Southwest Power Pool

JOINT TRANSMISSION & ECONOMIC STUDIES WORKING GROUP MEETING

June 29, 2017

SPP Corporate Campus – Little Rock, AR

• Summary of Action Items •

1. Approved the Resource Siting Manual (TWG & ESWG)
2. Approved the ITP Manual (TWG & ESWG)
3. Approved joint ownership of the ITP Manual in the Revision Request process (TWG)

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• M I N U T E S •

Agenda Item 1 – Administrative Items

TWG Chair Travis Hyde and ESWG Chair Alan Myers called the meeting to order at 8:35 am. The following members were in attendance (Attachment 1a – Attendance):

TWG
Travis Hyde (Chair), Oklahoma Gas & Electric
Scott Benson, Lincoln Electric System
John Boshears, City Utilities of Springfield
Eric Burkey, South Central MCN
John Fulton, Southwestern Public Service Company
James Ging, Kansas Power Pool
Kalun Kelley, Western Farmers Electric Cooperative
John Knofczynski, East River Electric Power Cooperative
Dan Lenihan, Omaha Public Power District
Randy Lindstrom, Nebraska Public Power District
Jim McAvoy, Oklahoma Municipal Power Authority
Matt McGee, American Electric Power
Nate Morris, Empire District Electric
Michael Mueller, Arkansas Electric Cooperative Corporation
Alan Myers, ITC Great Plains
Gayle Nansel, Western Area Power Administration
Dona Parks, Grand River Dam Authority
John Payne, Kansas Electric Power Cooperative
Jeremy Severson, Basin Electric Power Cooperative
Jason Shook, GDS Associates representing ETEC
Brian Wilson, Kansas City Power & Light

ESWG
Alan Myers (Chair), ITC Great Plains
Eric Burkey, South Central MCN
Randy Collier, City Utilities of Springfield
Don Frerking, Kansas City Power & Light
Natasha Henderson, Golden Spread Electric Cooperative
Leon Howell, Oklahoma Gas & Electric
Jon Iverson, Omaha Public Power District
Gayle Nansel, Western Area Power Authority
Tim Owens, Nebraska Public Power District
Anita Sharma, American Electric Power
Jeremy Severson, Basin Electric Power Cooperative
Kurt Stradley, Lincoln Electric System
Michael Watt, Oklahoma Municipal Power Authority

Kirk Hall and Kelsey Allen, both SPP staff, informed the Chairs of a quorum for their respective groups.

Receipt of Proxies
The following proxies were announced (Attachment 1b – Proxies):

TWG
- Eric Burkey (SCMCN) proxy for Noman Williams (SCMCN)
- Dona Parks (GRDA) proxy for Joe Fultz (GRDA)
- Brian Wilson (KCP&L) proxy for Harold Wyble (KCP&L)
- Jeremy Severson (BEPC) proxy for Matthew Stoltz (BEPC)

ESWG
- Eric Burkey (SCMCN) proxy for Jody Holland (SCMCN)
- Don Frerking (KCP&L) proxy for Pat McCool (KCP&L)

Agenda Item 2 – Consent Agenda

Travis and Alan asked if any TWG or ESWG members preferred discussion on the Consent Agenda (Attachment 2a – Resource Siting Manual). Members did request that the Resource Siting Manual be pulled from the consent agenda and discussed prior to approval. Stakeholders had some concerns with an incomplete version of the Resource Siting Manual being referenced in the ITP Manual as well as felt more information from the Resource Siting Manual should be included in the ITP Manual. After some discussion staff and the stakeholders agreed that the ITP Manual could be adjusted to address one concern.

> **Motion (ESWG): Natasha Henderson made a motion to approve the Resource Siting Manual as draft with the creation of an action item to complete the manual. Leon Howell seconded the motion. The motion was approved unanimously.**
>
> **Motion (TWG): Alan Myers made a motion to approve the Resource Siting Manual as draft with the creation of an action item to complete the manual. Jason Shook seconded the motion. The motion was approved unanimously.**
>
> **Action Item: Staff and working groups will work together to complete the Resource Siting Manual.**

Agenda Item 3 – ITP Manual

Model Naming Convention
Prior to reviewing the manual Kirk asked the stakeholders if they had any concerns with renaming the models (Attachment 3a – Standard ITP Model Names) discussed in the ITP Manual to better describe what each model type contains. Due to the limited amount of time the members had to consider the potential new names for the different planning models, they did not want to approve a change to the naming convention of the models. They preferred to see the change come in the form of a revision request as well as including a description of each model type.

Manual Approval
Amber Greb, SPP staff, reviewed the ITP Manual change summary (Attachment 3b, 3c – Revisions Summary, ITP Manual Redlines) since original materials posting and took questions from the group. Some members expressed general concern that the manual being requested for approval had many last minute redline changes without ample time to review. Staff requested the TWG and ESWG's opinion on a few topics such as listing the process/milestone ownership section and the history sections included in the manual. Both groups felt the information should be included.

Steve Gaw, Wind Coalition, expressed objections to the renewable pricing methodology outlined in the manual, specifically that the reflection of a contract price in the operating costs of renewables is discriminatory when compared to assumptions included for resources of other types. Rodica Donaldson,

EDF Renewable Energy, echoed Steve's objections and added that those contract prices include cost unrelated to the operating and maintenance costs of the renewable generators and should not be included in the economic model. Kelsey acknowledged those concerns and stated that the methodology outlined in the manual was previously approved by the ESWG, but these issues would continue to be discussed. Natasha Henderson expressed concern regarding the requirement of entities to provide documentation of contract price agreements in order to reflect those prices for renewable units in the model, specifically the potential for entities to choose whether or not to provide the information depending on what benefits them the most.

> **Motion (ESWG): Kurt Stradley made a motion to approve the ITP Manual as modified during the meeting with the allowance for non-substantive edits and moving the History of the ITP and TPITF section to an appendix. Jon Iverson seconded the motion. The motion passed unanimously.**
>
> **Motion (TWG): Alan Myers made a motion to approve the ITP Manual as modified during the meeting with the allowance for non-substantive edits and moving the History of the ITP and TPITF sections to an appendix. Scott Benson seconded the motion. The motion passed unanimously.**

Manual Ownership

Kirk discussed with the group the inclusion of the ITP Manual in the RR process. He informed both groups how the process works when a new document is added to the process and the current primary working group for the manual had been identified as the TWG due to the fact the TWG is already a primary working group. The ESWG would be identified as a 'PS' working group in the RR Routing Criteria on those sections that should be owned by the ESWG. Using this ownership model, the ESWG would maintain ownership over the sections that were economic in nature, and the main impact would be on the staff secretaries who were working the revision requests through the process. Kirk told the members he wanted to give the opportunity to the ESWG and TWG to voice their concerns over the ESWG not being considered as a Co-Primary Working Group for the ITP Manual along with the TWG. Multiple ESWG members expressed their concerns with the ESWG not being a Primary owner. The TWG agreed with the ESWG concerns.

> **Motion (TWG): John Boshears made a motion to split the ownership of the ITP Manual in the Revision Request Process with the ESWG. Alan Myers seconded the motion. The motion passed without opposition.**

Agenda Item 4 – High Priority Study Overview

Kelsey updated the group on the progress of the High Priority Study scope development. He reviewed a presentation (Attachment 4 – High Priority Study) he gave to the Strategic Planning Committee and recapped the discussion that followed. He also discussed an alternative proposal suggested by AEP that could be an alternative method to address the current congestion issues. Travis Hyde expressed concerns with the cost and timeline of performing the study as proposed, stating that the original request from the Board was to only analyze the issues in the panhandle of Texas. Both groups asked for updates after the upcoming MOPC and Board meetings.

Respectfully Submitted,

Kirk Hall
TWG Secretary

Kelsey Allen
ESWG Secretary

ECONOMIC STUDIES WORKING GROUP/TRANSMISSION WORKING GROUP

June 29th, 2017

Net Conference

• A G E N D A •

8:30am – 11:30am

1. Administrative Items
    a. Call to Order, Introductions.....Alan Myers/Travis Hyde
    b. Receipt of Proxies .....Kelsey Allen/Kirk Hall
2. Consent Agenda[1] (Approval Item).....Alan Myers/Travis Hyde
    a. Resource Siting Manual
3. ITP Manual[1] (Approval Item) ..... Amber Greb (120 minutes)
    a. Model Naming Convention
    b. Manual Approval
    ~~b.~~c. Manual Ownership
~~3.~~4. 2018 High Priority Study Scope[1] ..... Kelsey Allen (60 minutes)

[1] Background Materials Included

All sessions in Central Daylight Time (Chicago, GMT-05:00)

Session detail for 'ESWG/TWG Net Conference':

Participant	Name	Email
1	Shawnee Claiborn-Pinto	shawnee.claiborn-pinto@puc.texas.gov
2	Michael Wegner (ITC)	mwegner@itctransco.com
3	Sherri Maxey	smaxey@spp.org
4	Steve Hardebeck-OGE	hardebsm@oge.com
5	John Turner (BPU)	jturner@bpu.com
6	Josh Verzal (OPPD)	jverzal@oppd.com
7	Michael Wegner (ITC)	mwegner@itctransco.com
8	Jim McAvoy	jmcavoy@ompa.com
9	Jeff Knottek	jeff.knottek@cityutilities.net
10	Tim Owens (NPPD)	tjowens@nppd.com
11	Matt McGee	mcmcgee@aep.com
12	Jordan Schmick	jordan.h.schmick@xcelenergy.com
13	Jamie Hajek	jamie.hajek@northwestern.com
14	Aaron Shipley	ashipley@spp.org
15	Kalun Kelley (WFEC)	k_kelley@wfec.com
16	ed pfeiffer (quanta)	epfeiffer@quanta-technology.com
17	Natasha Henderson	nhenderson@gsec.coop
18	Jeremy Severson	jseverson@bepc.com
19	Jason Mazigian	jmazigian@bepc.com
20	Kurt Stradley (LES)	kstradley@les.com
21	Evan Racine-Johnson (GSEC)	eracine-johnson@gsec.coop
22	David Silver	dwsilver@aep.com
24	Kevin Foflygen (SPRM)	kevin.foflygen@cityutilities.net
25	Jeremy Harris (Westar)	jeremy.harris@westarenergy.com
26	Nikki Roberts	nroberts@spp.org
27	Jason Shook (GDS/ETEC)	jason.shook@gdsassociates.com
28	Josie Daggett	daggett@wapa.gov
29	Michael Wegner (ITC)	mwegner@itctransco.com
30	Bill Leung (NPRB)	bleung@bjleung.com
31	Brooke McMillan	bmcmillan@spp.org
32	Mounika Kurra (Quanta)	mkurra@quanta-technology.com
33	David Sargent	dave.sargent@swpa.gov
34	Nathan McNeil	nmcneil@mwenergy.com
35	Travis Hyde	hydetd@oge.com
36	Randy Lindstrom	rrlinds@nppd.com
37	Steve Gaw	rsgaw1@gmail.com
38	Steve Gaw	rsgaw1@gmail.com
39	John Knofczynski	jknofczynski@eastriver.coop
40	Chris Jamieson	cjamieson@spp.org
41	Zac Hager	hagerzc@oge.com
42	Bill Leung (NPRB)	bleung@bjleung.com
43	Scott Benson (LES)	sbenson@les.com
44	Brian Fleming (SPS)	brian.fleming@xcelenergy.com
45	reene miranda	rene.miranda@xcelenergy.com

46	Sherri Maxey	smaxey@spp.org
47	Brian Wilson	brian.wilson@kcpl.com
48	Joshua Tupper - EDE	jtupper@empiredistrict.com
49	John Payne (KEPCo)	jpayne@kepco.org
50	shawn szydlik	shawn.m.szydlik@leidos.com
51	Alan Myers	amyers@itctransco.com
52	Michael Watt (OMPA)	mwatt@ompa.com
53	Dan Lenihan	djlenihan@oppd.com
54	Michael Mueller	michael.mueller@aecc.com
55	James Ging (KPP)	jging@kpp.agency
56	Jim Jacoby (AEP)	jwjacoby@aep.com
57	Brian Johnson - AEP	bajohnson1@aep.com
58	Chenal WebEx	awhite@spp.org
59	Dee Edmondson	dedmondson@spp.org
60	Adrienne Blaine	adrienne.blaine@wfec.com
61	Aravind Chellappa (SPS)	aravind.chellappa@xcelenergy.com
62	Jerry Bradshaw (SPRM)	jerry.bradshaw@cityutilities.net
63	Marisa Choate	mchoate@spp.org
64	John Fulton	john.fulton@xcelenergy.com
65	Don Frerking (KCP&L)	don.frerking@kcpl.com
66	Leon Howell	howelllc@oge.com
67	Ryan Yokley	ryokley@sunflower.net
68	Mounika Kurra (Quanta)	mkurra@quanta-technology.com
69	Ashley Swain	aswain@spp.org
70	Chris Colson (WAPA-UGPR)	colson@wapa.gov
71	John Boshears (SPRM)	john.boshears@cityutilities.net
72	Dona Parks (GRDA)	dparks@grda.com
73	Scott Mijin	scott.mijin@swpa.gov
74	Brian Rounds (AESL)	brian.rounds@aeslconsulting.com
75	Randy Collier (CUS)	randy.collier@cityutilities.net
76	Jason Speer	jspeer@spp.org
77	Gimod Olapurayil	golapurayil@itctransco.com
78	Gayle Nansel	nansel@wapa.gov
79	Steve Hohman (OPPD)	shohman@oppd.com
80	Tyler Baxter	tyler.baxter@cbpower.coop
81	Becky Turner	rturner@cleanlineenergy.com
82	Sam Zewdie	ss.zewdie@midwestreliability.org
83	Kelsey Allen	kallen@spp.org
84	Anita Sharma (AEP)	asharma@aep.com
85	Clayton (SPP staff)	cmayfield@spp.org
86	Nate Morris (EDE)	nmorris@empiredistrict.com
87	Rodney Massman	rodney.massman@psc.mo.gov
88	Jarrod Wolford (NTEC)	jwolford@ntecpower.com
89	Jon Iverson	jiverson@oppd.com
90	Jason Chaplin (OCC)	j.chaplin@occemail.com
91	Ben Abing	babing@itctransco.com
92	eric burkey	eburkey@gridliance.com

93	Rodica Donaldson	rodica.donaldson@edf-re.com
94	John Varnell	jvarnell@tnsk.com
95	Derek Brown	derek.brown@westarenergy.com
96	Ross Hohlt	dhohlt@ameren.com

Kirk Hall

From: McCool, Patrick
Sent: Tuesday, June 20, 2017 9:13 AM
To: Myers, Alan; Kelsey Allen
Cc: Frerking, Don
Subject: **External Email** Proxy

Alan/Kelsey,

I'll miss the June 29th call, so I'd like to give my proxy to Don Frerking.

Thanks, Pat

Kirk Hall

From: Myers, Alan
Sent: Wednesday, June 28, 2017 7:00 AM
To: Holland, Jody
Cc: Eric Burkey; Eric Burkey; Kelsey Allen
Subject: **External Email** RE: [EXT] FW: ESWG/TWG 6/29/17 Agenda & Background Materials posted

Ok. Thanks Jody. We'll note for the minutes.

From: Jody Holland [mailto:JHolland@gridliance.com]
Sent: Tuesday, June 27, 2017 5:19 PM
To: Myers, Alan K. <amyers@ltctransco.com>
Cc: Eric Burkey <EBurkey@gridliance.com>; Eric Burkey <EBurkey@gridliance.com>
Subject: [EXT] FW: ESWG/TWG 6/29/17 Agenda & Background Materials posted

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Alan,
Eric has my proxy for this joint ESWG/TWG call. Thanks.

Jody Holland
Vice President, Planning
South Central MCN, LLC
Midcontinent MCN, LLC
MidAtlantic MCN, LLC
Gridliance West Transco, LLC
Cell: 501-681-5950
jholland@gridliance.com

GridLiance, a Blackstone Portfolio Company
2 N. LaSalle Street, Suite 420
Chicago, IL 60602
www.gridliance.com

Kirk Hall

From: Fultz, Joe
Sent: Wednesday, June 28, 2017 12:56 PM
To: Kirk Hall; Hyde, Travis
Cc: Parks, Dona
Subject: **External Email** TWG/ESWG mtg on the 29th

Dona Parks will have my proxy for the TWG/ESWG meeting tomorrow.

Thanks.

Joe Fultz
GRDA Engineering Operations
(918) 824-7884

Kirk Hall

From: Wyble, Harold
Sent: Tuesday, June 27, 2017 2:14 PM
To: Kirk Hall; Hyde, Travis
Cc: Wilson, Brian
Subject: **External Email** TWG meeting 6-29-17

Brian Wilson will have my TWG proxy for the ESWG/TWG meeting on Thursday, June 29.

Harold Wyble
Manager Transmission Planning
Kansas City Power & Light
816-654-1213

Kirk Hall

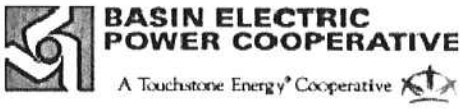
From: Stoltz, Matthew
Sent: Tuesday, June 27, 2017 1:27 PM
To: Kirk Hall
Cc: Severson, Jeremy
Subject: **External Email** TWG Proxy

Kirk,

I will not be able to participate in the TWG/ESWG call on Thursday. Jeremy will be my proxy.

Thanks,

Matthew Stoltz, P.E.
Director, Transmission Services
Basin Electric Power Cooperative
1717 E Interstate Ave
Bismarck, ND 58503
e-mail: mstoltz@bepc.com
phone: 701.557.5647
web: basinelectric.com



Kirk Hall

From: Kelley, Kalun
Sent: Tuesday, June 20, 2017 8:43 AM
To: Kirk Hall
Cc: Dunham, Nigel
Subject: **External Email** PROXY: TWG 6/21/17 Agenda & Background Materials posted

Kirk,

WFEC BOT meeting is tomorrow and I will not be available for all of the TWG meeting (I will participate when I can), so I will be giving my proxy to Nigel Dunham on behalf of WFEC.

Thanks,
Kalun

From: bounce-57753-122573@spplist.spp.org [mailto:bounce-57753-122573@spplist.spp.org] **On Behalf Of** Audrey White
Sent: Wednesday, June 14, 2017 5:58 PM
To: Transmission Working Group <twg@spplist.spp.org>
Subject: TWG 6/21/17 Agenda & Background Materials posted

TWG 6/21/17 Agenda & Background Materials have been posted to the SPP website for your review at the link shown below:

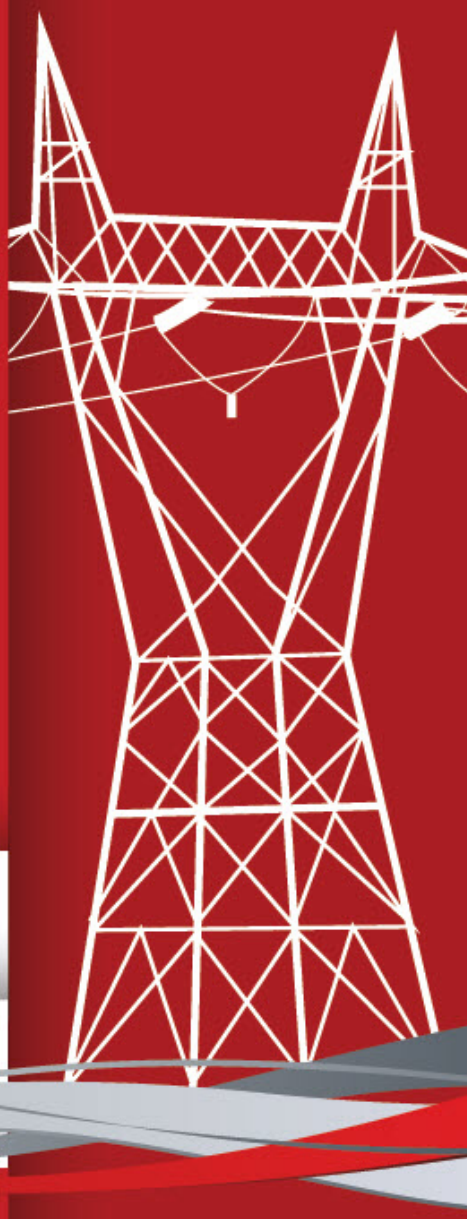
TWG Meeting Materials

TWG 6/21/17 Online Registration

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

INTEGRATED TRANSMISSION PLAN RESOURCE SITING MANUAL

SPP Southwest Power Pool



REVISION HISTORY

Date	Author	Change Description
06/20/2017	SPP staff	Initial Creation

TABLE OF CONTENTS

SECTION 1:RESOURCE SITING PROCESS

1.1: Introduction

Both phases of the resource plan will identify necessary resource additions. The resources will be sited in order to meet study objectives in areas with appropriate potential pursuant to the guidelines established herein. The sites will be developed utilizing sites selected in previous studies, the generation interconnection (GI) queue, and sites developed by SPP staff and stakeholders using specific resource technology information. SPP staff will give stakeholders ample opportunities to provide feedback throughout the process and will directly engage stakeholders as needed to ensure that siting assumptions are reasonable. The siting effort will be conducted as a screening level exercise to identify sites that generally comply with the criteria and will not be intended to provide or replace a fully scoped power plant siting study. A physical spatial location and electrical point of interconnection for each new resource within the SPP region will be selected. The new resources will be spatially located within the SPP with the aid of the following:

- GI queue and studies
- Geographic information system (GIS) databases showing locations of transmission lines, natural gas pipelines, railroads, waterways, substations, and current land use
- Repositories of prior study sites and conceptual sites
- Stakeholder feedback and surveys
- Public Policy information
- Environmental maps and data
- NREL datasets, studies and information on renewable potential
- Load density maps
- Load pocket information and studies
- Historic congestion and energy prices
- Other data specific to each resource technology

The point of interconnection for new resources will be determined based on the following:

- GI queue and studies
- Scope and scale of generation leads
- Nearby substations with the best Available Transfer Capability (ATC)
- Transmission interconnection feasibility of existing substations

- New substation requirements to access existing transmission lines nearby
- Voltage level of interconnection
- Distribution interconnection feasibility for smaller sized renewable resources

1.2: Site Repository

A site repository will be developed and maintained for each resource type to track sites, usage, suitability attributes, prioritization, and stakeholder feedback from study to study. The repository will be provided to stakeholders throughout the siting process for review to provide additional sites for consideration and targeted feedback. The repository will include sites from prior studies, GI queue, and additional conceptual sites. Each site will be classified by technology type and include applicable qualitative and quantitative site suitability attributes and qualifications to rank and choose sites and build confidence in the siting plan. The repository will consider existing and retired generation sites, GI queue sites, and conceptual greenfield sites that will periodically be removed or adjusted to account for actual resource development.

The site repository could include, but is not limited to:

- Spatial location of site (GPS location)
- Electric location of site (bus, bus kV, bus name)
- Site pricing zone, state, nearest town, and county location
- Amounts and dates of expected generation retirements
- First-Contingency Incremental Transfer Capability (FCITC) analysis results that prescreen generator outlet capability and/or deliverability of new resource to the SPP footprint
- GI queue number, point of interconnection, status, interconnection costs, and available capacities
- Stakeholder survey results
- Site classification such as brownfield, retired, or greenfield sites
- Source of site (provided by SPP staff or stakeholder)
- SPP staff and stakeholder prioritization of site and rationale
- Location in relation to modes of fuel transportation (railroad, navigable waterway, gas pipeline, etc.)
- Location in relation to Frequently Constrained Areas (FCA), load pockets, load centers, and historic congestion
- Renewable resource capacity factors

- Fuel supply, substation interconnection, and air permitting feasibility
- Available land and feasibility of changes in land use
- Historic LMPs
- SPP staff and stakeholder feedback and comments
- Other items as needed to ensure that sites have been properly vetted by SPP staff and stakeholders

1.3: General Siting Philosophy

The siting philosophy for new resources will incorporate the following general guidelines:

- Understand study objectives and how best to select practical sites to enable a study's ability to assess transmission system limitations
- Avoid excessive concentration of generation in one unit, at one location, or in one area in order to maintain a balanced design of the electric system
- Recognize that proxy generation and generator outlet facility assumptions can unintentionally mask critical transmission needs and can hinder the study's ability to assess transmission system limitations
- Site new jointly owned resources in the pricing zone or state of operation of entities with the highest capacity need unless it hinders the study's ability to assess transmission system limitations or there is substantiating evidence to support otherwise, such as a limited amount of suitable sites or more attractive sites elsewhere
- Use transmission availability and resource deliverability to rank site alternatives and minimize generator outlet facility assumptions
- Maintain a reasonable balance of remaining renewable technical potential across SPP system
    - Consider areas of the system with insufficient transmission availability to prevent from having trapped generation potential
- Limit siting of low cost resources near load centers
- Limit conventional site capacity to less than 1,500 MW

1.4: General Prioritization and Ranking

A priority based approach to siting new resources will generally be used to provide a logical order to locating generation. The prioritization will begin by ranking prospective new resource sites by data source and site category. The source of prospective new resource sites will be the GI queue, stakeholders, SPP staff, and publically available information. The prioritization and ranking criteria and siting results may be changed as needed from study to study to meet the specific objectives of each study to best deal with evident risks and uncertainties presented by trapped generation potential, load pockets, bulk transfers, and other transmission limits of interest on a case by case basis. The final resource siting plan should result in a practical balance of resource additions across SPP in such a way

that the study can investigate and solve transmission limitations to best benefit the region. The prioritization and ranking criteria will be based on both objective and subjective information and approved by stakeholders.

GI Queue

Preference will be given to sites in the GI queue. The generators will be ranked according to their status. The GI queue prescreens obstacles such as transmission capacity availability, land availability, and customer interest due to incentives or opposition. Listed below are the statuses, ranked from high to low:

- Interconnection agreement (IA) fully executed/Commercial Operation – The Generator Interconnection Agreement (GIA) is executed and the project has achieved commercial operation.
- IA fully executed/Commercial Operation not fully on-line – This is not a SPP GI Queue status. The GIA is executed and the project has achieved commercial operation for a portion of the requested capacity. Subsequent phases of the project may have a later operational date.
- IA fully executed/on**-** schedule – The GIA is executed and the agreement milestones are being met.
- IA fully executed/on**-** suspension – The GIA is executed however the GI customer has requested that facility construction work be suspended.
- IA pending – The facility study is completed for the GI request. SPP, the interconnection customer, and the transmission owner(s) (TOs) are negotiating and drafting the GIA.
- Facility Study Stage – The system impact study has completed for the GI request. The TOs are further studying the required facilities.
- Definitive Interconnection System Impact Study
- Preliminary Interconnection System Impact Study
- Withdrawn

GI customers and/or applicable TOs will be surveyed, as needed, to gather information regarding prospective generation in the GI queue. The objective of the survey will be to better understand the likelihood of a resource proceeding to full commercial operation and will aid in the prioritization. The GI queue site priority and ranking will be adjusted, as needed, to meet study objectives, prevent from having load pocket and trapped generation potential issues, and allow the study to assess transmission system limitations and transmission solutions that may have regional economic and reliability benefits. Other information such as IA milestone and market registration progress, historic average costs to interconnect, local incentives, local opposition and historic congestion and energy prices may be used to adjust the rank of GI queue sites with equal or lower GI queue statuses. GI queue sites with less certain statuses will be given equal priority to sites provided by stakeholders, SPP staff, and publically available information considering site suitability qualities, impact to the system, market impact, or likelihood of commercial operation.

Renewables

The renewable GI queue sites will be ranked by queue status, capacity factor, survey results, and transmission interconnection cost. The GI queue sites will be selected from the ranked list, while maintaining a reasonable balance in remaining renewable technical potential across the SPP system. This may involve selecting conceptual renewable sites not in the GI queue or excluding any significant GOFs associated with sites needed to help maintain this balance. GOFs intentionally ignored may require additional criteria and analysis to allow the study to assess transmission system limitations and transmission solutions. The information, criteria, and methods used to maintain this balance will be discussed with the ESWG to determine the reasonableness of assumptions.

Site Categories

Each site will be categorized and additionally ranked as follows:

1. Existing Brownfield sites
    1.1. With scheduled retirements
    1.2. With projected retirements
    1.3. Without retirements
2. Mothballed or Retired Brownfield sites
3. Greenfield sites
    3.1. Cancelled or postponed projects
    3.2. Conceptual projects

Existing brownfield sites include existing power plants in operation that are expandable and may have some or all units scheduled or projected for retirement. Retired/mothballed brownfield sites include power plants which have not been reused and could be recommissioned. Not all of these brownfield sites may be ideal for new capacity or differing technology. GIS information and stakeholder feedback will be used to help assess feasibility and prioritization of these sites. Generators needed for the study that would require a change in technology at brownfield sites will be given less priority than those where the technology would be the same. Greenfield sites are conceptual sites with no existing or planned development. Generators analyzed in the GI process at greenfield sites that were cancelled or postponed will be given more priority. The reasons why a project was cancelled will be investigated to determine the site's viability relative to other sites.

Transmission Availability

Transmission availability and resource deliverability will be used to rank sites and to limit generator outlet facility assumptions. Generator outlet facility assumptions can be avoided by either selecting another site of equal stature or changing the point of interconnection to one with greater available transfer capability. The siting process will include performing DC FCITC analysis as needed to help develop conceptual sites, prescreen generator outlet facility requirements, and prioritize sites.

Site Assignment

Conventional and renewable sites will be ranked by pricing zone, state, sub-region and region. The sites will be assigned based on the origin of a need for a new resource and criteria that can be applied uniformly across SPP and adjusted as needed to meet study objectives. Resource needs are generally determined by pricing zone but may be determined geographically by state, sub-region, or region, or by utility type and size to mimic joint participation and ownership practices of smaller and larger utilities. Generation will be located in an entity's pricing zone or state(s) of operation. However, attractive sites in other areas can and will be used if they present a cost effective advantage to sites within the entity's zone or state(s) of operation or to balance new resource additions across SPP. This matching of need to site is performed with the goal of spreading out the best sites and meeting study objectives. The criteria and exceptions to assumed ownership and selection of sites will be discussed with the ESWG and directly impacted stakeholders to determine the reasonableness and impact of assumptions.

Load Pocket Analysis

A ranked list of load pockets will be developed and maintained using information from historic studies and system operation, load density maps, and stakeholders. Generation, load, and generation to load profile ratios of the top ranked load pockets will be reviewed as needed to ensure reasonable balances in generation and load[1]. Criteria will be developed and approved by stakeholders to determine when not to site new generation near these load pockets. Both conventional and renewable resource additions and sites may be adjusted to prevent from having potential load pocket issues and allow the study to assess transmission solution alternatives. Adjustments may include but not limited to:

- Selecting a site remote from a load pocket over a site near a load pocket
- Excluding a new resource addition
- Changing the technology of a new resource addition near a load pocket
- Assuming less aggressive growth in renewable resource additions near a load pocket

These adjustments may require additional analysis to be scoped as part of the study such as comparing transmission solutions to new generation as a non-transmission solution. Careful consideration will be given to a load pocket's real and reactive power requirements to identify any need for new generation to provide local voltage support.

[1] See Appendix 5.4: List of Studies with Identified Load Pockets and Load Density Map Example

Additional Expectations

Stakeholders and SPP staff will supply new generation sites for consideration along with site suitability information and ranking relative to other sites in the site repositories. A combination of brownfield and greenfield sites will be selected to ensure balance and diversity in site types and locations. Other quantitative and qualitative information such as expected costs, impact to the system, market impact, and likelihood of commercial operation will be considered in prioritizing and ranking sites. Information gathered from stakeholders will include, but is not limited to, preferred ranking and applicable site suitability qualities. Conventional site suitability should include information such as access to land, air permitting, cost effective fuel delivery and supplies, cooling water, substation interconnection feasibility and site construction logistics to limit interruptions to current site operations.

1.5: Process Flow

The siting process will generally adhere to the following steps:

- Update the site repositories with the latest power flow and GI queue information to account for actual resource development between planning cycles
- Post repositories and request applicable stakeholders to provide feedback and additional sites for consideration and supportive rational
- Assess whether the site repositories include adequate and diverse amount of sites to fulfill the requirements of the resource plan and are representative of remaining technical renewable potential across SPP
- Develop conventional resource sites and conceptual solar and wind sites as needed
- Rank and select sites
- Post site prioritization and selections for review
- Make any necessary adjustments and repost for approval

1.6: General Site Screening Criteria by Technology

The following screening criteria will be used to identify potential sites for further ranking and vetting by SPP staff and applicable stakeholders. GIS software will be used to determine suitable locations by generator technology. The GIS software will include locations of gas pipelines, restricted areas such as federal and state class I lands, air quality non-attainment regions, and other geographic information needed to develop sites.

Natural Gas Fired Combined Cycle Screening Criteria:

Required criteria:

- In close proximity to gas pipelines
- Outside State, Federal Class I lands and air quality non-attainment region

Optional criteria:

- In close proximity to major urban area and load centers with high load factors

- In close proximity to a railroad, navigable waterway, or alternative fuel supply
- In close proximity to a river or a lake
- In close proximity to transmission and gas pipeline intersections

Natural Gas Fired Simple Cycle Screening Criteria:

Required Criteria:

- In close proximity to gas pipelines
- Outside State, Federal Class I lands and air quality non-attainment region

Optional Criteria:

- In close proximity to major urban area and load centers
- In close proximity to a railroad, navigable waterway, or alternative fuel supply
- In close proximity to transmission and gas pipeline intersections

Base load Steam Coal or IGCC screening criteria:

Required Criteria:

- In close proximity to a railroad or navigable waterway
- In close proximity to a major river or lake
- Outside State, Federal Class I lands, air quality non-attainment region, and major urban areas

Optional Criteria:

- In close proximity to a mine
- In close proximity to a gas pipeline
- In close proximity to multiple railroad lines

Nuclear screening criteria:

Required Criteria:

- Use existing nuclear sites
- Use proposed nuclear sites
- In close proximity to a major river or lake
- Locate in geologically stable areas

Wind screening criteria:

Required Criteria:

- Outside airports, State, Federal Class I lands, and major urban areas
- Use required acres per MW
- Use geographic areas with higher than average/annual wind speeds
- Use remaining technical potential by pricing zone, state, sub-region, or region
- Use practical sizes per interconnection voltage

Optional Criteria:

- Use cleared land

- Use land higher in elevation relative to immediate surroundings
- Use local, state, and federal public policies
- Use other Federal Aviation Administration permitting criteria
- Use 230 kV and 345 kV buses for larger conceptual sites
- Use conceptual sites from NREL

Utility Scale Solar photovoltaic screening criteria:

Required Criteria:

- Outside State and Federal Class I lands
- Use required acres of level land per MW
- Use geographic areas with higher than average/annual insolation or irradiance
- Use remaining technical potential by pricing zone, state, sub-region, or region
- Use practical sizes per interconnection voltage

Optional Criteria:

- Use cleared land
- Use 230 kV and 345 kV buses for larger conceptual sites
- Use conceptual sites from NREL

Optional Screening Criteria:

- Use applicable local, state, and federal public policies
- Use other applicable land use constraints
- Use applicable environmental constraints

Although the primary types of resources added to the ITP assessments will be conventional gas-fired, wind, and solar, other types may be considered for future policy standards, technological advancements, or other drivers. If resources falling into categories outside of those discussed above are added through the ITP resource plan, coordination between staff and stakeholders will drive where these resources are sited.

1.7: Siting for External regions

The resource plan for each of the modeled regions external to SPP will be based on the corresponding company's resource plan in their most current regional planning study, as available and appropriate. If this data is not available or appropriate, as determined by stakeholders and SPP staff, the mix of conventional resource additions will be added to each external region as close as possible to those added through the SPP region's resource plan.

Publicly-known efforts to site future generation at particular locations would be the most reliable source for external siting information. For consistency across planning studies, locations utilized in

other regional planning processes will also be considered. If these sources do not result in sufficient siting information for resource plan generation, EHV buses near or at existing generation in the appropriate company's footprint will be used; it is assumed that transmission capacity in these areas are sufficient for adequate power transfer without in-depth transfer analysis. For siting of resources in these external regions, the following priority will be used:

- Publicly available siting data from company integrated resource plans (IRPs),
- Locations utilized in other external regional processes, and
- EHV buses near other generation.


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

Standard ITP Model Names

June 29, 2017

Standard ITP Model Names

Current Name – Recommended Name

- Base reliability model – Reliability Base
- SPP BA economic model – Economic market model SPP
- BA powerflow model – Reliability market model

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INTEGRATED TRANSMISSION PLANNING MANUAL

Published on ~~DATE~~July 12, 2017

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By ~~AUTHOR/DEPARTMENT~~SPP staff

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
10/13/2010	SPP Staff	Initial Draft approved by the MOPC.	
1/7/2011	SPP Staff	Incorporated TWG and ESWG edits to the ITPNT and ITP20 sections.	
7/13/2011	SPP Staff	Revised Draft approved by the MOPC.	
9/02/2014	SPP Staff	Revised by the ITP Manual Task Force	
12/15/2014	ESWG	Accepted Task Force Edits	
06/22/2017	SPP Staff	Implementation of TPITF recommendations	

CONTENTS

1 INTRODUCTION

1.1 PURPOSE

The SPP Open Access Transmission Tariff (OATT or SPP ~~t~~Tariff) Attachment O ~~Section III~~ requires Southwest Power Pool, Inc. (SPP) to conduct the Integrated Transmission Planning (ITP) Assessment~~review the transmission system for a ten-year planning horizon and identify cost-effective solutions over a 40-year time horizon~~ in accordance with this~~e~~ Integrated Transmission Planning Manual. This manual will outline the methodology, criteria, assumptions, and data necessary for the~~processes~~ for the ~~annual Integrated Transmission Plan (~~ITP assessment~~)~~.

The ITP assessment is a regional planning process built to leverage knowledge of the transmission system's reliability, public policy, ~~compliance,~~ operational, and economic needs, as well as compliance, generator~~ion~~ interconnection, and transmission service request impacts ~~in order~~ to develop a cost-effective transmission portfolio over a 10-year planning horizon. ~~Utilizing a~~ A common set of foundational modeling assumptions will be utilized as the starting point for all planning studies ~~within the planning cycle, the models for all reliability, public policy, compliance, operational, and economic studies will be developed to produce needs assessments for two-, five- and 10-year planning horizons~~. System needs resulting from generator~~ion~~ 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 ITP ~~process~~ assessment to facilitate continuity in the overall transmission expansion plan. This targeted approach is both forward-looking and proactive, designed to facilitate~~ing~~ a cost-effective and responsive transmission network ~~which~~ that adheres to the ITP principles (listed in History of the ITP Assessment~~History of the ITP section 1.B~~), while following the Federal Energy Regulatory Commission (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,~~ operational, and economic considerations in project or portfolio recommendations. The assessment of a project or group of projects' performance may include:

- Performance across multiple futures
- Ability to solve multiple need types
- Reliability impacts related to compliance with North American Electric Reliability Council (NERC) Standard TPL-001[2]
- 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~~period. The objective is to produce the most economical project planning over the longer-term horizon.

This manual includes standardized language detailing ITP ~~study~~ assessment items that were reviewed by the appropriate SPP stakeholder groups and approved by the Markets and Operations

[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.

[2] NERC TPL-001

Policy Committee (MOPC). This standardization will provide specific details ~~around~~ on each scope item and eliminate the need for repetitive reviews and approvals ~~in order~~ to help facilitate the performance of a planning cycle that produces an annual report. ~~SPP stakeholders will retain the ability to request a modification of standardized scope items by utilizing the SPP Revision Request (RR) process as discussed in the Revision Request Process section of this manual.~~ An ITP ~~study~~ assessment scope will be developed for each ITP assessment for items that will require SPP stakeholder review and approval with each new study. This process is described further in the Study Scope Document section of this manual.

1.2 REVISION REQUEST PROCESS

A request to make additions, deletions, revisions, or clarifications to this ITP ~~m~~Manual shall be made in accordance with the SPP revision request process.[3] ~~.~~

~~1.2~~1.3 OVERVIEW OF THE SPP ITP ~~PROCESS~~ASSESSMENT

The ITP ~~process~~ assessment is SPP's approach to planning transmission upgrades needed to maintain reliability, provide economic benefits, and achieve public policy goals for the SPP region in ~~both~~ the near- and long-term horizons. The ITP ~~process~~ assessment enables SPP ~~staff~~ and stakeholders to facilitate the development of a reliable and flexible transmission grid that provides regional customers improved access to the ~~SPP~~ region's diverse resources.

The ITP ~~process~~ assessment assesses transmission needs over a 10-year horizon and is intended to produce an annual report. It is designed to create synergies by integrating SPP transmission planning activities that incorporate reliability, economic, policy, and operational~~, and compliance~~ components in the overall assessment of the transmission grid. The ITP ~~process~~ assessment works in concert with SPP's existing sub-regional planning stakeholder process~~,~~ and parallels the NERC transmission planning reliability standards compliance process.

~~1.2.1 HISTORY OF THE ITP ASSESSMENT~~

~~In January 2009, the SPP Board of Directors (Board) created the Synergistic Planning Project Team (SPPT) to address gaps and conflicts in SPP's transmission planning processes; to develop a holistic, proactive approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities.~~

~~The SPPT recommended that the organization adopt a new set of planning principles, develop and implement an ITP processassessment, develop a plan to monitor the construction of projects approved through the ITP process assessment, and identify priority projects that continue to appear in system reviews to relieve congestion on existing constraints, and connect SPP's eastern and western regions. The SPPT recommended that the Regional State Committee (RSC) establish a "highway/byway" cost allocation methodology for approved projects.~~[4]

1. ~~The SPPT created an the following principles ITP assessmentto drive development of the ITP process:~~

[3] SPP Revision Requests
[4] ~~The Highway/Byway methodology was approved by FERC on June 17, 2010.~~

- ~~Focus on regional needs while also considering local needs; long-range plans (both ITP 20-year assessment and ITP 10-year assessment) are to be updated every three years, while ITP Near-term assessment (ITPNT) plans are to be updated annually.~~
- ~~Plan the backbone transmission system to serve SPP load with SPP resources in a cost-effective manner. The transmission backbone will:~~
  - ~~Enhance interconnections between SPP's western and eastern regions,~~
  - ~~Strengthen existing ties to the Eastern Interconnection.~~
  - ~~Provide options for planning and coordination to the Western Electricity Coordinating Council (WECC) and the Electric Reliability Council of Texas (ERCOT) grids in the future.~~
- ~~Incorporate 20-year physical modeling and 40-year financial analysis timeframes.~~
- ~~Better position SPP to proactively prepare for and respond to national priorities while providing flexibility to adjust expansion plans.~~

~~SPP began performing its planning duties in accordance with the ITP process~~ assessment ~~in January of 2010.~~

Commented [KH1]: Move to Appendix

~~1.2.12~~1.3.1 ORGANIZATIONAL GROUP SUPPORT

The Economic Studies Working Group (ESWG) identifies and maintains the economic data, data sources, models, economic planning methodology and processes, and benefit metrics to be used in the evaluation of economic expansion needs in the SPP region.

The Transmission Working Group (TWG) oversees and maintains the study processes for reliability and compliance to be used in the evaluation of reliability expansion needs in the SPP region.

The Operating Reliability Working Group (ORWG) identifies and maintains operational data, data sources, and models to be used in the evaluation of persistent operational expansion needs in the SPP region.

The ORWG, TWG, and ESWG are responsible for ~~the process of~~ identifying needs associated with persistent operational issues.

The ITP recommended plan will be reviewed and may be endorsed by ESWG, TWG and MOPC. ~~Those recommendations approved by the Board will allow SPP staff to issue notifications to construct (NTCs), notifications to construct with conditions (NTC-Cs) or requests for proposal (RFPs) (for approved competitive projects) letters for projects needed within the financial commitment horizon.~~

~~1.3~~1.4 WORKING GROUP OWNERSHIP

ECONOMIC STUDIES WORKING GROUP ~~(ESWG)~~

~~T~~Generally, the ESWG will be responsible for review of ~~the~~ data and results for the following items:

- Scope
- Scenarios developments~~s~~
- Load forecasts
- Existing and planned g~~G~~eneration ~~review~~

- Renewable policy requirements~~view~~
- Resource plan ~~review~~
- SPP balancing authority (BA) economic model
- Economic analysis
- Recommended Plan
- Benefit metrics
- Sensitivities
- Assessment ~~R~~report

TRANSMISSION WORKING GROUP ~~(TWG)~~

~~T~~Generally, the TWG will be responsible for review of the data and results for the following items:

- Scope
- Transmission topology
- Load forecasts
- Existing and planned g~~G~~eneration ~~review~~
- Base reliability models
- SPP BA powerflow models
- Constraint assessment
- Reliability analysis
- Recommended plan
- Assessment ~~R~~report

MODEL DEVELOPMENT WORKING GROUP ~~(MDWG)~~

Generally, ~~T~~the MDWG will be responsible for review of the data for the following item:

- Load forecasts
- Existing and planned g~~G~~eneration ~~review~~
- Transmission topology

SEAMS STEERING COMMITTEE ~~(SSC)~~

The Seams Steering Committee (SSC) will be responsible for the review of the following:

- Seams impacts

STRATEGIC PLANNING COMMITTEE ~~(SPC)~~

The Strategic Planning Committee (SPC) will provide input for the following items:

- Scenarios development
- Policy decisions

MARKETS AND OPERATIONS POLICY COMMITTEE ~~(MOPC)~~

~~The~~ MOPC will make a recommendation to the SPP Board regarding approval decisions of the following items:

- ~~ITP~~ Assessment r~~R~~eport

REGIONAL STATE COMMITTEE ~~(RSC)~~

The RSC will review the following items:

- ~~ITP~~ Assessment r~~R~~eport

SPP BOARD OF DIRECTORS ~~(BOARD)~~

The Board will make approval decisions for the following items:

- ~~ITP~~ A~~A~~ssessment r~~R~~eport
- ~~ITP~~ R~~R~~ecommended p~~P~~lan

~~1.4~~1.5 THE TRANSMISSION PLANNING IMPROVEMENT TASK FORCE

In February 2015, the Transmission Planning Improvement Task Force (TPITF) was assembled by the SPC and the MOPC and given the responsibility for developing recommendations to improve the regional planning processes. Their objective was to make the SPP transmission planning process more responsive to the effects of the continued growth of SPP's transmission system, changes in the SPP markets, challenges and opportunities presented by changing federal and state energy and environmental regulations and increasing NERC compliance requirements. The TPITF was tasked with reviewing, evaluating and proposing recommendations on the following:

1. The methodologies and modeling practices used in the generator~~ion~~ interconnection studies, aggregate transmission service studies, integrated transmission planning (near-term, 10-year, and 20-year assessments), SPP assessments for compliance with NERC TPL standards and the MDWG model development process to ensure effectiveness, consistency and to determine if gaps exist between the various processes.
2. The utilization of data, including data collected by operations, which will benchmark the real-time and planning horizon assessments to ensure consistency in the planning process.
3. The appropriateness of the planning cycle and assessments, including the effectiveness of using production cost modeling in more assessments; development, use and weighting of futures, scenarios and sensitivities; the metrics used to evaluate proposed projects, in particular those that evaluate the impact on rate payers; and planning the transmission system beyond the traditional planning criteria of first contingency ("N-1") in accordance with the approved NERC Standard TPL-001.

The TPITF recommendation whitepaper[5], was intended to represent a consolidated, coordinated approach in planning, managing, and maintaining the SPP transmission system, with a particular emphasis on increasing the availability of transmission service to SPP's customers without unduly compromising system reliability. The recommendations in the TPITF recommendation whitepaper were intended to enable the cost-effective use of capital-intensive generating resources for the benefit of all end-use customers in the SPP footprint and to further develop and enhance policies, tools and practices to optimize the use of the transmission system. The TPITF developed five recommendations to accomplish this scope of work that are discussed in detail throughout this

[5] ~~SPP Planning Process Improvement Recommendations~~

manual:

1. Replace the current ITP schedules with an annual transmission expansion plan.
2. Create a standardized scope.[6]
3. Establish a common planning model for use across the various SPP planning processes.
4. Utilize a holistic planning process.
5. Create SPP staff/stakeholder accountability process for the timely exchanges of data, reviews and approvals.

~~1.5~~1.6 ~~UPDATED~~ ITP ~~PROCESS~~ASSESSMENT SCHEDULE

~~In July 2016, the the SPP MOPC, Board and the SPC approved the recommendation of the TPITF to replace the three-year ITP study cycle with a planning cycle producing an annual report. The recommendation included removal of the ITP20 assessment from cyclical the planning process and combining of the ITPNT and ITP10 assessments into a single study with a 10-year outlook.~~ The planning cycle, as illustrated in Figure 1, will consist of scope development and model development for approximately 12 months and a planning assessment period of approximately 12 months. The scope and model development for the succeeding cycle will begin concurrently with the planning assessment period of the preceding study resulting in a 12-month overlap. This planning cycle will result in an annual assessment report with a set of recommended projects.

The assessment will also ~~incorporate~~ satisfy the NERC Standard TPL-001 short-circuit and portions of the NERC Standard TPL-001 steady-state assessment requirements~~s~~. The ITP ~~study~~ assessment will assess years 2, 5, and 10 for reliability, public policy, ~~compliance,~~ operational, and economic needs.

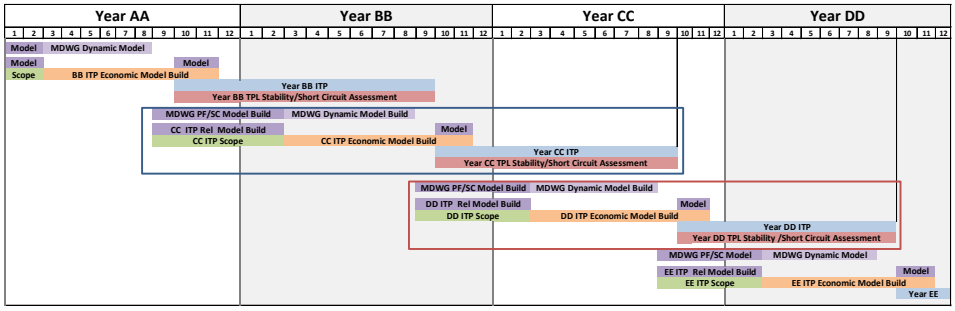


Figure 1: ITP Cycle

~~The planning cycle, as illustrated in Figure 1, will consist of scope development and model building development for approximately 12 months and a planning assessment period of approximately 12 months. The scope and model development and model build for the succeeding cycle will begin concurrently with the planning assessment period of the preceding study resulting in a 12-month~~

[6] ~~The standardized scope is referred to as the ITP manual in this document. Previous versions of the ITP manual can be found on the SPP website.~~

~~overlap that will produce a report annually at the completion of each cycle. This planning cycle will result in an annual assessment report with a set of recommended projects.~~

1.7 STUDY SCOPE DOCUMENT

~~In order t~~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 SPP 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.

1.8 ~~COMPLIANCE WITH C~~CONSIDERATION OF NERC STANDARD TPL-001

The analyses performed for the holistic planning assessment described in this manual ~~are intended to~~ allow SPP to meet the requirements of the SPP ~~t~~Tariff, as well as a portion of the NERC standards for transmission planning requirements detailed in NERC Standard TPL-001. This allows for a consistent approach in the planning processes while ~~authorizing~~ allowing SPP to issue NTCs to transmission owners (TOs) to construct upgrades needed to meet certain NERC Standard TPL-001 Table 1 requirements.

The Reliability Needs Assessment section detailed in this manual will describe the assessment of transmission system planning events in NERC Standard TPL-001 Table 1 for which non-consequential load loss or the interruption of firm transmission service is not allowed. A common powerflow analysis for the ITP assessment and NERC Standard TPL-001 will be performed for these planning events. Additionally, the short-circuit analysis required by NERC Standard TPL-001 will be performed and a subset of those needs will be considered as ITP needs.

While these analyses will be common to both the ITP assessment and the requirements of the NERC Standard TPL-001 ~~standard~~, SPP ~~staff~~ will continue to compile and issue a separate annual report (SPP Compliance~~TPL-001 Planning~~ Assessment) to fully document SPP's compliance with all NERC Standard TPL-001 ~~standard~~ requirements.

2 MODEL DEVELOPMENT

Table 1 lists the model sets for the ITP ~~planning~~ assessment cycle. ~~Once~~ After the model set~~s~~ ~~is~~ are finalized, no topology changes will be accepted to ~~correct~~ update the model. Any identified model changes will be required to be submitted during the detailed project proposal (DPP) window as detailed in the Model Adjustments section.

Description	Year 2	Year 5	Year 10	Total
Base Reliability~~1~~ ~~(TPL² Base Case)~~	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	9
SPP BA (Economic)	One Future (1)	Each Future (1-3)	Each Future (1-3)	3-7
SPP BA Powerflow (Reliability) ~~(TPL² Sensitivity Case)~~	One Future's Peak and Off-Peak (2)	Each Futures' Peak and Off-Peak (2-6)	Each Futures' Peak and Off-Peak (2-6)	6-14

Table 1: ITP Model Sets

2.1 BASE RELIABILITY MODEL OVERVIEW

The base reliability model set will be the base model set for all of SPP's planning processes including transmission service, generator interconnection, and compliance studies. Each of the base reliability models will be an indicative representation of how entities within SPP responsible for serving network load would do so utilizing network resources only. These models will consist of non-coincident peak load forecasts, assumed long-term firm transmission service usage levels, and expected conventional and renewable resource output levels. ~~The base reliability model set will be the base model set for all of SPP's planning processes including transmission service, generation interconnection, and compliance studies.~~

~~The ITP process will be used to satisfy the planning requirements found in Attachment O of the SPP Tariff, as well as some NERC compliance requirements within NERC Standard TPL-001 (TPL) using a common planning model scenario, or base reliability model. Nine total powerflow models will be built usingdeveloped following the base reliability model methodology of the base reliability model. Table 2 describes the years and seasons that will be developed by SPP for this model set.~~

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

Table 2: Years and Seasons of Base Reliability Model Set

This model set will also be utilized as the base 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 develop the models will be provided by SPP members TOs and stakeholders with appropriate review opportunities by SPP staff and stakeholders, prior to receiving final approval. These inputs, described in the following sections, include but are not limited to:

- Generation resources
- Load forecasts
- Definition of the SPP footprint
- Topology
- Modeling of firm transmission service
- DC tie modeling
- DC line modeling
- Phase-shifting transformers (PSTs)
- NTC re-evaluation requests

All data requests and review opportunities for the base reliability model set will be administered through the MDWG and TWG, and the TWG will approve the base reliability models.

Additionally, a short-circuit model will be built developed for use ina the short-circuit assessment to meet short-circuit analysis required in thein consideration of NERC Standard TPL-001 standard. This short-circuit model will be built developed under the guidance of the MDWG.

2.1.1 GENERATION RESOURCES

Generation resources[7] shall be included in the base reliability model if any of the following requirements are met:

1. The resource is existing and in service.,
2. The resource has an effective Generator FERC filed iInterconnection aAgreement (GIA), not on suspension, and has approved long-term firm transmission service with an executed effective transmission service agreement, or.
3. The resource is approved by the TWG as meeting the requirements detailed in the Waiver Requests section of this manual, or.
4. The resource has been identified by SPP staff as necessary[8] in order to solve a model and is approved for inclusion by the TWG,[9] with considerations such as:
    a. Resources that are in the generatorion interconnection queue for study.

[7] Associated transmission upgrades will be modeled in accordance with the SPP tariff

[8] Reactive resources or previously approved transmission upgrades will also be considered as potential solutions.

[9] Resources added for this criteria will not be included in the SPP BA Economic model and SPP BA Powerflow unless they are also identified in the resource planning process

b. Resources that have an signed interconnection agreement (IA)effective GIA
c. Resources have been included in an approved SPP-developed resource plan.

Generation resources will be available for dispatch in the base reliability model if either of the following criteria are met:

1. The resource has approved long-term transmission service with an executed effective transmission service agreement, or
2. The resource has been identified by SPP staff has identified the resource as necessary in order to solve a model.

If a generation resource is utilized solely for reactive support, it will be dispatched to its P_{Min} value in the appropriate model(s). TWG approval will include the specific models for which the generation resource, reactive resource, or transmission upgrade will be included.

Generation resources may be modeled, but are not available for dispatch, if:

1. The resource does not have approved long-term firm transmission service[10]., or
2. The resource is mothballed or planned for retirement.

Generation resources that have been mothballed or are planned for retirement will must be submitted to SPP staff through SPP's modeling database tool and the SPP Request Management System (RMS) for the base reliability model. Upon receiving this information, these resources will remain in the models until such time they are officially decommissioned. Until this decommission occurs, the resources will be given a P_{Min}, P_{Max}, Q_{Min}, and Q_{Max} value of zero within the models to ensure that the units are not dispatched.

2.1.1.1 Waiver Requests

Certain generation resources and associated transmission service requests that have not fully completed the processes defined in Attachment V and Z1 of the SPP t Tariff, but have a high probability of going into service or obtaining an executed effective transmission service agreement, can be included in the base reliability model. Generation resources that meet all of the following requirements will be included:

1. A formal request has been sent to SPP requesting the generation resource be included in the base reliability model.,
2. The generation resource has an effective FERC-filed interim interconnection agreementGIA.,
3. The generation resource has entered the aggregate transmission service study or equivalent transmission owner transmission service study publicly posted on OASIS and has a completed facility study that is awaiting for final results without unmitigated third--party impacts.,
4. The generation resource has acquired air and environmental permits where applicable.
5. The generation resource has started construction with major equipment funding and procurement contracts awarded.

[10] Resources meeting this criteria will not be considered for dispatch in the base reliability model, however, they will be included for consideration in the SPP BA models (economic and powerflow).

If a generation resource does not meet all of the above requirements, a formal request for resource inclusion in the base reliability model can be submitted to the TWG for approval. The TWG will take the following information into account in deciding whether to approve the waiver:

1. A formal request has been sent to SPP requesting the generation resource be included in the base reliability model, including any additional information deemed relevant by the requesting entity. The request should identify which transmission upgrades will be deferred, if applicable.
2. The generation resource has a mitigation plan for the deferred transmission upgrades until it makes a financial commitment to complete the required upgrades.
3. A Definitive Interconnection System Impact Study (DISIS) Aagreement (DISIS) for the generation resource has been executed, an interim GIA has been requested, and a final GIA will be filed with FERCentered into when applicable.
4. An RFP for the generation resource has been awarded, if applicable.

2.1.2 FIRM TRANSMISSION SERVICE

SPP long-term pPoint-to-pPoint and Nnetwork long-term firmIntegration transmission service commitments are generally modeled at expected usage of firm transmission service reservations in each year and season, as supplied by SPP stakeholders engaged induring the SPP modeling process. Commitments with external entities not engaged during the SPP modeling process are coordinated with those entities through the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG).

The modeling of long-term firm transmission service in the base reliability models will result in a change in generation dispatch for the defined source and sink of the service and will vary by season, year and generation type.[11] All DC tie set points will be modeled with expected usage submitted by membersstakeholders, not exceeding firm transmission service for the season. Resources related to a transmission service reservation with a single plant as the source will be dispatched to meet the modeled usage. Conventional resources related to transmission service reservations with a fleet of resources as the source will be dispatched based on economic merit order within each resource fleet, as needed to serve the service commitments and internal load. The fleet of conventional resources will be dispatched after renewable resources. Renewable resources will be dispatched based upon the following seasonal methodologies:[12]:

- Light load: Wind output will be modeled at 100 percent% of firm transmission service in the light load base reliability model.
- Summer peak: Renewable resource output with firm transmission service will be modeled in the summer--peak base reliability model at each facility's latest five-year average (or replacement data if unavailable) for the SPP coincident[13] summer peak, not to exceed each facility's firm service amount.
- Winter peak: Renewable resource output with firm transmission service will be modeled in the winter--peak base reliability model at each facility's latest five-year average (or

[11] Resources may be added to a source or sink definition if the requirements of the Generation Resources section are met.
[12] The renewable dispatch methodology may necessitate a change to the modeled expected usage of firm transmission service.
[13] SPP coincident peak equals the highest demand including transmission losses for energy measured over a one clock hour period during the defined season.

replacement data if unavailable) for the SPP coincident winter peak, not to exceed each facility's firm service amount.

Replacement data may be necessary to determine the dispatch amount for each renewable resource~~s~~ type in the summer-peak, winter-peak, and light-load seasons if the resources have less than five years of data available. SPP ~~staff~~ will calculate the replacement data for use in the methodology for the summer and winter peak.

To calculate the replacement data, SPP ~~staff~~ will determine for each renewable type the amount of renewables being dispatched in each SPP coincident peak hour located within each state, then divide by the total amount of firm transmission service sold on those renewable resources. This will ~~give~~ provide a percentage of MW within each state dispatched during the SPP coincident peak hour. This calculation will be done for the five previous years. SPP ~~staff~~ will average the data together to develop a flat percentage value for each state. These state average values for each renewable type will be the replacement value for each renewable resource requiring replacement data located within that state to give each renewable resource five years of data.

2.1.3 LOAD FORECASTS

The ITP ~~process~~ assessment will require load forecasts for SPP ~~members and non-members~~TOs and stakeholders 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~~SPP using the process described in the Model Development Procedure Manual[14] ~~model building process~~. The load will represent each individual load-serving entity's peak conditions without losses per season (*i.e.*, non-coincident conditions for the SPP region).

2.1.4 TOPOLOGY

The topology used to account for the SPP transmission system, excluding future generation resources and associated interconnection facilities, will be the existing transmission system and any upgrades or facilities that are included in the SPP Transmission Expansion Plan (STEP) and ~~have received an NTC/NTC-C or~~ have been approved for construction ~~by SPP~~.[15] In-service dates of ~~Board-approved~~ upgrades with NTC/NTC-C should be consistent with the latest information supplied by the ~~TO~~ transmission owner in the p~~P~~roject ~~T~~tracking process. Upgrades that have met the requirements for NTC withdrawal or reevaluation ~~in accordance with SPP Business Practices~~ will be excluded from the base reliability model as specified in SPP business practices.

The base reliability models will be ~~built~~ developed to reflect the expected state of the transmission system over the long-term horizon. The model development process accounts for long-term transmission line outages as forecasted by the data submitting entity per the applicable NERC MOD standards. Temporary facilities shall not be modeled and transmission lines operated in real-time as normally ~~-~~open shall be modeled as normally ~~-~~open.

For topology updates outside the SPP footprint, the Eastern Interconnection model areas will be obtained from the latest ERAG MMWG model set. SPP will coordinate with the appropriate external entities and request first-tier planned upgrades that should be included in the models.

[14] MDWG Model Development Procedure Manual

15 This includes upgrades identified through the generator interconnection process and those approved by Southwestern Power Administration.

2.1.4.1 Phase-Shifting Transformers

PSTs will be model~~ed~~ed~~ing~~ in accordance with the guidelines documented in the MDWG Manual[16].

2.1.5 EXTERNAL TRANSACTIONS

Transaction~~s~~ data between entities external to the SPP footprint, not including those with transmission service with SPP, will be obtained directly from the external entity, if available, or from the latest ERAG MMWG models that most closely align with the corresponding study year models.

2.2 SPP BA ECONOMIC MODEL OVERVIEW

Each SPP BA economic model simulation is an hourly security-~~-~~constrained unit commitment and economic dispatch utilizing a DC representation of the transmission system.

The assumptions for each of the economic models are detailed later in this section.

2.2.1 MODEL ASSUMPTIONS AND DATA

2.2.1.1 Future Development

Due to the uncertainties involved in forecasting future system conditions, a number of diverse futures will be considered that take different assumptions into account. Consideration of multiple futures allows 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 from the SPC and the TWG and will be subject to the approval of MOPC.

Economic models will be developed for three study years (years 2, 5, and 10). A single future will be developed for year 2, due to the limited uncertainty in policy or other factors impacting the system that could occur 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, and up to two additional futures designed to assimilate expected or plausible future scenarios. Details ~~around~~ about the reference case and any other 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.

During the development of the futures, SPP ~~staff~~ will solicit stakeholders for potential public policy drivers to be considered in the study through a survey within the SPP annual data request. ~~The time, place, and method~~ Timing for the submission of public policy drivers that SPP stakeholders request to be considered shall be included in the study schedule. Any drivers requested to be considered by SPP stakeholders that are excluded from the study, as well as an explanation for the exclusion, shall be detailed in the ITP ~~study~~ assessment report.

2.2.1.2 Load and Energy Forecasts

The ITP ~~process~~ assessment will require load forecasts for areas within and outside the SPP footprint for each of the study years. The load will represent each individual load-serving entity's peak conditions without losses per season (*i.e.*, non-coincident peak conditions for the SPP region).

[16] MDWG Model Development Procedure Manual

Resource obligations will be determined for the footprint taking into consideration non-scalable and scalable loads.

For the economic model ~~build~~ development process, SPP ~~staff~~ will obtain load data to utilize in the ITP ~~process~~ assessment by the following unless directed otherwise by the ESWG:

- Peak load: The source shall be the no-loss aggregated bus load totals (MW) based on the current base reliability models.
- Hourly load shape: The primary source shall be third-party vendor data. If the primary source is not available or is not appropriate, SPP ~~staff~~ will create a synthetic load shape based ~~off of~~on historical data points and FERC Form 714 information.
- Monthly peak and energy percentages: The primary source shall be third-party vendor data. If the primary source is not available or is not appropriate, SPP ~~staff~~ will calculate the monthly peak and energy percentages by using hourly load shape data.
- Load factor: ~~The~~ As a primary source, ~~shall be~~ annual load factors shall be provided by~~for~~ SPP stakeholders ~~to provide annual load factors~~. If the primary source is not available or is not appropriate, SPP ~~staff~~ will calculate load factors by utilizing hourly load shapes.
- Transmission loss factor: ~~The~~ As a primary source ~~shall be~~ annual loss factors shall be ~~for~~provided by SPP stakeholders ~~to provide annual loss factors~~. If the primary source is not available or is not appropriate, SPP ~~staff~~ will utilize previous ITP study values.
- Demand mapping: The primary source shall be the economic load ownership legend[17] reviewed as part of the SPP annual data request. If the primary source is not available or is not appropriate, SPP stakeholders will provide load bus and ID mappings to demand groups.

External region load forecasts will be taken from the base reliability model set~~,~~ and each region will be allowed to review load forecast data prior to ~~using~~ use in the ITP ~~processes~~assessment. If readily available and ~~SPP staff and stakeholders find it~~ appropriate, load forecasts from the most current neighboring entity's study will be used for their region in the ITP assessment in place of the base reliability model data. The use of their load forecast will be future specific. If there is not a future comparable to the ITP future, as determined by SPP ~~staff~~ and the ESWG, the load forecast would be determined utilizing base reliability model data. The data sources used will be documented in the study scope.

2.2.1.3 Renewable Policy Review

After the forecasted load is finalized, renewable policy standards (RPS) will be assessed for utilities within the SPP footprint. The percentages in Table 3 will be used to calculate the mandate or goal for each utility residing in the listed states with respect to the load submitted as part of the SPP annual data request. For those utilities that span multiple states, the approved powerflow models and geographical information system (GIS) data will be used to calculate each utility's load obligation in the corresponding state for purposes of calculating mandates and goals.

The values in Table 3 consider forward-looking legislation set by the states that should be met in each of the study years. A generation type of "both" indicates the mandate or goal can be met by either wind or solar generation in the study. Both capacity- and energy-based mandates and goals

[17] Table within the SPP annual data request that maps loads according to their attributes to groups of demands for the economic model

will be assessed for fulfillment during development of the resource plan. Those that are energy-based also will ~~also~~ be assessed during the policy needs assessment. States within the SPP footprint that are not included in Table 3 shall be presumed to have no RPS requirement for the purposes of this renewable policy review.

State	RPS Type	Generation Type	Capacity- or Energy- Based	Year 2 %	Year 5 %	Year 10 %
Kansas	Goal	Both	Capacity	20	20	20
Minnesota	Mandate	Both	Energy	20	20	25
Missouri	Mandate	Both	Energy	15	15	15
Montana	Mandate	Both	Energy	15	15	15
North Dakota	Goal	Both	Energy	10	10	10
New Mexico	Mandate	Wind	Energy	15	15	15
New Mexico	Mandate	Solar	Energy	4	4	4
South Dakota	Goal	Both	Energy	10	10	10
Texas	Mandate	Both	Capacity	5	5	5

Table 2: ITP RPS by State

Renewable energy credits ~~(RECs)~~ will be ~~appropriately~~ accommodated appropriately as provided to SPP ~~staff~~.

If any significant changes to renewable mandates or goals occur during an ITP assessment, SPP stakeholders can bring them to the ESWG for review and potential approval for use in the ITP assessment. If exemptions to the mandates or goals are allowed (e.g. the applicable technology is cost prohibitive or municipals are exempt), those exemptions will be considered as SPP ~~staff~~ is notified during the renewable policy review.

Any resulting deviations from the standard values in Table 3 will be noted in the study report.

2.2.1.4 Generation Resource Inclusion

Generation resources included in the base reliability model will be incorporated into the economic model, as appropriate.[18] Resources identified by SPP ~~staff~~ as necessary ~~in order~~ to ~~develop~~ solve the base reliability model shall not be included in the economic and powerflow models, unless the resources meet the requirements of adding generation described ~~below~~in this section.

[18] Generally, smaller resources that are not included in the economic data supplied by the vendor but are modeled in the powerflow are not included in the economic model for consideration in the production cost simulation. Examples are units reported publically as behind the meter or small municipal generation.

Incremental to the resources included in the base reliability models, a generator~~ion~~ interconnection resource and its associated network upgrades will be included in the economic models if they meet all of the following requirements:

1. A formal request has been sent to SPP[19] requesting the generation capacity be included.
2. The generating resource has an effective ~~FERC-filed~~ GIA that is not on suspension or ~~FERC-filed~~ an effective interim GIA~~, and~~
3. The generating resource will have a firm contract for delivery through ownership and operation of the resource or procurement of a purchase power agreement (PPA) from the generation owner.

If a generating resource does not meet all the above requirements, a request for generation capacity to be included in the economic models can be made to ESWG and TWG on a case-by-case basis. ESWG and TWG will, at a minimum, consider the following points:

1. A DISIS agreement for the generating resource has been executed, an interim GIA has been requested, and a ~~final~~ GIA will be ~~FERC filed~~entered into, when applicable.
2. An RFP for the generating resource has been awarded, if applicable.

All other resource expansion needs will be determined through the SPP resource expansion planning process as detailed in the Resource Expansion Plan section.

2.2.1.5 Generation Resources

Third-party v~~V~~endor data will be used as the starting point for generation parameters needed for the economic model set. Data related to the physical characteristics of generators will be reviewed and updated as needed by the SPP stakeholders to provide company-specific values through the SPP annual data request.

The ~~vendor~~ third-party vendor data to be utilized as a starting point may include:

- Generator name
- Category type
- Conventional variable operation & maintenance (VOM)
- Conventional fixed operation & maintenance (FOM)
- Heat rate
- Heat rate profile
- Physical state location
- Annual maintenance hours
- Forced outage rate
- Effluents (percentage removed)
- Emission rates
- Fuel forecast
- Hydro energy limits
- Seasonal max capacity by year

[19] Submitted through SPP RMS

- Retirement date
- Commission date
- Must-run designation

2.2.1.6 Topology

The topology used in the economic models to account for the transmission system of SPP and external entities will follow the same guidelines detailed in the Base Reliability Model Overview section with ~~a few~~the following exceptions:

- The topology utilized for each study year's annual simulation will be based on the summer-peak base reliability model developed for that year.
- Long-term transmission outages as forecasted by the data submitting entity will not be included.

2.2.1.6.1 DC Lines

DC lines are included in the economic model through an import of the base reliability powerflow data. The range of allowable hourly operation will be based on:

- Operational practice (current or future expected), and
- Expected flows from the SPP powerflow models.

2.2.1.6.2 Phase-Shifting Transformers

Modeling parameters for PSTs will be determined leveraging data from:

- Historical and/or current operating practices, and
- Powerflow modeling.

The specific modeling of the PSTs will be detailed in the study scope.

2.2.1.7 Fuel Prices

Fuel price forecasts for the reference case future, including natural gas, oil, uranium, coal, and associated 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.

2.2.1.8 Emission Prices

Emission price forecasts for the reference case future, including 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.

2.2.1.9 Hurdle Rates

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

2.2.1.10 Renewable Pricing

The economic modeling of wind and solar resources include two primary parameters that impact pricing: curtailment price and VOM.

Wind and solar resources include an hourly profile. The curtailment price for wind and solar is the price at which the resource will curtail. If the LMP at the generation bus is greater than or equal to the curtailment price, the unit will generate energy in accordance with the hourly profile. If the locational marginal price (LMP) at the generation bus is less than the curtailment price, the unit generation will be curtailed. As a result, the curtailment prices impact the dispatch of wind and solar units in the economic models but do not impact the operating cost of the units.

In order tTo model a curtailment price for wind units that will reflect market operation, including projected production tax credit (PTC) impacts, the following criteria will be used for wind curtailment price modeling:

- Wind units will have $0/MWh curtailment price if any of the following are true[20]:
  - The unit is placed in service over 10 years prior to the study year.
  - Construction on the unit has not started prior to January 1, 2020.
  - An entity associated with the unit has provided feedback that the investment tax credit (ITC), rather than PTC, is applicable.
- Otherwise, wind units will have a negative $35/MWh curtailment price to reflect the "grossed-up" value of a PTC[21].

In order tTo model a curtailment price for solar units that will reflect market operation, the curtailment price will be set at $0/MWh.

The VOM for wind and solar resources defines the unit operating cost per MWh of energy generated. This operating cost is included in production cost calculations. The VOM parameter does not impact dispatch, curtailment, or LMPs in the economic model simulations.

In order tTo reflect power purchase agreement (PPA) pricing as part of the VOM, the following criteria will be used for VOM modeling:

- The SPP annual data request process for generation shall include reporting of the wind and solar units which have fixed-contract prices, such as PPAs. SPP staff will request appropriate documentation of units reported.; Iif documentation is provided, the VOM of the unit shall be based on approximate wind and solar fixed-contract pricing, derived from publicly available data. A weighted average of the most recent five- to 10--year period shall be used.
- For all wind and solar units in which appropriate documentation is not provided to SPP staff, the VOM of the unit shall be $8/MWh to reflect the low operating cost of renewable resources.
- For wind or solar units identified through the resource expansion plan, the VOM of the new unit shall be equal to the VOM of the majority of existing wind or solar units in the model.

[20] Reflecting that the PTC is not a factor in its operation
[21] Reflecting income tax compensation

- Example: If 80 percent of existing wind units have the fixed-contract price for VOM, new wind units would use the fixed-contract price for VOM.

2.2.1.11 Must Run Units

Must-run units in the ITP ~~studies~~ assessment are dispatched during all available hours to ~~at least~~ their minimum capacity states, regardless of economics. Must-run statuses will be removed from all units at the start of each study. In the development of the ITP study scope, the ESWG will determine if must-run units will be allowed and the criteria needed for such designation. Individual generating units meeting must-run criteria will be submitted by SPP ~~staff~~ or stakeholders during the generation review and subject to approval by the ESWG.

~~***2.2.2.0 SCUC & SCED Analysis***~~

~~An economic assessment will be performed to analyze congested facilities in 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. During the SCUC, 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). The SCUC does not explicitly consider 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 simulation will solve using nodal locational marginal prices (LMPs), 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.~~

~~2.2.7~~2.2.2 RESOURCE PLAN

~~*2.2.7.1*~~*2.2.2.1 Resource Expansion Plan*

After forecasted load and existing and planned generation have been defined through the SPP annual data request ~~schedule~~, analysis will be conducted to determine new (conventional and renewable) resource additions required in years 5 and 10~~,~~ for each future in the economic and SPP BA powerflow model. Resource additions are included ~~in order~~ to develop realistic future ~~-~~year models~~,~~ by accounting for reserve margin requirements, historical trends, economics, etc. The resource-planning phase will identify new units and the associated parameters for these new units, but will not include any siting considerations, which will be addressed in the Resource Siting Plan section. The year 2 models will be assessed to evaluate whether the reserve margin requirements are being met at the SPP BA level.

~~2.2.7.1.1~~2.2.2.1.1 Renewable Resource Expansion Plan

SPP ~~staff~~ shall develop a resource plan to meet renewable expectations for the region. This will include capacity as required through the renewable policy review, as well as capacity identified through criteria developed by SPP ~~staff~~ and stakeholders. Consideration will be given to the futures being studied and factors such as government regulations, historical trends, natural gas prices, installation trends, integrated resource plan projections, and SPP stakeholder feedback.

Renewable additions will be computed using criteria that can be applied uniformly across pricing zones.[22] For example, each pricing zone ~~shall~~ should have renewable capacity of at least a certain percentage of their annual peak ~~-~~load responsibility. Renewable resources other than wind and solar (such as biomass) shall only be added to the model as defined in the Generation Resource Inclusion and Generation Resources sections.

External regions and areas that are economically dispatched in the model may include renewable additions beyond the units planned at the time of study. An appropriate resource plan from the most current external entity's study will be used for their region in the ITP assessment, if readily available and ~~SPP staff and stakeholders find it~~ appropriate. These resource plans are future-specific.

If there is not an appropriate or available resource plan of a future comparable to a given ITP future, as determined by SPP ~~staff~~ and the ESWG, these renewable additions shall be determined by SPP ~~staff~~ and the ESWG in each study. Consideration will be given to the futures being studied and factors such as government regulations, historical trends, natural gas prices, installation trends (nation ~~-~~wide and location-specific), integrated resource projections, and feedback from external entities.

~~2.2.7.1.2~~2.2.2.1.2 Conventional Resource Expansion Plan

Each pricing zone shall be assessed for resource adequacy by accounting for load projections, existing generation, new wind and solar additions, capacity accreditation for all renewable units, fleet PPAs, and DC tie accreditations. Each pricing zone's resource shortfall shall be computed based on the SPP reserve margin requirement in effect at the commencement of the resource planning milestone ~~time~~ of the study.

The conventional resource expansion plan process begins with the identification of a publicly ~~-~~available source for generator prototype parameters, which shall be documented in the study scope.

Resource expansion software will be used in all futures to identify the optimal~~um~~ mix of new conventional resource additions needed for the SPP region.[23] ~~.~~ The magnitude of resource additions will be based on resource shortfalls. Ownership of ~~C~~conventional unit additions ~~selected by the software tool~~ will be allocated to pricing zones such that each pricing zone approximately meets the

[22] Renewables are not necessarily sited within the pricing zone, but pricing zones can be assigned ownership of the renewable generation

[23] Resource expansion software is not currently adequate for identifying new renewable resources. As resource expansion software improves, SPP may incorporate renewable resources additions in the software as an additional factor for consideration.

reserve margin requirement. Joint ownership of unit additions may be used in order to avoid excessive additions of new resources to individual pricing zones.

External regions also will also be analyzed for resource shortfalls. An appropriate resource plan from the most current neighboring entity's study will be used for their region in the ITP assessment, if readily available and SPP staff and stakeholders find it appropriate. The use of their resource plan is future- specific. If there is not a future comparable to the ITP future, as determined by SPP staff and the ESWG, then conventional additions to address shortfalls shall be added to external regions with a resource mix that is as close as possible to the SPP conventional resource addition mix for that future. For example, if SPP conventional resource additions include 60 percent combined cycleCCs and 40 percent combustion turbineCTs, a ratio as close as possible to this 60/40 ratio would be used to guide conventional resource additions in external regions.

2.2.7.22.2.2.2 *Resource Siting Plan*

2.2.7.2.12.2.2.2.1 Siting Process

The resource plan will identify necessary resource additions which that need to be sited in order to meet study objectives. A spatial location and electrical point of interconnection for each new resource within the SPP region will be selected. This effort will be conducted as a screening level exercise to identify sites and will not be intended to provide or replace a fully scoped power--plant siting study. Siting guidelines are documented in the Resource Siting Manual[24], which is owned and approved by the ESWG and the TWG.

2.2.7.2.22.2.2.2.2 Site Repository

The site repository stores sites, usage, suitability attributes, prioritization, and SPP stakeholder feedback from study to study. Each site is classified by technology type and includes applicable qualitative and quantitative site suitability attributes and qualifications. The Resource Siting Manual will detail how sites will be prioritized and ranked.

2.2.7.2.32.2.2.2.3 Process Flow

The siting process will generally adhere to all of the following steps:

1. Update the site repositories with the latest powerflow and GI generatorion interconnection queue information to account for actual resource development between planning cycles.
2. Post repositories and request applicable SPP stakeholders to provide feedback and additional sites for consideration and supportive rationale.
3. Assess whether the site repositories include an adequate and diverse amount of sites to fulfill the requirements of the resource plan and are representative of remaining technical renewable potential across the SPP region.
4. Develop conventional resource sites and conceptual solar and wind sites as needed.
5. Rank and select sites.
6. Post site prioritization and selections for review.
7. Make any necessary adjustments and repost for approval.

2.2.7.2.42.2.2.2.4 Siting for External Regions

The resource plan for each of the modeled regions external to SPP will be based on the corresponding company's resource plan in their most current regional planning study, as available and appropriate. If this data is not available or appropriate, as determined by SPP staff and the

24 Resource Siting Manual

ESWG, the mix of conventional resource additions will be added to each external region ~~as close as possible to~~to closely resemble those added through the SPP region's resource plan.

~~2.2.7.3~~2.2.2.3 *Generation Outlet Facilities*

Once the resource and siting plans have been finalized, SPP ~~staff~~ will reconsider the First Contingency Incremental Transfer Capability ~~(FCITC)~~ analysis completed during the siting process to develop any necessary generator outlet facilities (GOFs). This GOF process is intended to proxy the evaluation of a resource in the generator~~ion~~ interconnection process to develop necessary upgrades.

Transmission distribution factors (TDFs) will be calculated for each transmission facility with each generation resource at its full nameplate value under system intact and ~~N-1~~ contingency conditions. Overloaded lines with a TDF above the threshold used in the ~~SPP GI~~ generator interconnection process will be used as an indicator that a GOF may be necessary. In the instance that multiple resource plan units are sited with electrically similar interconnection points, the TDFs will be calculated with each resource dispatched at maximum capacity simultaneously to ensure the final GOF is sized appropriately.

When TDFs on overloaded transmission facilities meet or exceed the minimum threshold, GOFs will not be guaranteed for inclusion in the ITP models. SPP ~~staff~~ will use engineering judgment, such as the consideration of a unit's expected dispatch and the impact a GOF may have on potential economic and/or reliability needs, to recommend GOF inclusion.

All GOFs recommended for inclusion in the models will be reviewed and approved by the TWG.

~~2.2.8~~2.2.3 CONSTRAINT ASSESSMENT

SPP maintains a list of flowgates to monitor based on reliability and economic issues seen in real-time~~, however, future constraints may not be known~~. The constraint assessment is used to identify potential future constraints ~~based on assumptions~~ for each future and year of ~~each~~ study.

To create these additional constraints, SPP ~~staff~~ will perform economic simulations to identify additional or breaching elements in the system ~~congestion points~~ that occur during the reliability peak and off-peak hours[25]. System flows under two levels of constraint will be analyzed:

- Copper Plate: No defined constraints.
- Initial constraint list based on NERC and SPP flowgates.

~~2.2.8.1~~2.2.3.1 *Contingency Screening*

Due to software and time limitations, large contingency lists ~~consistent with SPP TPL assessments~~ are not feasible. The contingency lists will be created with the goal of including the most impactful contingencies for constraint identification.

~~Once~~ After the initial economic simulation dispatch results have been created, the resulting contingencies will be limited to the following types of p~~P~~lanning e~~E~~vents identified in the NERC~~SPP~~ Standard TPL-001 ~~standard~~ for the 100 kV-and-above transmission system:

[25] Defined in the Base Reliability Model Overview section

- P1.2 and P1.3 single-branch contingencies on the 100 kV and above system exceeding 50 percent loading in the peak and off-peak hours under system intact conditions for the translated areas.
- P1.2 and P1.3 single-branch contingencies on the 200 kV and above system exceeding 25 percent loading in the peak and off-peak hours under system intact conditions for the SPP footprint.
- Contingencies included in the SPP permanent and temporary flowgates, including P7 events.
- Other P1, P2, P4 and P5 events as potential contingencies.

Contingencies meeting these criteria that are inconsistent with operation of the SPP ~~i~~Integrated ~~m~~Marketplace or create simulation anomalies may be excluded from further evaluation.

~~2.2.8.2~~2.2.3.2 *Constraint Identification*

Facilities exceeding their thermal limits under system intact and contingency conditions will be assessed for potential inclusion as constraints. Flow violations occurring in either of the reliability hours will be automatically included unless SPP ~~staff~~ and stakeholders deem otherwise during the constraint review. Flow violations occurring in the annual hourly simulations will be considered for inclusion based on the following information, at a minimum:

- Number of violation hours and/or violation loading thresholds~~,~~.
- The ability of the simulation to reach a valid[26] dispatch solution due to a given constraint[27]~~,~~.
- Preliminary economic model simulation~~s~~ results~~, and~~.
- Performance of constraints in prior SPP e~~E~~xpansion P~~l~~lan studies.

The ESWG and TWG will be given the opportunity to review the resulting constraints. ~~Once~~ After the review is completed, TWG approval will be requested before completion of the milestone.

In addition to the approved list of constraints, some 69 kV constraints may be included in the constraint list as needed to properly control the dispatch of resources on the 69 kV system and capture congestion in developing 100 kV and above solutions. These constraints will be suggested or provided by SPP stakeholders.

2.3 SPP BA POWERFLOW MODEL OVERVIEW

Each SPP BA powerflow model is an AC powerflow representation of a specific one-hour snapshot of an economic model run with SPP acting as its own balancing authority. Each SPP BA economic model ~~built~~ developed will have two AC powerflow models developed based upon system conditions of a single hour within the year. The two hours represented will be the SPP coincident ~~summer~~ peak hour (peak) and the hour with the highest wind penetration between April and May between the hours of 12~~:00~~ a.m. – 6~~:00~~ a.m. (off-peak). The models will be ~~built~~ developed by matching the dispatch in each powerflow model to the dispatch in the respective hour of the economic model simulations. This process will be described later in the DC/AC Conversion~~DC/AC conversion process~~section. ~~Once~~ After the ~~model~~ conversion is ~~finalized~~complete, SPP ~~staff~~ and stakeholders will assess reactive power flows on the system that the economic modeling tools are

[26] All constraints and generating parameters honored

[27] A constraint may be removed and considered as a reliability need during the SPP BA powerflow analysis

unable to represent. Some of the SPP BA powerflow models will be used to meet the requirements of a sensitivity case necessary for NERC Standard TPL-001 compliance.

AC powerflow models considering a SCUC and SCED solution during SPP coincident peak load and off-peak load conditions will be developed for each future scenario and study year. These models will contain system topology[28] consistent with their respective economic model.

The system operating points for the peak and off-peak AC powerflow will be consistent with the corresponding hours of the economic model simulations utilized in the economic analysis~~, but without forced outages and reactive settings~~.

2.3.1 DC/AC CONVERSION

2.3.1.1 Generation

Unit commitment and dispatch will be determined in the economic model simulation to derive an hourly generation profile for the simulated system. For development of the SPP BA powerflow model, this simulation will not include generator-forced outages and will account for approximated transmission losses modeled in the economic model at the load buses.

2.3.1.2 Load Forecasts

Hourly load values will be calculated for each defined group of demands in the economic model simulation considering annual peak demand and energy, monthly allocations of demand and energy, and the hourly load shape. The resulting load for each group of demands in each hour will be allocated on a pro-rata basis to the individual bus loads assigned to that demand group. The real power demand for each ~~appropriate~~ reliability hour will be incorporated into the AC powerflow models directly from the economic model simulation output. Reactive power demands will be calculated for each bus load based on the power factor of the equivalent load in the respective base reliability model.

2.3.1.3 Interchange

Economic model simulation will determine the exchange of energy between SPP and neighboring systems.

2.3.2 REACTIVE DEVICE SETTINGS

After the DC/AC conversion process is complete, SPP and stakeholders will have an opportunity ~~will be provided for SPP staff and stakeholders~~ to review the settings for transmission facilities that provide reactive support for the transmission system. SPP stakeholders will ~~be asked to~~ submit changes to set points for capacitors, reactors, tap changers for transformers, remote buses, voltage schedules for generators, and static VAR compensators ~~(SVCs)~~. These adjustments will improve the response of the transmission system under system intact and contingency conditions as well as provide confidence to ~~both~~ SPP ~~staff~~ and stakeholders that potential violations are based on realistic system conditions prior to the reliability needs assessment.

~~Once~~ After all reactive device setting adjustments have been received, SPP ~~staff~~ will apply the adjustments to the appropriate models before final posting and approval by the TWG.

[28] System topology includes the transmission network and location of generation, load and reactive devices.

2.4 OPERATIONAL MODEL DEVELOPMENT

After persistent operational needs are identified, SPP staff will identify the most extreme case(s) within each persistent operational need in order to evaluate whether the needs are addressed with proposed solutions. SPP staff will use an eEnergy mManagement sSystem snapshot model for reliability needs and the dDay-aAhead rReliability uUnit cCommitment (DA-RUC) model for economic needs. Times with high -loading or which that require voltage mitigation for each operational need will be selected and the models converted to an ITP model format.

2.5 INTERREGIONAL COORDINATION

During the construction development of each ITP model, SPP will work with external entities to acquire necessary modeling information. Where appropriate, information from recent interregional planning processes will be leveraged. In addition to working with external entities on the front end to request data and information, SPP will also allow them the opportunity to review the models to ensure the accuracy of their respective system. External entities will be allowed given the opportunity to review the models at the same times asconcurrent with SPP stakeholders.

3 BENCHMARKING

3.1 POWERFLOW MODEL

An ITP powerflow model will be validated against ~~the~~ SPP operational data, which may include a comparison of topology and ratings. ITP powerflow models will be ~~further~~ benchmarked against the previous study models, which may include a comparison of topology, generation, load, ratings, and area interchange.

3.2 ECONOMIC MODEL

The year 2 economic model will be utilized to validate modeling parameters to determine if operation is reflective of the SPP system. Data validation may include ~~the following~~: capacity factor by unit type, maintenance outages, operating and spinning reserves, average energy costs, system LMPs (zonal, average, max, etc.), interchange, APC comparison, and renewable generation profiles. Data may be compared to the most recent SPP operational data and previous study models.

4 NEEDS ASSESSMENT

~~Once the models are finalized,~~ SPP ~~staff~~ will conduct economic, reliability, public policy, and operational needs assessments, as detailed in this section, which will result in a comprehensive list of needs to be posted for SPP stakeholders. The Solution Development and Evaluation section further describes the development and submittal of solutions to this needs list.

4.1 ECONOMIC NEEDS ASSESSMENT

The economic needs assessment will be performed in parallel with the reliability, public policy, and operational needs assessments. The economic needs of the system will be identified for each future and study year. Economic model simulations derive nodal LMPs by dispatching generation economically while honoring the transmission constraints defined for the system. LMPs reflect the congestion occurring on the transmission system's binding or breaching constraints. The simulation results will reveal constraints causing the most congestion and the additional cost of dispatching around those constraints. This is the starting point for constraints to be considered for economic needs for the study.

4.1.1 SCUC & SCED ANALYSIS

The economic needs of the system will be identified 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. During the SCUC, 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). The SCUC does not explicitly consider 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 simulation will solve using nodal LMPs, 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.

4.1.2 NEED IDENTIFICATION

The following process will be used to filter and rank the congested constraints of each future and study year to target a list of economic needs for the study:

1. Binding constraints will be ranked from highest to lowest congestion score. Congestion score is defined as the product of a given constraint's average shadow price[29] and the number of hours that constraint is binding.

Figure 2: Congestion Score Formula

~~2.~~ A list of binding constraints will be reduced to the congested flowgates that have greater than $50,000/MW in annual flowgate congestion score. However, additional constraints may be included if SPP ~~staff believes~~determines the inclusion would better define an economic need overall.[30]

~~3.~~2.

~~4.~~3. Constraints with monitored elements not interconnected with the SPP transmission system that provide less than $1 million in annual potential benefit to SPP will be removed unless SPP ~~staff~~ determines ~~that~~ the constraints are related to a target area or a historically congested market-to-market flowgate and warrant further analysis.[31]

[29] The shadow price represents the potential reduction in total SPP production costs if the limit on a congested flowgate could be increased by 1 MW.
[30] As an example, the most congested, unique, monitored element and other constraints with the same monitored element would only be considered one need. Each additional constraint included would better define the economic need overall.
[31] Potential benefit is determined by relaxing the rating of the monitored element of a flowgate to relieve congestion.

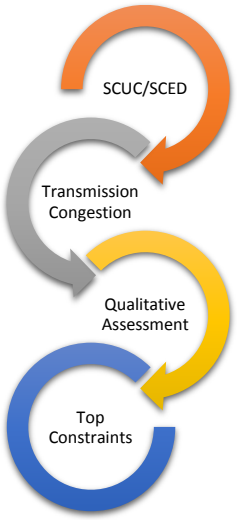


Figure 3: Economic Need Development

The constraint list will be condensed by identifying the target areas (top areas of known or forecasted congestion) ~~in order~~ to more efficiently focus the combined efforts of SPP ~~staff~~ and stakeholders to identify the most valuable solutions. In addition to using congestion scores to rank constraints, SPP ~~staff~~ may also include additional information, such as the relationship of constraints to:

- Each other
- Integrated M~~m~~arketplace congestion[32]
- Operational issues
- Regional Cost Allocation Review (RCAR) issues
- Seams issues
- Operational, reliability, and/or policy needs
- Generati~~on~~or interconnection and transmission service study queue limitations
- Transmission corridors with limited capacity
- Power transfer distribution factor ~~PTDF~~ flowgates used to represent thermal, stability, or contractual limitations
- Facilities that are thermally limited by terminal equipment

In the analysis portion of this milestone, all needs will be reviewed to ~~understand~~ determine the underlying ~~study assumption~~ drivers. Subsequently, a need may be invalidated as a result of further analysis. Generation dispatch, transmission flows, LMPs, and surrounding loads will be among the items considered in identifying the drivers for each need.

[32] SPP ~~staff~~ will relate the economic needs to historic congestion in the SPP Integrated Marketplace and external markets as reported in quarterly and annual market monitor reports.

A more qualitative assessment may be used to limit the number of needs ~~in order~~ to meet the study schedule and objectives. This assessment will consider the number of binding constraints with similar attributes, recommended constraints, and/or target areas for additional analysis, mitigation need dates, general transmission solution lead times, and other project staging considerations.

As part of the needs posting, SPP ~~staff~~ will provide general explanations and rationale surrounding the grouping of constraints as well as high-level scopes for any necessary additional analysis to be performed on economic needs ~~in order~~ to develop a recommended portfolio of projects.

Economic issues in the first-tier areas may be included in the needs list along with an indication that there is potential for seams solutions.

4.2 RELIABILITY NEEDS ASSESSMENT

The reliability needs assessment will be performed in parallel with the economic, public policy, and operational needs assessments. All needs will be identified by assessing the performance of the SPP transmission system under system intact and contingency conditions. SPP will utilize Table 1 from the NERC Standard TPL-001 ~~standard~~[33] as the basis for the contingencies to be assessed during the study. Contingencies that do not allow for non-consequential load loss (NCLL) or the interruption of firm transmission service (IFTS) will be analyzed during the reliability needs assessment. SPP ~~P~~planning ~~C~~criteria[34] will be utilized to determine if a potential regional reliability violation will be considered as a reliability need.

Thermal violations identified in the SPP BA p~~P~~owerflow model during the reliability assessment may not have met the constraint assessment criteria to be defined as a constraint or may be related to a defined constraint in the economic model. Reliability needs will be evaluated for reclassification as an economic need during or after the needs assessment to ensure proper evaluation of system needs. If reclassification is justified, SPP ~~staff~~ will inform stakeholders via email or the SPP website.

4.2.1 BASE RELIABILITY MODEL

Contingency analysis for the base reliability model will consist of analyzing P0, P1, and P2.1 planning events identified in NERC Standard TPL-001 Table 1 for each of the models. The ~~kV~~ voltage level for monitored and contingent elements in the SPP footprint are described in more detail in Table 4.

~~33 NERC TPL-001~~
34 SPP Planning Criteria

	P0, P1, P2.1	
	Monitored Element	Contingent Element
Year 2 Summer	69 kV +	69 kV +
Year 2 Winter		
Year 2 Light Load		
Year 5 Summer		
Year 5 Winter		
Year 5 Light Load		
Year 10 Summer	100 kV+[35]	100 kV+~~31~~[2]
Year 10 Winter		
Year 10 Light Load		

Table 3: NERC Standard TPL-001 Planning Events as Monitored and Contingent Elements

The base reliability models will be analyzed with the remaining contingencies from Table 1 in the NERC Standard TPL-001 ~~standard~~ that do not allow for NCLL or IFTS as detailed in Table 5.

	Other Planning Events[36]	
	Monitored Element	Contingent Element[37]
Year 2~~-~~ Summer	100 kV+	100kV/300 kV+
Year 2 Light Load	100 kV+	100kV/300 kV+
Year 5 Summer	100 kV+	100kV/300 kV+
Year 10 Summer	100 kV+	100kV/300 kV+

Table 4: Remaining Contingencies for Monitored and Contingent Elements

4.2.2 SPP BA POWERFLOW MODEL

Contingency analysis for the BA powerflow models will consist of analyzing P0, P1, and P2.1 planning events identified in NERC Standard TPL-001 Table 1 for each of the models. The ~~kV~~ voltage level for monitored and contingent elements in the SPP footprint are described in more detail in Table 6.

[35] In addition, 69 kV facilities will be both contingent and monitored elements for informational purposes only. ~~T~~This data will inform the solution and portfolio development process to ensure solutions can mitigate violations for the entire study period.

[36] ~~Additional~~ Other p~~P~~lanning ~~E~~events include P2.2, P2.3, P3.1-P3.5, P4.1-P4.5, and P.5

[37] Some ~~P~~planning ~~E~~events allow/disallow NCLL or IFTS based upon the ~~kV~~voltage level of the contingent element~~Will only be run on events that don't allow for NCCL and IFTS~~

	P0, P1, P2.1	
	Monitored Element	Contingent Element
Reference Case Year 2 Peak	100 kV+ with select 69 kV facilities	100 kV+ with select 69 kV facilities
Reference Case Year 2 Off-Peak		
Reference Case Year 5 Peak		
Reference Case Year 5 Off-Peak		
Reference Case Year 10 Peak	100 kV+	100 kV+
Reference Case Year 10 Off-Peak		
F_X Year 5 Peak		
F_X Year 5 Off-Peak		
F_X Year 10 Peak		
F_X Year 10 Off-Peak		

Table 5: NERC Standard TPL-001 Planning Events as Monitored and Contingent Elements

~~These models will be analyzed with t~~The remaining contingencies in Table 1 of the NERC Standard TPL-001 ~~standard~~ that do not allow for NCLL or IFTS will be analyzed~~, only~~ if a violation was observed in the same year/season of the base reliability model as detailed in Table 7.

	Other Planning Events[38]	
	Monitored Element	Contingent Element[39]
Reference Case Year 2 Peak	100 kV+	100kV/300 kV+
Reference Case Year 2 Off-Peak	100 kV+	100kV/300 kV+
Reference Case Year 5 Peak	100 kV+	100kV/300 kV+

Table 6: Remaining Contingencies for Monitored and Contingent Elements

4.2.3 NON-CONVERGED CONTINGENCIES

SPP ~~staff~~ will use engineering judgment to resolve non-converged cases from the contingency analysis. If these contingencies cannot be solved, the potential violations will be identified as reliability needs along with the result of the analysis (e.g. voltage collapse).

4.2.4 FIRST-TIER ~~ANALYSIS~~CONSIDERATION

During the reliability needs assessment, ~~the~~ first-tier areas will be monitored to identify potential reliability needs ~~in those areas~~. After vetting with the appropriate neighboring entity and receiving their consent, ~~the~~ first-tier potential issues will be posted in conjunction with the SPP needs list. The first-tier potential issues list will not serve as solicitation of SPP stakeholders for solutions to address first-tier issues, but the list will be used to evaluate whether there are solutions that address SPP and first-tier issues concurrently.

4.2.5 VIOLATION FILTERING

SPP ~~staff~~ will review the list of potential violations to determine the list of valid violations that will be included in the needs assessment.

As part of the violation filtering, observed thermal overloads in the SPP BA models will receive additional review. The SCUC/SCED simulations honor identified constraints by limiting the dispatch potential of the fleet of generation resources, ensuring constraints will not be overloaded. In theory, a thermal violation should only be considered a reliability need if a constraint was not modeled or breached its thermal limit in the economic simulation. In the instance that an economic constraint or similar monitored element/contingency element pair (mon/con pair) is identified as a thermal overload in the AC contingency results, it will be invalidated as a reliability need. Invalidating these type of thermal overloads will allow the economic potential of the constraint(s) to be evaluated to ~~ensure a~~determine if cost-beneficial solution is available.

4.2.6 LOCAL PLANNING CRITERIA

Local planning criteria ~~(LPC)~~ will be collected from SPP ~~transmission owners (~~TOs~~)~~ in accordance with the SPP t~~T~~ariff. Auxiliary files will be updated with the latest TO ~~LPC~~ local planning criteria

[38] ~~Additional~~ Other p~~P~~lanning e~~E~~vents include P2.2, P2.3, P3.1-P3.5, P4.1-P4.5, and P.5

[39] Some Planning Events allow/disallow NCLL or IFTS based upon the ~~kV~~voltage level of the contingent element.~~Will only be ran on events that don't allow for NCCL and IFTS.~~

information. ~~-~~SPP will request the TOs validate the updated auxiliary files which will be used during the base case and contingency analysis. The local planning criteria~~LPC potential violations~~needs will be posted on a secure website.

4.2.7 SHORT-CIRCUIT ANALYSIS

All short-circuit needs will be classified as reliability needs and will be identified by determining maximum available fault current on the SPP transmission system compared to the respective equipment fault-interrupting duty capabilities under system intact conditions. SPP will monitor all b~~B~~ulk ~~E~~electric ~~S~~system and SPP t~~T~~ariff facilities for the short-circuit analysis.

Year 2 summer peak models will be developed for the short-circuit analysis. These short-circuit models differ from the powerflow models in that all modeled generation and transmission equipment are placed in operation ~~in order~~ to simulate the maximum available fault current.

SPP will simulate three-phase faults and single line-to-ground faults and provide the following analysis results to the TOs as requested~~based on the their request for the fault calculation below~~:

- Full bus-fault current and line-out results using an automatic sequencing fault calculation~~the "ASCC" function of Power Technologies Inc. (PTI) Power System Simulator (PSS/E) software package~~.
- Full bus-fault current and line-out results using an "~~A~~merican ~~N~~ational ~~S~~tandards ~~I~~nstitute" ~~function of PSS/E, and line-out results for buses~~ fault calculation~~.~~

The TOs will be required to evaluate the results and respond to SPP if any fault-interrupting equipment will have its duty ratings exceeded by the maximum available fault current (potential violation). For equipment that is seen to have its duty rating exceeded, the TO will provide SPP with the applicable duty rating of the equipment.

Potential violations of SPP t~~T~~ariff facilities will be identified as a need to be included in the needs assessment. SPP will work directly with the facility owners on all remaining potential violations to ensure that proper mitigation of issues ~~are~~ is completed.

4.3 PUBLIC POLICY NEEDS ASSESSMENT

The public policy needs assessment will be performed in parallel with the reliability, economic, and operational needs assessments, ~~and public policy needs of the system will be identified~~ for each future and study year. Needs driven by public policy arise if the economic simulations identify conditions on the system that keep a utility from meeting its regulatory or statutory mandates and goals as defined by the renewable policy review and/or future specific public policy assumptions identified in the study scope.

~~As appropriate, any public policy issues identified in first-tier areas will be assessed with respect to policy needs for SPP.~~

~~4.5~~4.4 PERSISTENT OPERATIONAL NEEDS ASSESSMENT

Persistent operational needs may be either economic or reliability related~~ and will be included in the posted ITP needs list. The needs identified by th~~is criteria defined in this section will be

~~evaluated using operational models that capture actual historic occurrences. The ORWG, TWG, and ESWG will approve these operational models to ensure consistency with the criteria established to designate the operational needs as persistent, rather than infrequent system needs.~~

~~For issues that do not meet the criteria described in this section~~The criteria for identifying these needs is described in this section.~~,~~ SPP ~~staff~~ may propose additional needs to account for other problematic operational issues observed in operating the transmission system not fitting the given criteria. These additional needs will be presented to the ESWG and TWG for review and endorsement.

~~4.5.1~~4.4.1 ECONOMIC OPERATIONAL NEEDS

SPP ~~staff~~ will classify flowgates meeting either of the following criteria as economic needs:

1. ~~Was~~ The flowgate was congested for at least 20 percent of the previous 24 months, either in a breached or binding state in the real-time balancing market solution, or
2. The flowgate ~~H~~had congestion costs[40] totaling more than $10 million over the previous 24 months.

Periods of time when a flowgate's related congestion is deemed to be the result of prior outage conditions will be excluded from these criteria calculations. Congestion cost for outages will be provided for informational purposes.

SPP ~~staff~~ also will ~~also~~ identify economic needs considering manual commitments of uneconomic generation for local area voltage support, according to either of the following criteria:

1. Manual commitment events ~~which~~ that include startup and extension 25 percent of the year, or
2. Manual commitments that do not exceed 25 percent of the year, but cost over $1 million dollars over 24 months.

~~4.5.2~~4.4.2 RELIABILITY OPERATIONAL NEEDS

SPP ~~staff~~ will classify facilities as reliability needs due to system reconfiguration using agreed upon (by SPP and the transmission operator) operational guides or load shed as a result of unsuccessful control of the system through re-dispatch if they meet the following criteria:

1. High~~-~~ or low~~-~~-voltage issues where system reconfiguration is implemented 10 percent of the year due to non-outage issues[41], or
2. Thermal loading issues where system reconfiguration through the use of an agreed upon operating guide has been implemented in real-time 25 percent of the year.

[40] Congestion costs will be calculated using the same methodology as the SPP violation relaxation limit process.
[41] Switched shunts and generator MVAR adjustments will be optimized prior to needs being identified. If potential non-consequential load loss is 100 MW or greater, the risk to the load would need to be present one percent of the time.

5 SOLUTION DEVELOPMENT AND EVALUATION

5.1 DETAILED PROJECT PROPOSAL ~~(DPP)~~ PROCESS

Pursuant to ~~Attachment O Section III of~~ the SPP t~~T~~ariff and SPP b~~B~~usiness p~~P~~ractice~~s 7650~~, SPP will open a 30-day detailed project proposal (DPP) transmission planning response window in which SPP stakeholders can submit solutions to system needs identified during the needs assessment. ~~SPP stakeholders can submit S~~solutions submitted outside the DPP window ~~for~~ may also be consider~~ed~~ation in solution development and evaluation. ~~, but the corresponding submitter will not be eligible for the incentive points that may be associated with the transmission owner selection process[42].~~ Solutions to the posted needs may include transmission solutions, model ~~corrections~~updates~~d~~adjustments, operating guides, and non-transmission solutions.

5.1.1 SOLUTIONS

During the DPP window, all ~~SPP-stakeholder-developed solutions~~DPP submittals must be submitted ~~to~~ through SPP's RMS for tracking purposes using the most current DPP submittal form, located on the SPP website. This allows SPP ~~staff~~ to track the submission as well as correspond with the individual project submitter. ~~Throughout this process,~~ SPP will develop solutions to the needs posted in the needs assessment in accordance with the project schedule.

5.1.1.1 Transmission Projects

Transmission projects require new, rebuilt, upgraded, or replacement facilities ~~and assume a financial expenditure for implementation~~.

5.1.1.2 Non-Transmission Solutions

Non-transmission solutions are generally considered a method of modifying existing facility settings, inputs, outputs, or other changes to the existing transmission system such that at least one need is mitigated, but can also include new projects such as generation capacity additions. ~~Non-transmission solutions generally do not require an expenditure of funds from any transmission owners, however, there may be a cost associated with a non-transmission solution such as a re-dispatch.~~

5.1.1.3 Model Adjustments

In the instance that a need is included in the needs assessment due to incorrect or out ~~of~~ date~~d~~ information included in any of the models, SPP stakeholders are encouraged to submit ~~any~~ appropriate model adjustments to mitigate the issue.

5.1.1.4 Operating Guides ~~&~~/ Planning Guides

SPP stakeholders can submit current SPP operating guides to mitigate needs. Once submitted, SPP will verify the operating guide is still active prior to solution testing.

5.1.2 SPP ~~STAFF~~ DEVELOPED SOLUTIONS

In addition to solutions submitted by SPP stakeholders through the DPP process, SPP ~~staff will~~may develop solutions internally to mitigate needs.

~~[42] SPP Tariff Attachment Y Section III~~

5.2 COST ESTIMATES

The cost estimates used for projects ~~that are~~ tested in the initial project development phase will be conceptual estimates as ~~defined~~ described in~~by~~ SPP ~~B~~business ~~P~~practices ~~7060~~. The conceptual estimates will be developed by SPP ~~staff~~ and will utilize standardized estimates and multipliers that are based on historical data. Study estimates may be determined for projects during the initial project development if historical data is limited or unavailable.

The ~~highest-ranking proposed~~draft portfolio and high performing projects as determined by SPP that pass the initial screening phase, ~~as~~ detailed in the Portfolio Development ~~portfolio development~~ section of this manual, will be designated for study estimates as ~~defined~~ described in~~by~~ ~~B~~business ~~P~~practices ~~7060~~. The study estimates will provide a more refined cost estimate for potential project approval. Prior to the solution development phase, SPP ~~staff~~ will make a preliminary determination of any proposed upgrades that are potentially competitive according to Attachment Y, Section I, for the limited purpose of determining the appropriate party to prepare the study estimate. SPP, or a designated third party, will prepare study estimates~~A study estimate will be prepared by SPP staff or SPP's designated third party~~ for potentially competitive upgrades. ~~and by the i~~Incumbent ~~transmission owner~~TO(s) will prepare study estimates for potentially non-competitive upgrades. All study estimates will utilize the s~~S~~tandardized c~~C~~ost e~~E~~stimate r~~R~~eporting t~~T~~emplate (SCERT) for all upgrades that are required to complete that project.

5.3 SOLUTION EVALUATION PROCESS

5.3.1 ECONOMIC SOLUTION EVALUATION

All solutions[43] will be evaluated based on their one-year benefit-to-cost ratio (B/C) and 40-year net present value (NPV) B/C, using conceptual cost estimates. If a solution mitigates congestion for an economic need and has at least a 0.5 one-year B/C or a 1.0 40-year NPV B/C, it will be included for further consideration during portfolio development. ~~F~~For the 40-year NPV B/C, the average SPP net plant carrying charge and an in-service date of year 5 will be applied.

Potential seams projects will be identified and flagged as such if they meet either of the following criteria:

- Interconnects SPP with a non-SPP TO~~; or~~
- Adjusted production~~P~~ cost~~C~~ benefit to a neighboring entity is at least 20 percent of total benefit of SPP and the neighboring entity.

~~Once~~ When flagged as a potential seams project, SPP ~~staff~~ will apply a minimum of 20 percent of the total project cost to the applicable neighboring entity. SPP ~~staff~~ will work to determine what level of cost-sharing will make it viable for the SPP entity and whether or not there is an opportunity for cost-sharing with a neighboring entity. SPP ~~staff~~ will work with the appropriate neighboring entity~~(ies)~~ to evaluate any potential seams projects and determine if there is a willingness to proceed jointly.

[43] Regardless of the type of need the solution was submitted to address

5.3.2 RELIABILITY SOLUTION EVALUATION

All solutions[44] will be evaluated against reliability needs. SPP ~~staff~~ will use the following metrics to evaluate potential benefits~~-~~to~~-~~proposed cost~~:~~[45]~~:~~

- Cost per loading relief (CLR) – compares the amount of thermal loading relief provided to the cost of the proposed solution
- Cost per voltage relief (CVR) – compares the amount of voltage support relief provided to the cost of the proposed solution

The CLR and CVR metrics will be calculated for every solution against each need it mitigates. The metric calculations will provide a ranking of the solutions for each need. SPP ~~staff~~ will use the metrics as a tool during project selection for the reliability portfolio development.

Potential seams projects will be identified and flagged as such if they meet either of the following criteria:

- Interconnects SPP with a non-SPP TO~~, or~~
- Addresses an identified first-tier potential reliability issue.

SPP will determine what level of cost-sharing of any potential seams project would make it viable for the SPP region and whether or not there is an opportunity for cost-sharing with a neighboring entity. SPP ~~staff~~ will work with the appropriate neighboring entity~~(ies)~~ to evaluate any potential seams projects and determine if there is a willingness to proceed jointly.

5.3.3 PUBLIC POLICY SOLUTION EVALUATIONS

Policy solutions will be evaluated based upon whether or not they resolve a public policy need. Projects that mitigate public policy needs will be included for further consideration during portfolio development.

5.3.4 PERSISTENT OPERATIONAL SOLUTION EVALUATIONS

A subset of solutions will be ~~selected for evaluation~~evaluated to address persistent operational needs utilizing the filtering criteria, as approved by the TWG, ESWG and ORWG. Reliability solutions will be evaluated by the CLR and CVR metrics described in the Reliability Solution Evaluation ~~reliability solution evaluation~~ section. Economic solutions will be evaluated based on~~ the value of transmission process.~~

~~The value of transmission process involves identifying key operational periods (high wind, high load, etc.) and using change cases to evaluate the production cost savings associated with an upgrade, derate or any change that can be modeled. Actual production DA-RUC models are used in this analysis. Using DA-RUC cases for this analysis allows SPP to use the actual data from the operational period and compare the costs that a particular change created. This creates an accurate assessment of the potential benefits that can be gained with a particular project.~~criteria developed by SPP and stakeholders, which will be detailed in the study scope.

[44] Regardless of the type of need the solution was submitted to address
[45] Relief score calculations can be found in the reliability metrics document approved by the TWG

~~If additional solutions are needed for economic reasons as identified during the persistent operational needs assessment of manual commitments, the average annual make-whole payment over the period studied will be used as the expected benefit provided by the project.~~

The needs will be evaluated using operational models that capture actual historical occurrences. The ORWG, TWG, and ESWG will approve these operational models to ensure consistency with the criteria established in the Persistent Operational Needs Assessment section.

6 PORTFOLIO DEVELOPMENT

6.1 PORTFOLIO DEVELOPMENT METHODOLOGIES

Portfolios will be developed for each need type and evaluated for synergies as described in this section. SPP will consider stakeholder feedback when selecting a portfolio for each future. Specific solutions and the reasoning for inclusion or exclusion in the draft or final portfolios will be available for discussion at the planning summit or other open SPP stakeholder forums such as a working group meetings.

6.1.1 ECONOMIC PORTFOLIO DEVELOPMENT

Solutions mitigating economic needs are ranked by their cost effectiveness, net APC benefit and qualitative benefits for each need or set of needs~~,~~ and categorized into one or more of the following groupings:

- Cost effective: Solutions with the lowest cost with respect to the congestion relief they provide on individual flowgates will be selected.
- Highest net APC benefit: Solutions with the highest difference between one-year APC benefit and one-year project cost will be selected.
- Multi-variable: Top-ranking projects in the other two groupings, as well as qualitative benefits that the other groupings may not capture, will be considered when selecting projects.

In addition to economic performance, consideration of the following information may be given to the top-ranking solutions:[46]

1. One-year project cost, APC benefit, and B/C.
2. 40-year NPV cost, APC benefit, and B/C.
3. Congestion relief that a project provides for the economic needs of that future and year.
4. Project overlap, or when two or more projects that relieve the same congestion are in a single portfolio.
5. The potential for a project to mitigate multiple economic needs.
6. Any potential routing or environmental concerns with projects.
7. Any long-term concerns about the viability of projects.
8. Seam and non-seam project overlap.
9. Individual project robustness, which includes, ~~but is not limited to,~~ event file modification.
10. The potential for a project to mitigate reliability, operational, and public policy needs, which covers current market congestion.
11. The potential for a project to address non-thermal issues.
12. The need for new infrastructure versus leveraging existing infrastructure.
13. Larger-scale solutions that provide more robustness and additional qualitative benefits.

Study estimates for the top-ranking projects from each economic grouping will be developed consistent with the Cost Estimates section of this manual. Once study estimates are applied to the top-ranking solutions in each grouping, th~~e~~at limited set of solutions will be ranked again to reflect the cost refinement.

[46] Additional consideration may result in changes in top-ranking solutions, including elimination of solutions.

The top-ranking economic projects will ~~then~~ be tested in a new set of base models that include the corresponding reliability, policy, and operational economic portfolios. The economic projects will be tested individually within each group to assure only those with at least a 0.9 one-year B/C or 1.0 40-year NPV B/C move forward. ~~A portfolio will be selected for each future by SPP staff considering stakeholder feedback.~~

6.1.2 RELIABILITY PORTFOLIO DEVELOPMENT

Solutions mitigating reliability needs will be ranked and displaced according to the reliability metrics, then assessed from a qualitative standpoint. SPP will review this draft portfolio of solutions to determine if a better overall project can be selected from a qualitative standpoint. ~~Once~~ After SPP ~~staff~~ has reviewed the draft portfolio, study estimates for the top-ranking projects from the reliability grouping will be developed consistent with the Cost Estimates section. Additional study estimates may be developed if a project performs well according to reliability metrics or is considered a high-~~-~~performing project from a qualitative standpoint. ~~Once~~ When study estimates are developed, the reliability metrics are recalculated with the refined cost estimates and the portfolio is updated to consider the impact of SPP stakeholder feedback or solutions that have higher or lower costs than originally estimated. Additional study estimates may be developed until the final reliability portfolio is determined for each future. ~~Specific solutions and the reasoning for inclusion or exclusion in the draft or final reliability portfolios will be available for discussion at the planning summit or other open SPP stakeholder forums such as a working group meetings.~~

6.1.3 PUBLIC POLICY PORTFOLIO DEVELOPMENT

Solutions mitigating public policy needs will be ranked by need based on their APC benefit in relation to their conceptual cost. Once study-level cost estimates are available, the ranking will be adjusted for that limited set of top-ranking solutions based on the updated cost. The highest-ranked project for each need will be selected for a grouping and tested individually within the policy grouping to ensure there is no redundancy of need mitigation within the set of projects.

6.1.4 PERSISTENT OPERATIONAL PORTFOLIO DEVELOPMENT

Solutions mitigating persistent operational needs are ranked by the appropriate metrics depending on whether the need is economic or reliability based. Solutions identified to mitigate persistent operational issues will be compared with the other portfolios to ensure ~~that~~ efficiencies are gained by identifying the minimum number of projects to meet all needs. Economic solutions will be ranked based on their project cost compared to the cost ~~that was~~ incurred without the project. SPP and stakeholders will determine the criteria for development of the operational portfolio. ~~The criteria for projects to move forward into the portfolio will be discussed and determined by SPP staff and stakeholders during the scope development of each study. Details~~which will be included in each study scope. Reliability solutions will be ~~selected~~ evaluated using the CLR and CVR metric concept.

6.1.5 PORTFOLIO SYNERGY

After the economic, reliability, operational, and policy portfolios are selected, checks for redundancy amongst the portfolios will be performed. The most economic set of projects within those portfolios meeting the same set of needs will be selected for further evaluation.

6.2 PORTFOLIO CONSOLIDATION

~~In order t~~To determine a recommended plan, the portfolios of potential projects must be consolidated. SPP~~SPP staff~~ and stakeholders will discuss, determine and document details of the study-specific consolidation criteria during each study scope development.

6.3 PROJECT STAGING

A project implementation plan will be developed for the final consolidated portfolio(s). The final portfolio(s) will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. To help stage the projects, SPP will utilize simulation results for years 2, 5, and 10.

Each project classification will have its own methodology to determine a need date for upgrades to be included in the consolidated portfolio. Step changes between models, such as new generation or transmission upgrades in an area where an upgrade has been identified, may conflict with staging results for methods described in this section. In these instances, SPP~~SPP staff~~ will consider these step changes within the model set to inform need date recommendations. During project staging, SPP~~SPP staff~~ will also consider future assumptions, current market conditions, and other available transmission system information.

If any projects with existing NTCs show an earlier need date than the need date on the NTC letter, SPP~~SPP staff~~ may recommend acceleration of the project.

Staging for each type of project is described in the ~~three~~ following three sections. Staging for persistent operational projects are included in the economic and reliability project sections.

If a project is classified as more than solely economic, reliability, or public policy, the project will be staged to meet the earliest need date established through the single--project classification sections.

6.3.1 ECONOMIC PROJECTS

Projects deemed necessary to meet the economic needs of the system due to persistent operational issues will have a need date the same as the issue date of the NTC.

Other economic projects in the final consolidated portfolio will be staged in the first year that the B/C ratio of each upgrade exceeds 1.0. -A linear interpolation of B/C ratios between each of the study years will be used to determine the need date. For example, an upgrade identified to address an economic need in year 10 will be staged between year 5 and year 10, based on linear interpolation of B/C ratios between the year 5 and year 10 models. Figure 4 represents the linear interpolation of B/C ratios of an upgrade. In this example, if year 5 is 2020 and year 10 is 2025, the need date would ~~be determined to~~ be 2024.

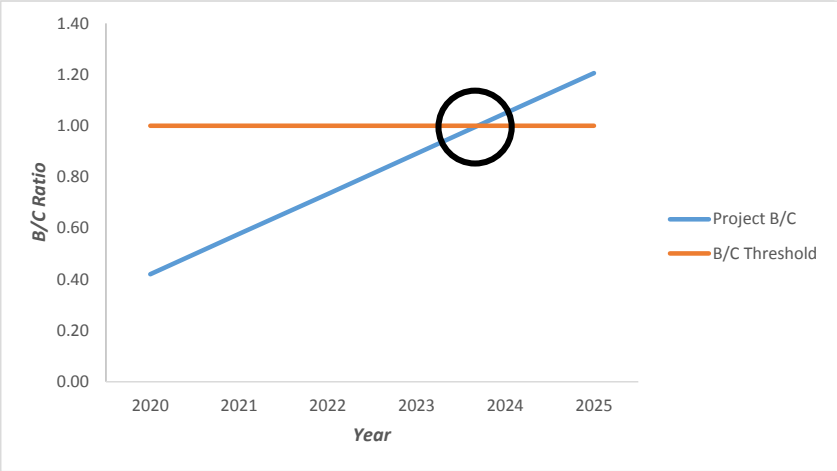


Figure 4: Economic Project Staging Example

6.3.2 RELIABILITY PROJECTS

Projects ~~deemed~~ necessary to meet the reliability needs of the system due to persistent operational issues will have a need date the same as the issue date of the NTC.

Reliability projects in the final consolidated portfolio will be staged based on the year and season when the needs addressed by each project appear on the transmission system. All upgrades ~~which~~ that solve year 2 violations will be initially staged for an in-service date in the corresponding season in which the violation occurs for year 2.

For upgrades that solve reliability needs in year 5 and year 10, the staging process will use a linear interpolation to evaluate thermal loading or the per-unit voltage value of the season in which the violation appears and the previous year's model on record. For example, a violation that occurs in year 5 summer peak will be staged between the summer peaks of year 2 and year 5, based on the results of linear interpolation between the year 2 ~~summer peak~~ and year 5 summer~~-~~peak models. Figure 5 represents the linear interpolation for thermal loading on a transmission line. In this example, if year 2 is 2021 and year 5 is 2024, the need date would be ~~determined to be~~ June 1, 2024.

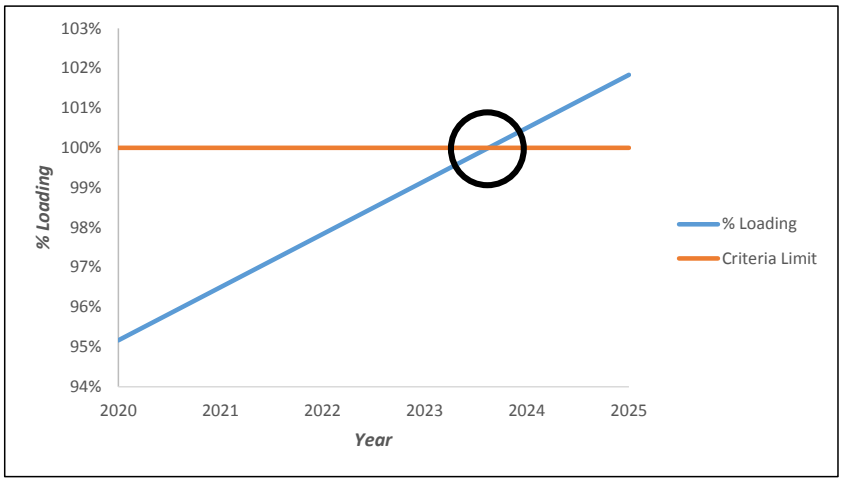


Figure 5: Reliability Project Staging Example

6.3.3 PUBLIC POLICY PROJECTS

Policy projects in the final consolidated portfolio will be staged according to when the public policy needs are resolved. A linear interpolation of the progress towards mitigating the public policy needs between each of the study years will be used to determine the staging date. For example, an upgrade identified to address public policy needs in year 10 will be staged between year 5 and year 10, based on linear interpolation of progress towards mitigating the public policy need between the year 5 and year 10 models. Figure 6 represents the linear interpolation of progress towards resolving a public policy need. In this example, if year 5 is 2020 and year 10 is 2025, the need date would be ~~determined to be~~ 2024.

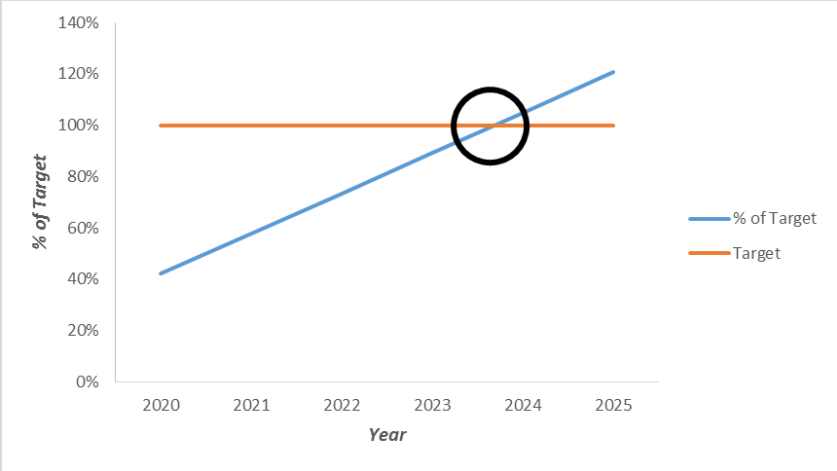


Figure 6: Public Policy Project Staging Example

6.4 FINAL ASSESSMENTS

6.4.1 BENEFIT METRICS

Benefit metrics will be used to measure the value and economic impacts of the final consolidated portfolio to be expected from the ITP ~~planning process~~assessment. Generally, a single portfolio will be tested in the approved future(s) by computing benefits and costs over a 40-year timeframe. For further detail on the metrics in Table 8, refer to the Benefit Metrics Manual.[47]~~.~~

[47] Benefit Metrics Manual

ITP ~~Study~~ Assessment Benefit Metrics
Adjusted Production Cost
Savings Due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Marginal Energy Losses Benefit
Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
Reduction of Emission Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues

Table 7: ITP ~~Study~~ Assessment Benefit Metrics

6.4.2 SENSITIVITY ANALYSIS

Sensitivity analyses will be defined in the scope and conducted to measure the flexibility of the final portfolio in each ITP ~~study~~assessment. Generally, these sensitivities will not be used to select the proposed transmission projects, nor to filter out projects. The sensitivities to be performed on the final portfolio of each ITP ~~study~~ assessment shall include, at a minimum:

- High natural-gas price
- Low natural-gas price
- High demand
- Low demand

Typically, for the demand sensitivities, one standard deviation on either side of the expected values will be used, and for the natural gas price sensitivities, two standard deviations of expected values will be used.

6.4.3 FINAL RELIABILITY ASSESSMENT

~~In order t~~To evaluate and confirm the effectiveness of all identified upgrades for the recommended portfolio, a final reliability assessment will be~~is~~ performed. The base reliability and SPP BA powerflow models will be modified to include the recommended portfolio and model adjustments identified during solution development, regardless of project classification. A contingency analysis will be performed to identify any new reliability violations on this updated set of powerflow models.

If any new reliability violations are observed in the modified base reliability models, the recommended portfolio may be modified with a new or modified solution. ~~If necessary, t~~The final portfolio will include the changes determined from the incremental reliability assessments.

If any new reliability violations are observed in the modified SPP BA powerflow models, they will be documented in the ITP assessment report~~:~~, however, no solutions will be developed. SPP ~~staff~~ will perform a spot check contingency analysis on economic solutions. This analysis will be used to determine the effect of potential dispatch changes as constraints are removed or adjusted due to the solutions and ensure that those changes do not result in additional reliability violations.

The analyses described ~~above~~ in this section will begin as SPP ~~staff~~ develop draft portfolios ~~in an effort~~ to identify projects that may have adverse impacts to the transmission system as quickly as possible.

The results of the final reliability assessment on the recommended portfolio will be documented in the ITP assessment report. Any upgrades added to the recommended portfolio as a result of the final reliability assessment will be identified.

7 DELIVERABLES

7.1 FINAL REPORT

The deliverable for each ITP ~~study~~ assessment will be a report detailing the analysis, results, and recommendations for a cost-effective and robust portfolio(s) that takes into account the likelihood of the future(s) studied. In addition to analysis details and results, a SPP ~~staff~~ recommended transmission plan for the B~~b~~oard to consider for approval will be included in the final report.

Parts of each ITP study report will be incorporated into the annual SPP Transmission Expansion Plan (STEP) report.

8 ISSUANCE OF NTCS

~~Once~~ When projects are approved by the ~~SPP~~ Board, SPP will issue ~~notifications to construct (~~NTCs~~)~~ in accordance with the SPP t~~T~~ariff and SPP b~~B~~business p~~p~~P~~r~~actices.

9 SPP ~~STAFF~~ AND STAKEHOLDER ACCOUNTABILITY

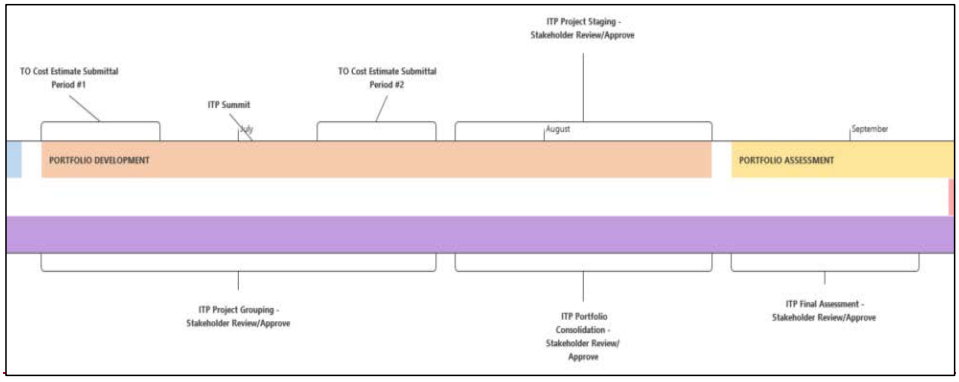
SPP and stakeholders ~~and staff~~ will introduce steps to focus on accountability for timelines and milestones that consist of mechanisms designed to promote the timely exchanges of data, reviews, and approvals within the transmission planning process.

9.1 PROJECT SCHEDULE

SPP ~~staff~~ will develop a project schedule in parallel with the development of the scope of each successive study. This schedule will identify the timing, duration, and responsible parties for all data exchanges, reviews, and approvals required to complete the ITP ~~study process~~assessment. SPP ~~staff~~ will coordinate with SPP stakeholders in the development of this schedule and formally vet the final schedule with SPP stakeholders upon the completion of the study scope.

This schedule will be maintained by SPP ~~staff~~ and regularly reviewed at appropriate SPP stakeholder meetings to keep affected parties informed of upcoming milestones to ~~assist with~~ensure the timely completion of the planning process.

PORTFOLIO DEVELOPMENT	**50 days**	**Mon 6/11/18**	**Fri 8/17/18**
ITP Project Cost Estimates	30 days	Mon 6/11/18	Fri 7/20/18
ITP Project Grouping - Stakeholder Review/Approve	30 days	Mon 6/11/18	Fri 7/20/18
ITP Portfolio Consolidation - Stakeholder Review/Approve	20 days	Mon 7/23/18	Fri 8/17/18
ITP Project Staging - Stakeholder Review/Approve	20 days	Mon 7/23/18	Fri 8/17/18



9.2 POINT OF CONTACT

Clear and timely two-way communication between SPP ~~staff~~ and stakeholders is vital to the successful completion of the annual study process and ~~. T~~the use of a central point of contact (CPOC) ~~is designed~~will ~~to help~~ increase the coordination and timely delivery of information

necessary to meet scheduled milestones. ~~This information can range from modeling data submittals to a requests to push information to SPP stakeholder representatives for upcoming approvals.~~

Using the ~~vetted process~~project schedule described ~~above~~in this section, SPP stakeholders will appoint a CPOC ~~contacts~~ to work with SPP ~~staff~~ to coordinate the timely flow of information. Once provided to SPP, ~~staff,~~ a list of SPP stakeholder contacts will be developed and posted on SPP's secure website, viewable to those with access to the website[48] and corresponding ITP ~~study~~assessment folder.

SPP stakeholders have flexibility when identifying ~~may choose how they address~~ the CPOC for their respective companies~~. Potential options may~~, which include:

- Identifying a specific person who will coordinate the various requests that come out of the planning process.
- Assigning individuals who will be responsible for specific parts of the planning process. For example, identifying a CPOC who will be responsible for coordinating the submission of all data required to support the modeling and planning processes. Another individual may be responsible for project review and cost-estimate submittals.
- Providing SPP ~~staff~~ with an email address ~~that can~~to be used for requests that will target specific groups with their organization instead of naming an individual. For example, modeling@abcinc.com can be used to target the entire modeling team. Email addresses can be provided for company groups that will be responsible for the various parts of the planning process.

~~Using the vetted process schedule described above, SPP stakeholders will appoint contacts to work with SPP staff to coordinate the timely flow of information. Once provided to SPP staff, a list of SPP stakeholder contacts will be developed and posted on SPP's secure website, viewable to those with access to the website and corresponding ITP study folder.~~

9.3 ~~*DATA SUBMISSION, REVIEWS/APPROVALS*~~*SCHEDULE ~~I~~IMPACTS AND MITIGATION*

Stakeholders are responsible for providing the data necessary to model their assets to SPP. All required model data must be received by the specific deadlines and ~~/~~milestones listed in the ITP schedule[49] for model development. The schedule will be provided to all stakeholders and posted on the SPP website.

In the absence of newly submitted data, ~~A~~applicable SPP working groups and SPP ~~staff~~ will agree upon proxy data to be used ~~in the absence of newly submitted data~~ to meet schedule deadlines and avoid process delays. Along with the timely submittal of data, data reviews and required approvals will be conducted by the ~~associated~~ schedule deadlines. ~~The f~~Failure to perform the required review ~~properly and~~in a ~~t~~timely manner ~~s~~hould not cause a delay in the corresponding process. In the event review deadlines are missed, the items requiring review or approval will be used as is and the process will move forward without delay.

Any entity that does not meet the prescribed data exchange, review or approval deadlines and/or want to add or change data used in the study process may make a request for consideration of the proposed data to SPP ~~staff~~. SPP ~~staff~~ will assess the proposed data to determine if the request will have a material impact on study results and schedule. For requests that do not impact the planning

[48] Access to the website can be requested through SPP RMS

[49] Coordination amongst the TWG, ESWG, and MDWG will be necessary as it relates to the model development schedules for the SPP planning processes

process, results or schedule, the data will be included by SPP staff and the study process will continue. For requests that will have an impact on the study process or results and subsequently an impact to the study schedule, the submitting SPP stakeholder will be informed of the potential impact(s) and a waiver request will be required. Along with impacts that may cause the study schedule to be altered, a waiver request may also be required when the SPP -stakeholder-submitted request increases the cost of the study.

SPP staff may also request a waiver if a process issue causes a negative n impact toon the study schedule, results, or if the mitigation of the issue has a negative impact on the SPP budget. SPP staff will assess the issue and provide feedback to the appropriate working group(s) for consideration offor a waiver. Upon a working group recommendation, SPP staff may move forward with a waiver request.

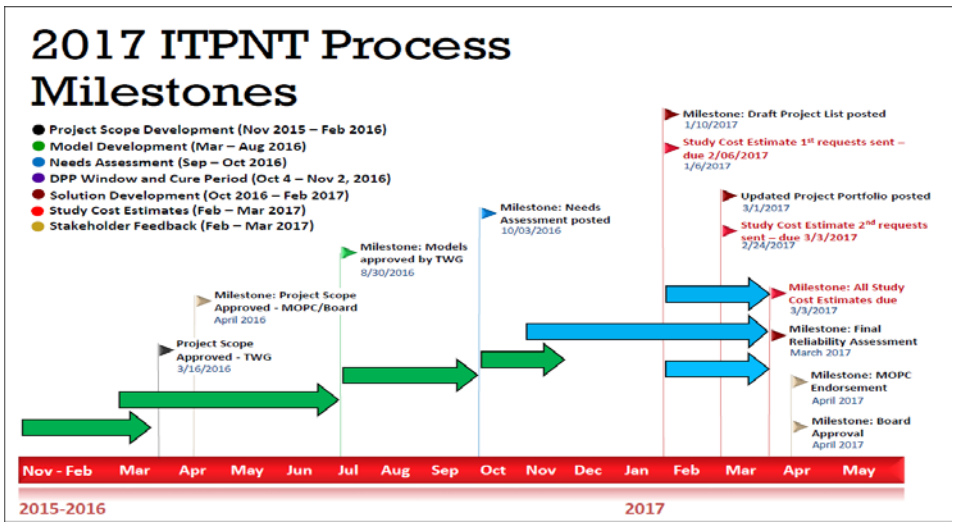
An SPP stakeholder or SPP staff may solicit MOPC for a delay in the posting of the final study report or for the approval of additional effort that would require unbudgeted dollars to augment or provide additional support for SPP staff to meet study schedule milestones in order to meet the posting date of the final study report. The waiver request should include background information on the issue and the rationale for requesting the delay or the need for unbudgeted dollars to support SPP staff's efforts. In support of the waiver process, SPP staff will provide MOPC with the project schedule impacts, schedule mitigation plans and an estimate of any costs associated with accommodating the waiver to support MOPC's decision-making process. The approval of MOPC will be required to adjust the process schedule or incur additional financial costs associated with process mitigation.

With MOPC's quarterly meeting schedule and the need for an immediate resolution of a waiver request, SPP may request that MOPC members may be requested to conduct an out-of-schedule meeting to review and vote on a waiver request. The out-of-cycle meeting may be in the form of a face-to-face, WebEx or teleconference, whichever is most appropriate.

9.4 MOPC REPORT

SPPSPP staff will provide a quarterly report to MOPC highlighting the assessmentprocess milestones from the preceding quarter. Updates will be given on adherence to milestone timelines in regards to data review and submittal, scheduled reviews and approvals, and on issues that may have required mitigation for the process to remain on schedule.

A summary of the participation of SPP and stakeholders and staff will inform MOPC of the attention and importance placed onof the successful completion of milestones and adherence to deadlines critical to produceing a complete, high quality, and timely report and portfolio. Issues requiring mitigation, as mentioned abovepreviously in this section, whether through the actions of SPP staff or stakeholders will be presented in sufficient detail to give MOPC a clear picture of the issue and remedies put in place to avoid potential impacts to the process schedule.


2017 ITPNT Process Milestones
Project Scope Development (Nov 2015 – Feb 2016)
Model Development (Mar – Aug 2016)
Needs Assessment (Sep – Oct 2016)
DPP Window and Cure Period (Oct 4 – Nov 2, 2016)
Solution Development (Oct 2016 – Feb 2017)
Study Cost Estimates (Feb – Mar 2017)
Stakeholder Feedback (Feb – Mar 2017)
Project Scope Approved - TWG 3/16/2016
Milestone: Project Scope Approved - MOPC/Board April 2016
Milestone: Models approved by TWG 8/30/2016
Milestone: Needs Assessment posted 10/03/2016
Milestone: Draft Project List posted 1/10/2017
Study Cost Estimate 1st requests sent – due 2/06/2017 1/6/2017
Updated Project Portfolio posted 3/1/2017
Study Cost Estimate 2nd requests sent – due 3/3/2017 2/24/2017
Milestone: All Study Cost Estimates due 3/3/2017
Milestone: Final Reliability Assessment March 2017
Milestone: MOPC Endorsement April 2017
Milestone: Board Approval April 2017
Nov - Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May
2015-2016
2017

~~*13.0 REVISION REQUEST PROCESS*~~

~~A request to make additions, deletions, revisions, or clarifications to this ITP manual shall be made in accordance with the SPP revision request process[50].~~

~~17~~10 APPENDICES

10.1.1 HISTORY OF THE ITP ASSESSMENT

In January 2009, the SPP Board of Directors (Board) created the Synergistic Planning Project Team (SPPT) to address gaps and conflicts in SPP's transmission planning processes; to develop a holistic, proactive approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities.

The SPPT recommended that the organization adopt a new set of planning principles, develop and implement an ITP assessment, develop a plan to monitor the construction of projects approved through the ITP assessment, identify priority projects that continue to appear in system reviews to relieve congestion on existing constraints, and connect SPP's eastern and western regions. The SPPT recommended the Regional State Committee (RSC) establish a "highway/byway" cost allocation methodology for approved projects.[51]

The SPPT developed an integrated set of principles that should guide SPP in the development of its comprehensive ITP assessment:

1. SPP's primary function is to "keep the lights on," and one way that is accomplished is to provide transmission service for customers within the SPP region. In order to meet this long-term function, SPP must plan for and construct a robust transmission system. This robust transmission system should be large in both scale and geography so as to provide flexibility to meet SPP's future needs.

2. SPP's planning process for a robust transmission system must consider transmission as an enabler to meet short-term and long-term needs. Planning of SPP's transmission system must take into consideration the anticipated location of future generation facilities and should incorporate various scenarios regarding load growth, demand response, energy efficiency, fuel prices, environmental and governmental regulations and policies, and other factors.

3. SPP's planning processes should take a long-term view (20 or more years) of the benefits and costs of all projects while also expediting priority system investments.

4. As a priority, through the RSC and the membership, SPP should resolve the uncertainties associated with financing transmission projects by establishing the appropriate regional cost allocation methodologies. This effort should result in a reduction of the number of cost allocation mechanisms that exist today. SPP members, customers, and interested parties must participate in this effort with their regulators to establish the appropriate cost recovery methods.

5. Once SPP has developed and obtained the approval of a robust transmission plan for the region, the BOD and RSC should ensure that construction is commenced and completed according to an established timeline.

SPP began performing its planning duties in accordance with the ITP assessment in July 2010.

[51] The Highway/Byway methodology was approved by FERC on June 17, 2010.

10.2 THE TRANSMISSION PLANNING IMPROVEMENT TASK FORCE

In February 2015, the Transmission Planning Improvement Task Force (TPITF) was assembled by the SPC and the MOPC and given the responsibility for developing recommendations to improve the regional planning processes. Their objective was to make the SPP transmission planning process more responsive to the effects of the continued growth of SPP's transmission system, changes in the SPP markets, challenges and opportunities presented by changing federal and state energy and environmental regulations and increasing NERC compliance requirements. The TPITF was tasked with reviewing, evaluating and proposing recommendations on the following:

4. The methodologies and modeling practices used in the generator interconnection studies, aggregate transmission service studies, integrated transmission planning (near-term, 10-year, and 20-year assessments), SPP assessments for compliance with NERC TPL standards and the MDWG model development process to ensure effectiveness, consistency and to determine if gaps exist between the various processes.
5. The utilization of data, including data collected by operations, which will benchmark the real-time and planning horizon assessments to ensure consistency in the planning process.
6. The appropriateness of the planning cycle and assessments, including the effectiveness of using production cost modeling in more assessments; development, use and weighting of futures, scenarios and sensitivities; the metrics used to evaluate proposed projects, in particular those that evaluate the impact on rate payers; and planning the transmission system beyond the traditional planning criteria of first contingency ("N-1") in accordance with the approved NERC Standard TPL-001.

The TPITF recommendation whitepaper[52], was intended to represent a consolidated, coordinated approach in planning, managing, and maintaining the SPP transmission system, with a particular emphasis on increasing the availability of transmission service to SPP's customers without unduly compromising system reliability. The recommendations in the TPITF recommendation whitepaper were intended to enable the cost-effective use of capital-intensive generating resources for the benefit of all end-use customers in the SPP footprint and to further develop and enhance policies, tools and practices to optimize the use of the transmission system. The TPITF developed five recommendations to accomplish this scope of work that are discussed in detail throughout this manual:

6. Replace the current ITP schedules with an annual transmission expansion plan.
7. Create a standardized scope.[53]
8. Establish a common planning model for use across the various SPP planning processes.
9. Utilize a holistic planning process.
10. Create SPP staff/stakeholder accountability process for the timely exchanges of data, reviews and approvals.

~~17.1~~10.3 ACRONYMS

Acronym	Term
AECI	Associated Electric Cooperative, Inc.

APC	Adjusted Production Cost
B/C	Benefit-to-Cost Ratio
BA	Balancing Authority
CLR	Cost per Loading Relief
CPOC	Central Point of Contact
CVR	Cost per Voltage Relief
DISIS	Definitive Interconnection System Impact Study
DPP	Detailed Project Proposal
EHV	Extra High Voltage
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
ESWG	[SPP] Economic Studies Working Group
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operation & Maintenance [Costs]
GIA	Generator Interconnection Agreement
GIS	Geographical Information System
IFTS	Interruption of Firm Transmission Service
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
ITP	Integrated Transmission Planning
ITPNT	ITP Near-Term Assessment
ITP10	ITP 10-Year Assessment
LMP	Locational Marginal Price
LPC	Local Planning Criteria
MDWG	[SPP] Model Development Working Group
MISO	Midcontinent Independent Transmission System Operator, Inc.
MMWG	[ERAG] Multiregional Modeling Working Group
MOPC	[SPP] Markets and Operations Policy Committee
MW	Megawatt
MWh	Megawatt-Hour
NCLL	Non-Consequential Load Loss
NERC	North American Electric Reliability Corporation
NERC TPL	NERC Transmission Planning Standards

NPV	Net Present Value
NTC	Notification to Construct
NTC-C	Notification to Construct with Conditions
OATT	Open Access Transmission Tariff
ORWG	[SPP] Operating Reliability Working Group
PPA	Power Purchase Agreement
PST	Phase-Shifting Transformer
PTC	Production Tax Credit
RFP	Request for Proposal
RMS	[SPP] Request Management System
RPS	Renewable Policy Standard
RR	Revision Request
RSC	Regional State Committee
SCED	Security-Constrained Economic Dispatch
SCERT	Standardized Cost Estimate Reporting Template
SCUC	Security-Constrained Unit Commitment
SERC	SERC Reliability Corporation
SPC	[SPP] Strategic Planning Committee
SPP	Southwest Power Pool, Inc.
SPPT	Synergistic Planning Project Team
SSC	[SPP] Seams Steering Committee
STEP	SPP Transmission Expansion Plan
TDF	Transmission Distribution Factor
TO	Transmission Owner
TPITF	[SPP] Transmission Planning Improvement Task Force
TWG	[SPP] Transmission Working Group
VOM	Variable Operation & Maintenance [Costs]
WECC	Western Electricity Coordinating Council

10.4 DEFINITIONS

1. BA Economic Models – model set containing all economic parameters and powerflow data necessary to perform SCUC/SCED simulations
2. BA Powerflow Models – model set containing all powerflow data, including load and generation dispatch from the SCUC/SCED simulations

3. Base Reliability Models – model set representative of how load responsible entities within SPP would serve load utilizing only resources with long-term firm transmission service
4. Balancing Authority – an entity responsible for maintaining a load, generation, and interchange balance within its region
5. Congestion Score – the product of a constraint's annual average shadow price and the number hours the constraint binds; value used to rank economic needs by severity and/or longevity
6. Detailed Project Proposal – a submittal form in which stakeholders may submit solutions to solve ITP needs
7. First-Tier – non-SPP powerflow areas that are interconnected to the SPP system
8. Grouping – specific to economic portfolio development; set of projects that are selected by economic characteristics (cost-effectiveness, net APC benefit, etc.) from initial screening runs and meet a 0.9 one-year B/C or 1.0 40-year B/C within the set of projects
9. Light Load Model – model representative of each submitting entity's one-hour system minimum load between April and May, non-coincident to the SPP system
10. Manual Commitments - a commitment of a resource outside of the automated market process to alleviate constraints
11. Net Plant Carrying Charge - annual percentage that is applied to a utility's depreciated plant costs to calculate an annual revenue requirement billed on Schedule 11 of the SPP Tariff; calculated by a transmission owner's revenue requirement divided by the net transmission plant investment.
12. Notification to Construct: A written notice from SPP directing an entity that has been selected to construct one or more transmission project(s) to begin or continue implementation of the transmission project(s) in accordance with Attachment Y of the SPP Tariff.
13. SPP Open Access Transmission Tariff: SPP governing document filed for compliance with FERC Order 888
14. Reference-Case Future – one future (of up to three) that will be included in each ITP ~~study~~assessment; reflective of a future scenario in which there are no major policy changes
15. Revision Request – an SPP mechanism by which SPP governing documents can be revised through the stakeholder process
16. Seams – areas of or near the boundary of the SPP footprint that are directly impacted by the operation of SPP and non-SPP systems
17. Shadow Price – the potential reduction in total production costs if the limit on a congested flowgate were to be increased by 1 MW
18. State Estimator – a standard industry tool that produces a powerflow model based on available real-time metering information; information regarding the current status of lines, generators, transformers, and other equipment; bus load distribution factors; and a representation of the electric network to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable.
19. SPP Transmission Expansion Plan – The plan that describes the transmission expansion projects being considered over the planning period and developed through the stakeholder process in accordance with the SPP Tariff and approved by the SPP Board.
20. Study Scope – document specific to each individual ITP ~~study~~assessment to be developed by SPP staff and stakeholders containing study assumptions to be utilized that are not included in the ITP Manual
21. Summer Peak Model – model representative of each submitting entity's one-hour system peak load between June and September, non-coincident to the SPP system
22. Winter Peak Model – model representative of each submitting entity's one-hour system peak load between December and March, non-coincident to the SPP system


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

High Priority Study

ESWG/TWG

June 29th, 2017

Today's Goal

- Review any previously presented materials warranting discussion (see sections following slides 5 and 13)
- Review scenario direction from SPC
- Develop high level recommendation on data inputs and analysis scope for MOPC consumption

Overview

Previously Reviewed

Overview

- 2017 ITP10 Additional Analysis review
- April 2017 Board meeting direction
- Proposed study objective
- Proposed data inputs
- Proposed analysis

2017 ITP10 Additional Analysis

- Objective: develop future scenarios to show a range of potential benefits of the Potter to Tolk 345 kV line under uncertainty of assumptions
- Key uncertainty drivers in the 2017 ITP10
  - Load forecasts
    - High projections, recognizing decreases in forecasts year to year
  - Generation forecasts
    - High amount of proxy conventional resources, inconsistent with stakeholder expectations
    - Low assumption of renewable resources, inconsistent with SPP and stakeholder expectations
- Due to the limited objective, this analysis:
  - *Was* able to show the project to be cost beneficial under certain assumptions
  - *Was not* able to determine, with certainty, if the project was the best comprehensive solution
  - Did not evaluate potential transmission needs in other areas that could arise under the studied scenarios

Board Action – April 2017

- The SPP Board accepted SPP staff's recommendation to remove the Potter to Tolk 345 kV line from the 2017 ITP10 portfolio
- The Chairman of the SPP Board directed the development of a High Priority Study scope for consideration in July 2017 in order to appropriately assess the needs in the Texas panhandle

Objective

- Proposed Study Objective
  - Analyze areas of the footprint where historical market congestion may persist or increase over time
- Why study more than the Texas Panhandle?
  - Focus areas of the 2017 ITP10 were the Texas Panhandle (not resolved) and the SPP Eastern Seam (resolved CUS)
  - Most 2017 ITP10 solutions are small upgrades that were intended to provide incremental relief until the impact of changing assumptions and more targeted analysis could be performed in future assessments
  - Scenarios analyzed in the 2017 ITP10 Additional Analysis are likely to impact areas beyond the Texas Panhandle

Data Sources

- Load forecasts, generation, and system topology
  - Utilize the 2018 ITP model series
- Fuel price forecasts
  - Utilize the latest vendor data
- Generation resource plan
  - Leverage the 2017 ITP10 resource plan and SPP generation interconnection queue
  - Incorporate the 12% reserve margin and new load forecast

Other Considerations

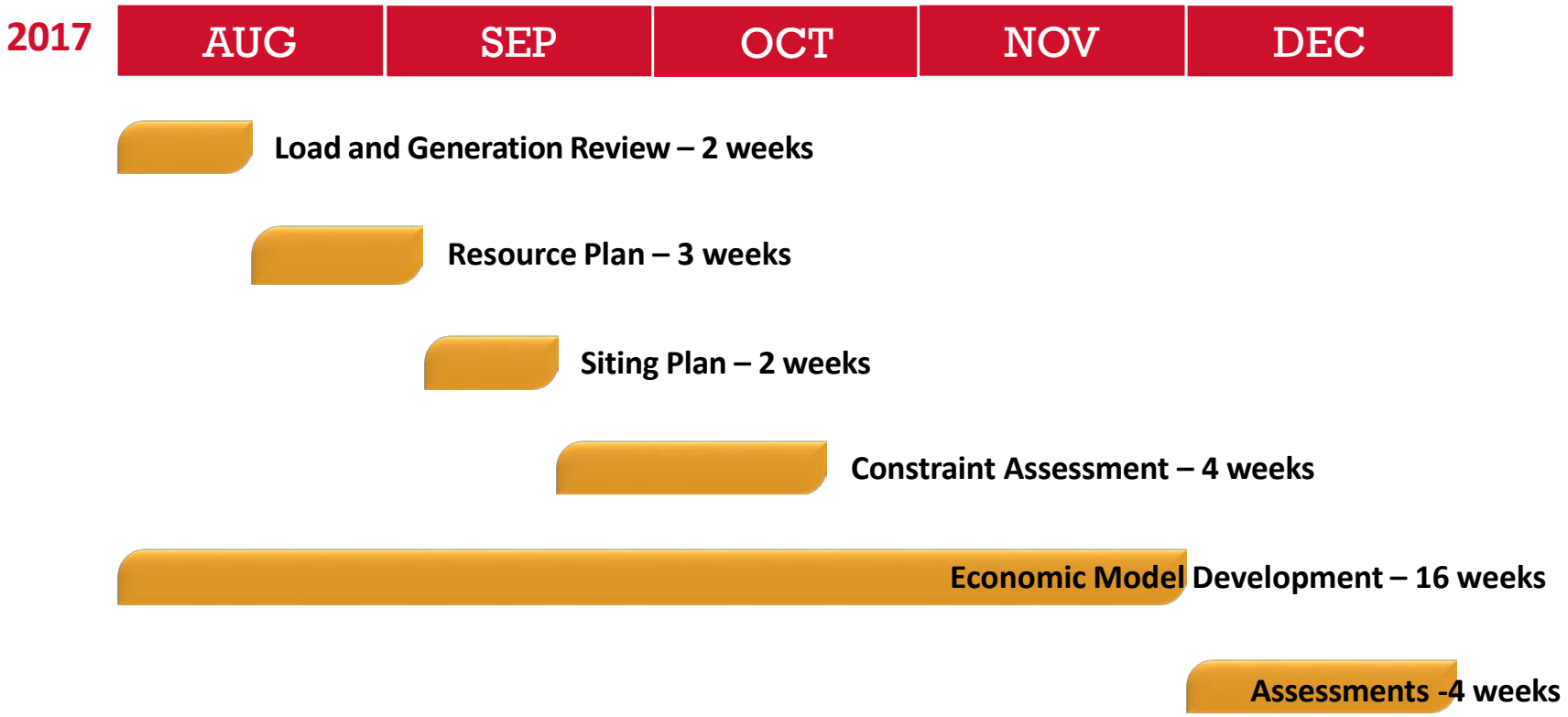
- Resource plan considerations
  - Discuss ways to determine appropriate capacity needs per entity
  - Determine how best to leverage resource adequacy provisions
- Siting white paper concepts

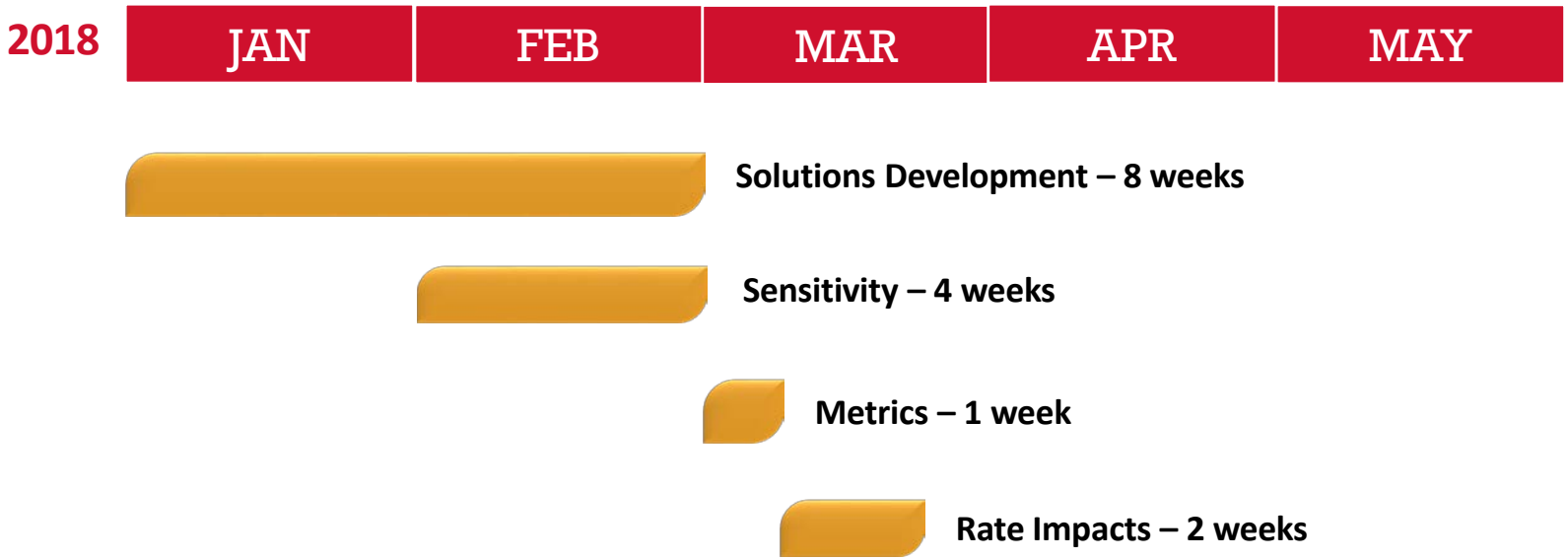
Analysis

- Perform congestion analysis in future scenarios targeting areas of historical congestion
- Perform voltage stability analysis to ensure projected benefits of transmission solutions can be realized
- Perform load and gas price sensitivities on top performing projects to determine if they can stand up to a range of projected benefits

Preliminary Schedule

Previously Reviewed


2017
AUG
SEP
OCT
NOV
DEC
2018
Load and Generation Review – 2 weeks
Resource Plan – 3 weeks
Siting Plan – 2 weeks
Constraint Assessment – 4 weeks
Economic Model Development – 16 weeks
Assessments -4 weeks


2018
JAN
FEB
MAR
APR
MAY
2018
Solutions Development – 8 weeks
Sensitivity – 4 weeks
Metrics – 1 week
Rate Impacts – 2 weeks