 Potter to Tolk 345 kV Additional Analysis

February 15,2017

Overview

- Additional analysis in response to stakeholder concerns and action taken by Board of Directors
- Discussions with directly impacted stakeholders to acquire input
- ESWG and TWG vetting prior to April MOPC and BOD meeting
- Review of third party study estimate
- Other reasonable economic model input assumption sensitivities
  - Gas prices
  - Renewable additions
  - Conventional resource assignment and siting sensitivities
  - Constraint file adjustments
- Substantiating future avoided reliability projects
  - SPS vetting
  - FCITC analysis
  - SPS load pocket trends
- Assess impact of line on Frequently Constrained Area (FCA) designation of Texas Panhandle
- 40-year benefit calculations
- Additional voltage stability assessments (Optional)
- LOLE sensitivity (Optional)