Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

May 17th – 18th, 2017

Hilton at the Ballpark – St. Louis, MO

• SUMMARY OF ACTIONS TAKEN •

1. Approved the consent agenda
2. Directed SPP staff to conduct the 2017 Regional Review utilizing the 2017 ITP10 Future 1 and Future 3 2025 sidebar models to calculate a 1-year B/C ratio on the approved Interregional Project [from the 2016 SPP-MISO CSP study].
3. Accepted SPP staff's recommendation of proposed benefit metrics to utilize for the 2017 Regional Review [adjusted production cost and mitigation of transmission outages].
4. Approved the [economic] project screening and portfolio development methodology as presented.
5. Adopted the solutions for external transaction modeling, non-translated region powerflow modeling, and transmission loss assumptions [as improvements to the DC to AC model conversion process].
6. Approved the modeling of DC line limits [for the economic model] based on consideration of operational practice (current or expected future) and/or limit operation to a maximum of expected flows reflected in the AC powerflow models.

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

May 17th – 18th, 2017

Hilton at the Ballpark – St. Louis, MO

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC) called the meeting of the Economic Studies Working Group (ESWG) to order at 1:00p.m., welcomed those in attendance, and asked for introductions.

There were 24 in-person participants and 36 web conference participants, representing 15 of 16 ESWG members. (Attachment 1 – April 20th, 2017 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC) asked for any proxy statements; three proxies were identified. Anita Sharma (AEP) named Jim Jacoby (AEP) as her proxy, Jeremy Severson (BEPC) named Matthew Stoltz (BEPC) as his proxy, and Natasha Henderson (GSEC) named Evan Racine-Johnson (GSEC) as her proxy. (Attachment 2 – Proxy Statements)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC) presented the agenda for review and asked for any additions or corrections. An item regarding nomination and election of a vice-chairman was included after the consent agenda. (Attachment 3 – May17th-18th, 2017 ESWG Agenda).

Jim Jacoby (AEP) made a motion; seconded by Tim Owens (NPPD) to adopt the agenda as modified. The motion was approved unanimously.

Agenda Item 2 – Review of Past Action Items

Kelsey Allen (SPP Staff) reviewed the list of past action items and asked for any comments or questions. (Attachment 4 – Past Action Items)

Agenda Item 3 – Consent Agenda

The consent agenda included the following items:

- Benefit Metrics Manual (Attachment 5 – Benefit Metrics Manual)
- Meeting Minutes – February 15th, 2017 (Attachment 6 – TWG.ESWG Minutes February 15, 2017)
- Meeting Minutes – April 3rd, 2017 (Attachment 7 – April 3, 2017 TWG.ESWG Joint Minutes)

Alan Myers (ITC) asked if any items should be removed from the consent agenda.

The consent agenda was approved unanimously.

Agenda Item 4 – Vice-Chair Nomination/Election

Alan Myers (ITC) opened the floor for additional nominations to the vice-chairman position of the ESWG. Tim Owens (NPPD) had previously been nominated for the position via email. With no further nominees, Tim Owens was unanimously supported to fill the position. Congratulations Tim!

Agenda Item 5 – SPP-MISO CSP Regional Review

Adam Bell (SPP Staff) gave a brief recap of the 2016 SPP-MISO Coordinated System Planning (CSP) study and the project that was approved by the SPP-MISO Interregional Planning Stakeholder Advisory Committee (IPSAC). Adam then reviewed the SPP Regional Review process and the proposed approach to the 2017 Regional Review of the approved project. SPP needs input from the group regarding the model and benefit metrics to use for evaluation of the project. SPP staff's original proposal was to utilize the CSP model developed with MISO for evaluation of the project and include any requested model updates. This would capture many of the model updates already captured for the SPP system and a more realistic representation of the MISO system (the CSP study utilized models containing both RTO's regional approach to the Clean Power Plan (CPP), whereas SPP's 2017 ITP10 model containing the regional approach to the CPP contained MISO's subregional approach). Gayle Nansel (WAPA) questioned the use of the CSP model as it would be a duplication of the work already completed and provide little new information. Zac Hager (OGE) questioned the use of Future 1 (Regional CPP) from the 2017 ITP10 and suggested Future 3 (Reference case) would be more appropriate. Steve Gaw (Wind Coalition) pointed out that the renewable assumptions in Future 1 were more appropriate for SPP, which was followed up by Tim Owens (NPPD) asking SPP how to handle the removal of CPP requirements in Future 1. SPP staff recommended removing carbon adders from Future 1 as additional analysis. Clayton Mayfield (SPP staff) mentioned that because SPP utilized MISO's subregional approach to the CPP in SPP's Future 1 model, their renewable assumptions were much higher than currently expected and were a major driver of benefit for the project in that model. After discussion, the group generally agreed upon utilization of the 2017 ITP10 models and did not want SPP staff spending a lot of time on model updates. Utilizing the 2017 ITP10 sidebar models would contain a majority of model updates but would only allow calculation of a 1-year B/C ratio since only 2025 models were developed. Also, due to concerns of some of the assumptions in the Future 1 model, the group suggested analyzing the project in both Future 1 and Future 3.

Jeremy Severson (BEPC) made a motion; seconded by Gayle Nansel (WAPA) to conduct the 2017 Regional Review utilizing the 2017 ITP10 Future 1 and Future 3 2025 sidebar models to calculate a 1-year B/C ratio on the approved Interregional Project. The motion was approved with one abstention, Bethany King (EDE).

SPP staff recommended that the 1-year benefit calculation consist of adjusted production cost and mitigation of transmission outages.

Tim Owens (NPPD) made a motion; seconded by Kurt Stradley (LES) to accept SPP staff's recommendation of proposed benefit metrics to utilize for the 2017 Regional Review. The motion was approved unanimously.

(Attachment 8 – SPP-MISO CSP Regional Review)

Agenda Item 6 – SPP Staff and Stakeholder Accountability

English Cook (SPP Staff) reviewed the most recent document regarding SPP staff and stakeholder accountability for the new ITP process. (Attachment 9 – SPP Staff and Stakeholder Accountability)

Agenda Item 7 – ITP Scope Standardization

Agenda Item 7a – Economic Project Screening and Portfolio Development

Clayton Mayfield (SPP Staff) presented an updated version of SPP's proposed approach to economic project screening and portfolio development considering discussion from the April meeting. The group spent time discussing the process and the provided flowchart and was generally agreeable to the proposal. Jody Holland (SCMCN) raised concern regarding co-optimization of the different portfolios (reliability, economic, policy) and the potential for reclassification of a project type. (Attachment 10 – Economic Project Screening and Portfolio Development) (Attachment 11 – Economic Project Screening and Portfolio Development Flowchart)

Jody Holland (SCMCN) made a motion; seconded by Tim Owens (NPPD) to approve the project screening and portfolio development methodology as presented. The motion was approved unanimously.

Agenda Item 7b – DC to AC Model Conversion

Kelsey Allen (SPP Staff) gave a recap of the DC to AC model conversion process, the issues identified in the 2017 ITP10 and the approach to address them, and potential adjustments to key parts of the process to help minimize issues in the future. SPP staff recommended that the proposed adjustments to the modeling of external transactions, modeling of non-translated region powerflow data, and approach to transmission loss approximations be adopted for future implementation. Kelsey Allen pointed out that the proposed improvements to modeling of phase-shifting transformers was already approved. Tim Owens (NPPD) recognized that many of these details would not be included in the ITP manual and requested that SPP staff ensure the issues and adjustments to the process are well documented internally to SPP. (Attachment 12 – DC to AC Model Conversion)

> **Kurt Stradley (LES) made a motion; seconded Pat McCool (KCPL) to adopt the solutions for external transaction modeling, non-translated region powerflow modeling, and transmission loss assumptions. The motion was approved unanimously.**

Agenda Item 7c – DC Line Modeling-Economic Model

Kelsey Allen (SPP Staff) reviewed the historical practice of modeling DC lines in the economic model and proposed adjustments for the new process. He recommended that the language for the ITP manual contain less specificity but that the case-by-case details would be documented for internal processes. (Attachment 13 – DC Line Modeling)

> **Jim Jacoby (AEP) made a motion; seconded by Gayle Nansel (WAPA) to model DC line limits based on consideration of operational practice (current or expected future) and/or limit operation to a maximum of expected flows reflected in the AC powerflow models. The motion was approved unanimously.**

Agenda Item 7d – Hydro Transaction Modeling

Kelsey Allen (SPP Staff) gave a brief overview of the purpose of hydro transaction modeling and SPP staff's progress on improvements to the methodology. James Bailey (SPP staff) added some specifics of the issues and potential solutions. After short discussion, Kelsey Allen suggested that the modeling of hydro transactions be removed from the list of items to be standardized and included in the ITP manual and that SPP staff would work with the impacted stakeholders directly to come to a resolution for the new process and create a process document that could be shared with interested parties. The group was agreeable to this approach.

Closing Items

Chair Alan Myers (ITC) requested other items meriting discussion.

List of action items from the meeting: None.

The meeting was adjourned at 11:30 PM.

Respectfully Submitted,

Kelsey Allen

ESWG Secretary

SPP Southwest Power Pool

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP MEETING

May 17-18, 2017

Hilton at the Ballpark – St Louis, MO

• ATTENDANCE LIST •

Name	Company
Amber Gres	SPP
Jason Davis	SPP
Walt [illegible]	Missouri PSC
Michael Wegner	ITC
Tim Owens	NPPD
Kurt Stradley	LES
Don Frerking	KCP&L
Zac Hager	OGE
Alan Myers	ITC
Bethany King	EDE
Eric Burkey	SCMCN
Bryan Rushing	Quanta Technology
Ryan Yokley	Sunflower
Jody Holland	SCMCN
[illegible]	Wind Coalition
Gayle R Mansil	WAPA
Kelsey Allen	SPP

SPP Southwest Power Pool

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP MEETING

May 17-18, 2017

Hilton at the Ballpark – St Louis, MO

• ATTENDANCE LIST •

Name	Company
DON FRERKING	KCP+L
Pat McCool	KCPL
KURT STRADLEY	LES
Tim Owens	NPPD
Michael Wegner	ITC
Charles Hendrix	SPP
Jason Davis	SPP
Kirk Hall	SPP

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ECONOMIC STUDIES WORKING GROUP MEETING

May 17-18, 2017

Hilton at the Ballpark – St Louis, MO

• ATTENDANCE LIST •

Name	Company
Jody Holland	SCMCN
Ryan Yokley	Sunflower
JULIANO FREITAS	SPP
Jim Jacoby	AEP
ZAC HAGER	OG+E

SPP Southwest Power Pool

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ECONOMIC STUDIES WORKING GROUP MEETING

May 17-18, 2017

Hilton at the Ballpark – St Louis, MO

• ATTENDANCE LIST •

Name	Company
BRYAN RUSHING	QUANTA TECHNOLOGY
Eric Burkey	SCMCN
Steve Gaw	Wind Coalition
BRIAN JOHNSON	AEP

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ECONOMIC STUDIES WORKING GROUP MEETING

May 17-18, 2017

Hilton at the Ballpark – St Louis, MO

• ATTENDANCE LIST •

Name	Company
Amber Greb	SPP
Walt Cecil	MoPSC
Rodney Massman	MoPSC
Bethany King	EDE

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Bryan Rushing		Quanta Technology	In Person
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Jody Holland		SCMCN	In Person
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Kirk Hall		SPP	In Person
Kurt Stradley		LES	In Person
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Steve Gaw	rsgaw1@gmail.com	Wind Coalition	In Person
Tim Owens (NPPD)	tjowens@nppd.com	NPPD	In Person
Walt Cecil		MoPSC	In Person
Zac Hager		OGE	In Person

1. Anita Sharma proxy to Jim Jacoby

From: Sharma, Anita
Sent: Wednesday, May 10, 2017 7:38 PM
To: Kelsey Allen <kallen@spp.org>
Cc: Jacoby, Jim <jwjacoby@aep.com>
Subject: **External Email** ESWG Meetings May 17-18

Hello Kelsey,

Due to some prior work commitments that could not be changed, I am unable to attend the ESWG meetings next week and assign my proxy to Jim Jacoby.

Thanks
Anita Sharma
Principal Engineer
American Electric Power
614-753-5908

2. Jeremy Severson proxy to Matthew Stoltz

From: Severson, Jeremy
Sent: Wednesday, May 17, 2017 8:15 AM
To: Kelsey Allen <kallen@spp.org>; Myers, Alan <amyers@itctransco.com>
Cc: Stoltz, Matthew <mstoltz@bepc.com>
Subject: **External Email** ESWG proxy

Hi Kelsey and Alan,

I would like to pass my proxy onto Matt Stoltz. I will be in and out of the meeting today as I am going be attending my daughters 5th grade track meet. I should be at most of the meeting but just in case I will pass the proxy to Matt in case a voting item comes up.

Regards,

Jeremy..

3. Natasha Henderson proxy to Evan Racine-Johnson

From: Henderson, Natasha
Sent: Wednesday, May 17, 2017 7:39 AM
To: Kelsey Allen <kallen@spp.org>; Myers, Alan <amyers@itctransco.com>
Cc: Evan Racine-Johnson <ERacine-Johnson@gsec.coop>
Subject: **External Email** Proxy for ESWG 5/17-5/18

Evan will have my proxy for the next 2 days.

Natasha Henderson
Manager of Strategic Planning
Golden Spread Electric Cooperative
nhenderson@gsec.coop
(806)316-9581

"It is far better to foresee even without certainty than not to foresee at all. "

--Henri Poincare

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

May 17th - 18th, 2017

Hilton at the Ballpark – St. Louis, MO

• A G E N D A •

Wednesday 1:00pm – 5:00pm

Thursday 8:00am – 12:00pm

1. Administrative Items
   a. Call to Order, Introductions..Alan Myers (5 minutes)
   b. Receipt of Proxies ....Kelsey Allen (1 minute)
   c. Review of Agenda[1] ....Alan Myers (1 minute)
2. Review of Past Action Items[1] ....Kelsey Allen (5 minutes)
3. Consent Agenda[1] (Approval Item)..Alan Myers (1 minutes)
   a. Benefit Metrics Manual
   b. Meeting Minutes – February 15th, 2017 (ESWG/TWG)
   c. Meeting Minutes – April 3rd, 2017 (ESWG/TWG)
4. Vice-Chair Nomination/Election... All
5. SPP-MISO CSP Regional Review[1] (Approval Item)...Adam Bell (60 minutes)
6. SPP Staff and Stakeholder Accountability[1] ....English Cook (30 minutes)
7. ITP Scope Standardization.. SPP Staff (240 minutes)
   a. Economic Project Screening and Portfolio Development[1] (Approval Item) (Clayton Mayfield)
   b. DC to AC Model Conversion[1] (Approval Item) (Kelsey Allen)
   c. DC Line Modeling-Economic Model[1] (Approval Item) (Kelsey Allen)
   d. Hydro Transaction Modeling
8. Closing Items..All (5 minutes)
   a. Summary of Action Items (Kelsey Allen)
   b. Future Meetings
      i. June 15th, 2017: 8th Floor AEP Offices, Dallas, TX

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[1] Background Material Included

ii. July 20th, 2017: 8th Floor AEP Offices, Dallas, TX
iii. August 16th-17th, 2017: Grand Hyatt, Denver, CO
iv. September 14th, 2017: 8th Floor AEP Offices, Dallas, TX
v. October 12th, 2017: 8th Floor AEP Offices, Dallas, TX
vi. November 15th-16th, 2017: SPP Corporate Offices, Little Rock, AR
vii. December 14th, 2017: 8th Floor AEP Offices, Dallas, TX

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

May 17th-18th, 2017

	Action Item	Date Originated	Status	Comments
057	SPP staff will write a straw-man procedure or portion of the ITP manual that deals with conventional and wind generation planning and siting within the ITP process. The process should be in place by the Spring of 2015.	August 23rd, 2012	In Progress SPP Staff	A draft resource siting whitepaper will be developed for review mid-2016. April 2017: currently targeting 2 weeks first week in May 2017 for draft.
151	SPP staff to look into optional software tools for use in ITP studies.	May 20th, 2015	In Progress SPP Staff	Staff is meeting with software vendors and users and expects to have a recommendation on any potential resource planning software changes by 4th quarter 2016. February, 2017: Presentation on EGEAS. Hold on investigation of alternatives until EGEAS and ABB's new Capacity Expansion tool are able to be fully tested and compared.
160	SPP staff and the ESWG are to formalize standard procedures for data requests and member review of information related to ITP studies.	January 21st, 2016	In Progress SPP Staff/ESWG	Combined item representative of AI148 and AI149.
163	SPP staff and members to prepare for discussion on scope standardization and prioritization of discussion items.	April 21st, 2016	In Progress SPP Staff/Members	Ongoing.
165	ESWG to review the assumed benefit of mandated reliability projects	May 13th, 2016 RARTF	In Progress ESWG	
166	ESWG to review the impacts of using the system reconfiguration hybrid approach for the Assumed Benefit of Mandated Reliability Projects	May 13th, 2016 RARTF	In Progress ESWG	
167	ESWG to review the classification of	May 13th,	In Progress	

	projects in the ITP process	2016 RARTF	ESWG	
168	SPP staff and the ESWG to evaluate the issues seen in the DC to AC model conversion process.	May 18th-19th, 2016	In Progress SPP Staff/ESWG	February, 2017: Provided an update on issues and potential solutions.
172	SPP staff to develop examples and language for tackling synergies of power flow and economic generation data.	June 16th, 2016	In Progress SPP Staff	October 20th: ESWG approved a methodology for the ITP standard scope. Discussions should continue with SAWG for coordination of methodology, as appropriate.
173	SPP staff to develop a process for annual update of the economic model with vendor data.	June 16th, 2016	In Progress SPP Staff	
183	SPP staff to perform transmission outage analysis in the first part of 2017 to determine the appropriate APC benefit percentage to utilize for the mitigation of transmission outages benefit metric.	September 15th, 2016	In Progress SPP Staff	
184	ESWG to have a future agenda item for education and discussion of the derivation and use of the net plant carrying charge (NPCC) value used in the ITP process for project cost calculations.	April 20th, 2017	In Progress ESWG	

Benefit Metrics Manual

~~November~~May 8, 2017~~6~~

Southwest Power Pool

Revision History

Date	Author	Change Description	Comments
April 20, 2015	SPP Staff	Initial Draft	
November 8, 2016	SPP Staff	Added APC example 2.2.4	
May 8th, 2017	SPP Staff	Updated 40 year language	

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Table of Contents

Section 1. Introduction

1.1. Purpose

This manual documents the benefit metrics currently used in SPP economic studies. The definitions, concepts, calculations, and allocation methodologies for all currently approved metrics are included to ensure open and transparent communication of each metric's purpose and the elimination of any "double-counting" that might occur through the use of these metrics when calculating the benefit of transmission projects.

Any additions, removals, or modifications of benefit metrics approved by SPP stakeholder groups in the future will result in an update to the Benefit Metrics Manual.

1.2. Background

Since the earliest economic studies were being developed by SPP, Staff and stakeholders have been looking for ways to properly assess the benefits of transmission upgrades. The earliest economic studies included Adjusted Production Cost (APC) Savings as the measure of benefit for new transmission. In Priority Projects and the initial ITP studies, benefits of new transmission were expanded beyond APC Savings to include other benefits, such as benefits from reduced transmission losses and from levelization of LMPs.

In January 2012, the Regional Allocation Review Task Force (RARTF) directed the Economic Studies Working Group (ESWG) to develop and monetize benefit metrics for use in the Regional Cost Allocation Review (RCAR). The ESWG initiated the Metrics Task Force (MTF) with the specific purpose of developing tangible dollar-oriented measures and metrics for use in economic evaluations. This included the RCAR as well as other future studies.

The MTF approached this as a brainstorming effort followed by refining of the most promising alternatives. Members contributed ideas based on existing metrics as well as new ideas. The MTF developed numerous metrics, and monetized as many of them as possible. The MTF Report detailed all of their metric development work, and was approved by the ESWG and MOPC in 2012. The monetized metrics were approved by the RARTF to be used in the RCAR.

In 2014, the MOPC directed the ESWG to review the benefit metrics that were developed by the MTF, in order to determine any additions or modifications to the metrics that should be made for future studies. There were some modifications to a few existing metrics, as well as the addition of two metrics that were previously included in the MTF Report, but had not been fully developed and monetized for use in RCAR. These two newly-monetized metrics were the Marginal Energy Losses and Increased Wheeling Through and Out Revenues metrics. These additions and modifications to benefit metrics were approved in July 2014.

This document provides definitions, concepts, calculations, and allocation methodologies for all metrics as approved by SPP membership as of the last date in the Revision History of this document.

1.3. Current Benefit Metrics

The following benefit metrics are those currently used in SPP's economic studies.

- Adjusted Production Cost Savings
    - Includes Reduction of Emission Rates and Values

- Includes Savings Due to Lower Ancillary Service Needs and Production Costs
- ~~Reduced~~ Capacity Cost ~~s~~Savings Due to Reduced On-Peak Transmission Losses ~~on Peak~~
- Avoided or Delayed Reliability Projects
- Mitigation of Transmission Outage Costs
- Assumed Benefit of Mandated Reliability Projects
- Marginal Energy Losses
- Increased Wheeling Through and Out Revenues
- Benefit from Meeting Public Policy Goals

Section 2. Adjusted Production Cost Savings

2.1. History

The Adjusted Production Cost (APC) Savings metric was identified and utilized in Balanced Portfolio, Priority Projects, and ITP studies. It was documented in the 2012 MTF Report, and has not changed since that time.

2.2. Description

The standard APC metric currently used by SPP is a measure of the impact on production cost savings by considering Locational Marginal Price (LMP) for purchases and sales of energy between each area of the transmission grid. The APC for a zone (e.g., a utility) is determined using a production cost modeling tool that accounts for hourly commitment and dispatch profiles for one simulation year. The calculation, performed on an hourly basis, is as follows:

Production costs = The fuel and non-fuel operations & maintenance (O&M) costs of utility-owned or cost-of service-contracted generation.

Revenue from Sales = MW Sold by Zone × Avg. Zonal Generation-Weighted LMP

Cost of Purchases = MW Purchased by Zone × Avg. Zonal Load-Weighted LMP

This APC metric quantifies the monetary cost associated with fuel costs, generation dispatch, grid congestion, energy purchases, energy sales, and other factors that directly relate to energy production by generating resources in the SPP footprint.

2.2.1. Reduction of Emission Rates and Values

The APC calculation also captures the cost savings associated with reduced SO_2, NO_X, and CO_2 emissions by considering allowance prices for these pollutants. The quantified changes in SO_2, NO_X, and CO_2 emissions can be reported within the APC results in order to provide further insight into system expectations. Note that Business as Usual scenarios have not typically included an allowance price for CO_2 emissions.

The allowance market dynamics that take place separately from events in the energy market are not considered in this APC Savings metric. Rather, a simplified approach that assumes allowances are sold and purchased at known market clearing price is applied and these allowance prices are included in the calculation of marginal production costs.

2.2.2. Savings Due to Lower Ancillary Service Needs and Production Costs

Ancillary Services (A/S) are essential to the reliable operation of the electrical system. A number of operating reserves and products fall into this category—spinning reserves, ramping (up/down), regulation, 10-minute quick start. Current production cost simulation tools account for energy costs on the system, and model A/S needs by setting aside an exogenously-determined quantity of A/S reserves in each hour. However, new transmission projects can contribute to reduction in A/S system costs through a reduction in the cost of procuring that quantity.

The cost of providing A/S is captured in the APC Savings metric, as the simulation software captures and simulates A/S requirements and their deployment. The production cost simulation will be conducted using the initial A/S needs for the base case and the same A/S needs for the change case. The difference in APC for the simulations will then reflect the reduced costs of procuring the specified A/S needs (e.g., lower procurement cost of the same A/S needs due to reduced transmission congestion that makes lower-cost resources available to provide A/S).

As an example, the amount of regulation and spinning reserves will be an input to production cost simulations. To the extent possible, the simulation software will "hold aside" an equal amount of committed (i.e., spinning) generating capacity to satisfy the specified quantity of regulation and spinning reserves. The costs of keeping committed capacity "held aside" will be reflected in the simulations' production cost estimate. If transmission reduces A/S-related production costs, the change will be captured as part of APC Savings.

2.2.3. Limitations of the Standard APC Benefit

It is important to understand the limitations of this metric as used in the ITP process. In particular, there are some production-cost-related savings that are not captured in the standard APC metric. This is the case because the standard APC results are typically based on production cost simulations for a base case and a change case that include a number of simplified assumptions, including:

- The simulations assume that transmission facilities are available 100% of the time, thereby ignoring any maintenance and forced outages of transmission facilities
- The simulations assume that the MWh quantity of losses is fixed and does not change with transmission additions, thereby ignoring that transmission expansion may reduce the MWh quantity of losses that need to be supplied.
- The simulations tend to assume that hourly wind generation is perfectly known when generation units are committed for the next day, thereby ignoring the fact that the hourly level of wind generation is uncertain.
- The calculation of APC is based on a number of simplifying assumptions regarding the extent to which congestion costs can be hedged through auction revenue rights (ARRs) in a day 2 market environment. For example, it assumes congestion between owned generations and load can be fully hedged while none of market-based purchases would be hedged.

Some of the transmission-related benefits not captured in the standard APC metric due to these simplified assumptions have been identified and monetized through other benefit metrics such as Mitigation of Transmission Outage Costs and Marginal Energy Losses.

2.2.4. APC Example

This example considers two zones for a single hour. Each zone has a single load, and a single generator dispatched as follows:

- Zone A
  - 200 MW load
    - LMP at load = $40/MWh
  - 150 MW generation
    - Production cost is $83/MWh
    - LMP at generator = $60/MWh

- Zone B
  - 300 MW load
    - LMP at load = $35/MWh
  - 350 MW generation
    - Production cost is $42/MWh
    - LMP at generator = $30/MWh

Based on these numbers, Zone A is a purchaser and has no sales. Zone B is a seller and has no purchases. The calculation of APC for each zone is shown below:

$APC_{Zone\ A}$ = Production Costs + Purchases = ($83/MWh)*(150 MW) + (50 MW purchases)*($40/MWh Load-Weighted LMP) = **$14,450**

$APC_{Zone\ A}$ = Production Costs – Sales = ($42/MWh)*(350 MW) – (50MW sales)*($30/MWh Gen-Weighted LMP) = **$13,200**

Section 3. ~~Reduced~~ Capacity Cost Savings Due to Reduced Transmission On-Peak Losses ~~on Peak~~

3.1. History

This metric was identified and monetized in the early ITP process, and is identified in the 2012 MTF Report. It has not changed since that time.

3.2. Description

Reduced capacity expansion costs due to transmission losses on peak captures the value for the generation capacity that may no longer be required due to a reduction in losses during the system peak. This value can be monetized using the savings in capital attributed to the corresponding reduction in installed capacity requirements. These capital savings can be calculated by applying the estimated net cost of new entry (Net CONE) to the reduction in installed capacity requirements.

The MW value of loss reduction will be multiplied by the Net CONE, assuming the new unit is a combustion turbine (CT). The cost of the CT is used in order to stay on the conservative side of monetizing the benefit, as CTs are generally have the lowest capital cost. It is also multiplied by 1.12, to account for the impact of the loss reduction on the 12% capacity margin. MW loss reductions are calculated for each area, in order to compute the reduced capacity expansion costs by area.

Net CONE is the difference between the annualized cost of new entry (CONE) and the expected annual energy and ancillary service profits a unit of this type is expected to earn in the energy and ancillary service markets. The CONE value can be obtained by levelizing investment costs and fixed operating costs of a combustion turbine as reported in the latest version of the Department of Energy Annual Energy Outlook report or another comparable public source. The following sources may be used to estimate the average annual energy and ancillary service profits for a combustion turbine:

- Historical market revenues net of fuel and variable non-fuel operating costs for combustion turbines in SPP or similar market(s)
- Revenues net of fuel and variable non-fuel operating costs for combustion turbines obtained from production cost simulations of the SPP or similar market(s)

Net CONE is then calculated as the difference between CONE and the estimated energy and ancillary service profits.

Section 4. Avoided or Delayed Reliability Projects

4.1. History

This metric was identified and monetized in the early ITP process, and is identified in the 2012 MTF Report. It has not changed since that time.

4.2. Description

Economic or policy projects are classified as such because they enable economic benefit to members that exceeds the cost of the project or enable renewable policy standards to be met. However, as a secondary benefit, economic and policy projects can also help to mitigate reliability needs. In this case, an economic or policy project provides benefit by helping to avoid (or delay) the need for a reliability project that would otherwise be needed.

This metric is calculated as follows:

1. Analyze thermal reliability needs in a powerflow model that includes the economic and policy projects.
2. Analyze thermal reliability needs in a powerflow model that does not include the economic and policy projects.
3. Identify any thermal reliability needs that are present only in the model without the economic and policy projects.
4. Identify projects that would mitigate each of these thermal reliability needs (avoided or delayed projects). These are identified without doing a transmission analysis that includes an N-1 thermal criteria assessment. These projects are typically identified as a new circuit or new transformer added in parallel with the overloaded element.
5. The costs of these avoided or delayed reliability projects are computed, and the benefit is set equal to the costs.

This benefit metric monetizes the reliability benefit as the avoided cost of not having to build a separate reliability project.

The benefit is allocated in accordance with the ratios of allocation that would have been applied for the costs of the reliability project.

Section 5. Mitigation of Transmission Outage Costs

5.1. History

This metric was first identified and monetized by the MTF, and subsequently included in the 2012 MTF Report.

The methodology and allocation were reviewed in 2014, with ESWG approving the use of the APC Savings methodology for the metric, and approving the use of load-ratio share to allocate the benefits. These were both consistent with what was previously approved in the 2012 MTF Report. The ESWG also approved the practice of "periodically reviewing the historical transmission outages to ensure the methodology is historically reasonable." (6/24/14)

The MOPC approved the use of the APC Savings methodology for this metric, but was unable to approve an allocation methodology for this metric. (7/15/14)

The BOD approved this metric calculation and allocation methodology "based on MOPC recommendations as augmented by the ESWG recommendations [for what was not approved by MOPC]." (7/29/14)

5.2. Description

Standard production cost simulations assume that transmission lines and facilities are available during all hours of the year and that no planned or unexpected outages of transmission facilities will occur. In practice, however, planned and unexpected transmission outages impose non-trivial additional congestion costs on the system. The benefit of reducing this additional congestion is thus not captured in the standard APC metric. The availability of new transmission projects decreases congestion and increases the operational flexibility of the system to mitigate the impacts of transmission outages.

To measure the savings due to transmission expansion during the outage of other transmission facilities, the production cost modeling analysis is augmented for a realistic level of transmission outages. Specifically, a dataset of normalized transmission outage schedules is built and, then, introduced into the production cost simulations for both the base and change cases. These normalized transmission outages are based on a historical year, with periodic updating to reflect more recent data.

The APC savings for the simulations with transmission outages can then be compared to the APC savings for the standard simulations without any transmission outages. The cost mitigation benefit of transmission upgrades during transmission outages is the difference between the APC savings with transmission outages and the APC savings without transmission outages. The benefit is computed as:

Benefit =
(Base APC with outages – Change APC with outages) – ⟵ **APC savings with outages**
(Base APC without outages – Change APC without outages) ⟵ **APC savings without outages**

Because it is difficult to develop normalized transmission outage data that reliably reflects the outages that could affect each load zone, this benefit is calculated on an SPP-wide basis and allocated to zones on a load-ratio share.

5.2.1. Example

1. Calculate base-case SPP-wide APC savings (S_B) with simulations using the transmission outage dataset

2. Calculate change-case SPP-wide APC savings (S_C) with simulations using the transmission outage dataset

3. Calculate the monetized SPP-wide benefit of mitigating transmission outage costs as the difference in APC savings considering transmission outages ($S_B - S_C$) and the standard APC savings calculated without considering transmission outages:

   $S_M = (S_B - S_C)$ less standard APC savings

4. Assume there are three zones with the following load ratio shares:
   Z_1 (load ratio share = 30%)
   Z_2 (load ratio share = 60%)
   Z_3 (load ratio share = 10%)

5. Allocate the SPP-wide transmission outage cost benefit as follows:
   Z_1 benefit=30% × S_M
   Z_2 benefit=60% × S_M
   Z_3 benefit=10% × S_M

5.2.2. Source Data

The normalized routine transmission outages are developed using a historical dataset of transmission outages for a recent year. The list of outages will include historical planned outages and a normal level of non-major forced outages. Attempts are made to select a relatively normal recent year for historical transmission outages, and avoid years that might be outliers due to extreme weather or other factors. The transmission outage dataset should avoid bias towards one zone or another.

The transmission outage dataset will be updated periodically in order to use data from a more recent year, based on the ESWG direction to "periodically review the historical transmission outages to ensure the methodology is historically reasonable." The outage statistics from the newer datasets are compared to previous datasets to help ensure that a relatively normal year of data is being utilized.

Section 6. Assumed Benefit of Mandated Reliability Projects

6.1. History

This metric was first identified and monetized by the MTF, and subsequently included in the 2012 MTF Report.

The methodology and allocation were reviewed in 2014. While the benefit calculation itself was not modified, the method for allocation of benefit was modified. Instead of allocating benefits based on the Highway/Byway allocation technique, a new hybrid allocation technique was approved by the ESWG (6/24/14) and the BOD (7/29/14).

6.2. Description

If part of the portfolio of transmission projects evaluated would be built to meet transmission reliability standards (i.e. classified as "reliability" project), then the starting point in evaluating the benefit of such reliability-projects in the evaluated portfolio would be to assume its benefit-to-cost ratio is at least 1.0. In other words, the benefit of fixing reliability violations through the reliability-portion of the evaluated portfolio should be assumed to be equal to the cost. This benefit would only be considered for projects classified as "reliability" projects.

6.2.1. Allocation of Benefit

A hybrid technique for allocation of benefits is used for this metric. The technique uses the Load Ratio Share (LRS) of the different zones, and uses a System Reconfiguration (SR) flow-based approach.

The System Reconfiguration method measures the incremental flows shifted onto the existing transmission system during an outage of the reliability upgrade being evaluated. It is a proxy for how much the reliability upgrade reduces flows on the rest of the system. Lines with increased flows after the reliability upgrade is taken out of service are identified as beneficiaries of the reliability upgrade. After removing the reliability upgrade from the powerflow model, the change in MW flow is measured for all elements in the transmission system.

Changes in flow for transmission facilities are summed by zone, based on ownership of these facilities. Joint ownership of transmission facilities is captured. Production cost modeling simulations are used to determine the hourly flow *direction* for all 8,760 hours on the reliability upgrade; "positive flow" is defined as the polarity of flow in the powerflow model. Next, the positive and negative MW relief is summed for all zones, and weighted based on 8,760 hourly flow direction. "Relief" is defined as the decrease in flow based on the addition of the reliability upgrade being evaluated; it can be positive or negative.

$$\frac{\Sigma\ hours\ with\ positive\ flow\ on\ A \rightarrow B}{8{,}760\ hours} = X\%$$

$$\frac{\Sigma\ hours\ with\ negative\ flow\ on\ A \rightarrow B}{8{,}760\ hours} = Y\%$$

$$If\ \Sigma_{Zone\,1}\ (Net\ MW\ relief\ on\ facilities) > 0:$$

$$Allocation\ Factor_{Zone\,1} = \left[\frac{\Sigma_{Zone\,1}\ (Net\ MW\ relief\ on\ facilities)}{\Sigma_{All\ zones\ with\ positive\ net\ relief}\ (Net\ MW\ relief\ on\ facilities)}\right] * X\%$$

$$If\ \Sigma_{Zone\,1}\ (Net\ MW\ relief\ on\ facilities) < 0:$$

$$Allocation\ Factor_{Zone\,1} = \left[\frac{\Sigma_{Zone\,1}\ (Net\ MW\ relief\ on\ facilities)}{\Sigma_{All\ zones\ with\ negative\ net\ relief}\ (Net\ MW\ relief\ on\ facilities)}\right] * Y\%$$

System Reconfiguration Formulas

A Highway/Byway allocation of benefits was rejected partially because it is the same allocation methodology that is being used for costs, and some felt that this was not appropriate for determining if a zone’s benefits are roughly commensurate with their costs. The System Reconfiguration methodology was developed in part because it was a flow-based approach that helped to provide a look at which zones had facilities most impacted by the reliability upgrade. While it helps to capture benefits of lower-voltage upgrades on immediately neighboring systems, it tends to result in a disproportionate allocation of benefits to nearby zones for high voltage upgrades driven by regional flows. A hybrid approach was developed and approved in which the LRS-portion of the Highway/Byway allocation is used more for higher voltage upgrades, and the SR allocation methodology is utilized more for lower voltage upgrades.

Reliability Upgrade kV	Allocation of Benefit
> 300 kV	1/3 SR, 2/3 LRS
100 - 300 kV	2/3 SR, 1/3 LRS
< 100 kV	100% SR

Approved Hybrid Benefit Allocation

6.2.2. Inclusion of Other Economic Benefits

Treating benefits for mandated reliability projects equal to their costs avoids potential undervaluing of the portfolio value of reliability projects which are mandated and thus not justified solely by other economic benefits. The question then becomes how to treat other economic (non-reliability) benefit metrics that might be associated with mandated reliability projects.

The most straightforward approach is to treat other economic benefits, such as APC Savings, that might occur from the inclusion of the mandated reliability projects in the change case as additive or subtractive. The argument favoring this approach is that NERC reliability requirements are used to justify the need for these mandated reliability projects and the resulting allocation of benefits equal to costs minimally reflects the reliability benefits to customers. Any additional APC savings (or perhaps losses) would not have occurred absent the inclusion of these mandated reliability projects, and these benefits/losses are to be considered to the reliability benefits attributed to these projects.

Another approach that was considered by the MTF is to include mandated reliability projects in the base case and thereby exclude any measure of other economic benefits associated with these projects. However, this approach could result in undervaluing the benefits of the projects. In addition, if another benefit metric shows a loss to a zone, then this approach, which would set benefits equal to allocated costs, would result in overvaluing the benefits to that zone. Thus, this approach was rejected in favor of including mandated reliability projects in the change case and adding other economic benefits to the reliability benefits equal to costs. This approach is consistent with adding the costs of avoided or delayed reliability projects.

Section 7. Marginal Energy Losses Benefits

7.1. History

This metric was originally defined in the 2012 MTF Report; however, the details of monetization had not been fully worked out, and it was not used in any studies. Further development for this metric took place in 2014 in order for it to be monetized for future studies. At this time, formulas from the 2012 MTF Report were modified in order to accurately capture losses on inter-zonal transfers. This metric and the revised formulas were approved by ESWG (6/24/14), MOPC (7/15/14), and the BOD (7/29/14) to be used in future studies.

7.2. Description

Standard production cost simulations used to estimate APC do not reflect that transmission expansions may reduce the MWh quantity of transmission losses. To simplify simulations and make run-times of the simulations manageable, load is "grossed up" for average transmission losses. The simulations then assume that the MWh quantity of losses is fixed and does not change with transmission additions. This does not capture that transmission expansion may reduce the MWh quantity of losses that need to be supplied. However, the production cost savings due to such energy loss reductions can be estimated through post-processing simulation results. This energy-cost benefit of reduced losses can be approximated by zone and by hour as follows:

$$\textbf{Loss Factor}_{\textbf{Gen,Base}} = 0.5 \times (\text{MLC}_{\text{Load, Base}} - \text{MLC}_{\text{Gen, Base}}) / \text{LMP}_{\text{Gen, Base}}$$
$$\textbf{Loss Factor}_{\textbf{Gen,Change}} = 0.5 \times (\text{MLC}_{\text{Load, Change}} - \text{MLC}_{\text{Gen, Change}}) / \text{LMP}_{\text{Gen, Change}}$$
$$\textbf{Loss Savings in MWh}_{\textbf{Gen}} = (\text{Loss Factor}_{\text{Gen,Base}} - \text{Loss Factor}_{\text{Gen,Change}}) \times \text{Gen}$$

$$\textbf{Loss Factor}_{\textbf{Imports,Base}} = 0.5 \times (\text{MLC}_{\text{Load, Base}} - \text{MLC}_{\text{Imports, Base}}) / \text{LMP}_{\text{Imports, Base}}$$
$$\textbf{Loss Factor}_{\textbf{Imports,Change}} = 0.5 \times (\text{MLC}_{\text{Load, Change}} - \text{MLC}_{\text{Imports, Change}}) / \text{LMP}_{\text{Imports, Change}}$$
$$\textbf{Loss Savings in MWh}_{\textbf{Imports}} = (\text{Loss Factor}_{\text{Imports,Base}} - \text{Loss Factor}_{\text{Imports,Change}}) \times \text{Imports}$$

$$\textbf{Loss Savings \$} = \text{MWh Loss Savings}_{\text{Gen}} \times \text{LMP}_{\text{Gen, Change}} + \text{MWh Loss Savings}_{\text{Imports}} \times \text{LMP}_{\text{Imports, Change}}$$

The Loss Savings $ are then summed for all hours of the year for each zone. The Marginal Loss Component (MLC) of the LMP is obtained from the production cost simulations. The MLC difference between gen and load or between imports and load is multiplied by 0.5 to account for the fact that average losses are half of the marginal losses. The marginal loss benefit calculations take into account the generation for the zone, as well as the imports used by each zone to serve load. MWh loss savings are multiplied by LMP price to obtain $ loss savings for each zone.

Section 8. Increased Wheeling Through and Out Revenues

8.1. History

This metric was originally defined in the 2012 MTF Report; however, the details of monetization had not been fully worked out at this time, and it was not used in any studies.

Further development for this metric took place in 2014 in order that it could be monetized for future studies. The long-term firm service portion of this metric was approved to be used in future studies, with benefit being allocated consistent with the SPP Tariff, while the non-firm transactions portion of this metric was approved to be calculated for informational purposes only. The methodology for this metric was approved by ESWG (6/24/14), MOPC (7/15/14), and the BOD (7/29/14) to be used in future studies.

8.2. Description

Increasing ATC with neighboring regions improves import and export opportunities for the SPP footprint. Increased inter-regional transmission capacity that increases through and out transactions will also increase SPP wheeling revenues. While the energy revenue benefit of increased exports is captured by the APC Savings metric (which values exports at the weighted average generation LMP of the exporting zone), the APC Savings metric does not capture any increases in wheeling out or wheeling through revenues associated with increased transfer capability. The wheeling revenues collected are not counted in either the exporting or importing region's APC. These increased wheeling revenues are a benefit as they will offset part of the transmission projects' revenue requirements. Currently, SPP collects wheeling revenues through Schedules 7, 8, and 11 for through and out transactions.

There are two complementary approaches to estimate how increased export ATCs impact wheeling service sold:

1. Identify the impact on long-term reservations based on review of long-term **firm** Transmission Service Reservations (TSRs) enabled by projects;
2. Identify the impact on **non-firm** transactions based on production cost modeling simulations.

8.2.1. Long-Term Firm TSRs

To evaluate the increased wheeling revenues based on long-term firm TSRs, a First Contingency Incremental Transfer Capacity (FCITC) analysis is conducted to determine the change in Available Transfer Capacity (ATC) for exports. Sources and sinks are defined in zones typical for TSRs.

The formulas and information shown below are based on a 2014 historical year and a 2024 study year, but different sets of years can be evaluated in the same manner.

A base case 2014 powerflow model (without transmission upgrades) and a change case 2014 powerflow model (with transmission upgrades) are evaluated for transfer limitations. In addition, the long-term wheeling service (TSRs) that SPP was able to sell as a result of those transmission upgrades is identified. A ratio is then computed for the 2014 historical year:

$$\text{Historical Ratio}_{2014} = \frac{Incremental\ Historical\ TSRs\ Sold\ Thru\ 2014\ (MW)}{ATC_{2014\ Change\ Case}(MW) - ATC_{2014\ Base\ Case}(MW)}$$

This ratio represents the historical transmission service sold per MW of increase in ATC due to previous transmission upgrades. This historical ratio is then used to forecast future long-term service that can be sold based on ATC increases from future transmission upgrades. The forecasted service sold for the 2024 study year would be calculated as:

$$\text{Forecasted Additional Service Sold}_{2024}\ (\text{MW}) =$$
$$(\text{Historical Ratio}_{2014}) \times (\text{ATC}_{2024\ \text{Change Case}}\ (\text{MW}) - \text{ATC}_{2024\ \text{Base Case}}\ (\text{MW}))$$

Note that the upgrades evaluated in the 2014 models are all included in the 2024 base <u>and</u> change case models for consistency. The one-year 2024 wheeling benefit is then calculated based on forecasted service sold and historical wheeling revenues thru 2014:

$$\text{Wheeling Benefit}_{2024}\ (\$/\text{yr}) =$$
$$\left[\frac{\textit{Incremental Wheeling Revenues Collected Thru 2014}\ \left(\frac{2024\,\$}{yr}\right)}{\textit{Incremental Historical TSRs Sold Thru 2014}\ (MW)}\right] \times \text{Forecasted Additional Service Sold}_{2024}\ (\text{MW})$$

Reduced ratios will be considered for very large future ATC increases, based on additional analysis.

Benefit for this metric is allocated consistent with the SPP Tariff. Schedule 11 revenues are allocated proportional to each zone's share of allocated costs for the NTC projects being evaluated. Schedule 7 revenues are allocated based on a zonal distribution from a recent historical snapshot, as much of these revenues are distributed in proportion to system impacts rather than in proportion to allocated costs.

<u>Example</u>

In this example, SPP sold 800 MW of incremental transmission service through 2014 based on a set of upgrades. SPP was able to collect $12M/year in wheeling revenues from this service sold (in 2014 $). These transmission upgrades provide an ATC increase from 2,000 MW to 3,600 MW in the 2014 models. The historical ratio is:

$$\frac{800\ MW\ service}{3{,}600\ MW\ ATC - 2{,}000\ MW\ ATC} = 0.5$$

The 2024 models show that a separate set of transmission upgrades being evaluated for future years show an ATC increase from 4,000 MW to 4,400 MW. The forecasted additional service sold for 2024 is:

$$0.5\ x\ (4{,}400\ MW\ ATC - 4{,}000\ MW\ ATC) = 200\ MW$$

The wheeling benefit for these future transmission upgrades is:

$$\frac{\$12M * (1 + 2.5\%\ inflation\ rate)\hat{}(10\ years)}{800\ MW\ service}\ x\ (200\ MW\ forecasted\ service) = \$3.84M$$

These upgrades are projected to generate an extra $3.84M in benefit in 2024 for the SPP region due to wheeling revenues collected for through and out transactions.

8.2.2. Non-Firm Transactions

The long-term firm service calculation will not capture the sale of non-firm hourly wheeling service that is sold based on short-term market conditions. These non-firm exports generate wheeling revenue in addition to the sale of long-term wheeling service.

In order to capture these “economy-energy” export transactions, production cost modeling simulations will utilize “hurdle rates” for market-based export transactions in order to account for a non-firm hourly service rate plus market friction. These production cost modeling tools can estimate non-firm ATC export values by adding definitions of export interfaces. Additional MW are multiplied by the SPP average rate for non-firm hourly wheeling service ($/MWh) to determine the non-firm wheeling benefit.

Wheeling revenues due to non-firm transactions are currently calculated for informational purposes only, and are not currently used to evaluate benefits of new (or existing) transmission.

Section 9. Benefit from Meeting Public Policy Goals

9.1. History

This metric was first identified and monetized by the MTF, and subsequently included in the 2012 MTF Report.

The methodology and allocation were reviewed in 2014. While the benefit calculation itself was not modified, the method for allocation of benefit was modified. Instead of allocating benefits based on each zone's share of unmet renewable requirements in the region, a new allocation technique was approved by the ESWG (6/24/14), MOPC (7/15/14), and BOD (7/29/14). This new allocation technique uses each zone's share of unmet renewable requirements only in states driving the public policy projects.

The Gerald Gentleman – Cherry County – Holt County 345 kV project was originally identified as a public policy project when it was approved as part of the 2012 ITP10. The BOD later approved a motion (7/29/14) to acknowledge that this project "provides economic and reliability benefits and not label it as a public policy project."

9.2. Description

This metric is currently limited to meeting public policy goals related to renewable energy supplies. Public policy can be met through state law, settlement agreement, or a regulatory determination made by a state regulatory authority. It does not include economic decisions made by individual utilities to acquire renewable energy supplies absent some form of legal requirement.

Note that this benefit is assessed only for projects that are classified as "policy" projects[1]. The benefit is equal to the costs of the transmission projects needed to meet public policy goals. The benefit is in achieving the goal, and the monetization of that benefit is in the cost of doing so. As with mandated reliability upgrades, the assumption is that public policy makers have made a decision that public benefit is at least equal to the cost of constructing new transmission to meet the public policy.

When a distinction is made between renewable energy mandates and goals (related to public policy) vs. an economic choice for adding renewable energy, then the cost of the transmission system required to meet the renewable energy mandates and goals must be determined separately from the transmission system required to meet total renewable energy (mandates and goals plus economic choice). Because only renewable mandates and goals are considered under public policy goals, the cost of the transmission upgrades required to meet these renewable mandates and goals would be included in setting benefits equal to costs.

The benefits are allocated only to zones subject to the renewable mandates or goals in the states that are driving the public policy projects. The benefits are allocated to those zones based on each zone's share of unmet renewable mandates or goals in those states.

[1] As of April 2015, there are no "policy" projects with NTCs – all projects are classified as either "reliability" or "economic". In this case, the Benefit from Meeting Public Policy Goals is $0.

9.2.1. Example

This example for benefit allocation includes 5 zones. A policy project is built in order to meet renewable requirements. Two of the zones (A and E) already meet their renewable policy requirements without any additional transmission upgrades; zero benefit is allocated to them. Two zones (D and E) are not subject to the renewable requirement that drove this specific policy project; zero benefit is allocated to them.

The remaining two zones (B and C) receive the benefit allocation based on their share of unmet renewable requirements.

Zone B receives 800/(800 + 1,800) = 30.8% of the benefit

Zone C receives 1,800/(800 + 1,800) = 69.2% of the benefit

These allocation factors are then multiplied by the total Benefit from Meeting Public Policy Goals (benefits equal to costs) to determine the benefit dollars by zone.

Zone	Renewable Requirement (GWh)	Renewable Requirement Met Without Upgrades (GWh)	Unmet Share of Renewable Requirement (GWh)	Subject to Renewable Requirement Driving the Policy Project?	Benefit Allocation
A	1,000	1,000	0	Yes	0.0%
B	1,500	700	800	Yes	30.8%
C	3,000	1,200	1,800	Yes	69.2%
D	1,500	300	1,200	No	0.0%
E	0	0	0	No	0.0%

9.2.2. Inclusion of Other Economic Benefits

In regard to other economic benefits, the Benefit from Meeting Public Policy Goals is treated identical to the Assumed Benefit from Mandated Reliability Projects in that these other benefits, such as APC Savings, are treated as additive or subtractive to the Benefit from Meeting Public Policy Goals.

Section 10. Calculation of 40-Year Benefits

The ITP Process shall assess the cost effectiveness of the final consolidated portfolios over a forty-year time horizon in accordance with Section III.3.c of Attachment O of the SPP OATT. Benefits and costs of new upgrades are computed for a 40-year timeframe, to evaluate all benefits and costs over the full lifetime of the transmission upgrade.

~~Transmission upgrades have a typical life span of approximately 40 years. As a result, benefits and costs of new upgrades are computed for a 40-year timeframe, to evaluate all benefits and costs over the full lifetime of the transmission upgrade.~~

The following benefit metrics have benefit set equal to transmission costs over the 40 years:

- Avoided or Delayed Reliability Projects
- Assumed Benefit of Mandated Reliability Projects
- Benefit from Meeting Public Policy Goals

The other metrics, as described below, use interpolation, extrapolation, and a terminal value for computing benefits over 40 years:

- APC Savings
- Mitigation of Transmission Outage Costs
- Reduced Capacity Costs Due to Reduced Transmission Losses on Peak
- Increased Wheeling Through and Out Revenues
- Marginal Energy Losses

In order to ~~compute~~ estimate 40 years of benefit for each these metrics, 2-3 data points representing one-year benefits are computed, using powerflow or production cost simulation tools. At a minimum, years 5 and 10 will be used as data points.

- The benefits for each year in between the 2-3 study years are computed by interpolating between the 2-3 data points.
- The benefits for ~~each year within the first 20 years~~up to 5 years that are outside the range of the 2-3 study years are computed by extrapolating values outside of the 2-3 study years based on the slope or trend of the 2-3 data points.
- The benefits for the remaining years through year 40 ~~years 21-40~~ are computed using a terminal value. An inflation rate (typically assumed to be 2.5%) is used to determine benefits for each of these years.
- After benefit is evaluated for each of the 40 years, the 40-year Net Present Value (NPV) of benefit is then computed using a discount rate (typically assumed to be 8%) to bring each year's dollars back to the first year.
  - If the first year of benefits is ~~2019~~Year 5, ~~and the current year is 2015,~~ the 40-year NPV benefits are brought from ~~2019~~ Year 5 dollars to ~~2015~~ current dollars using a 2.5% inflation rate.

The project costs will be calculated using the formulas for Annual Transmission Revenue Requirement (ATRR). The total benefits and costs will be reported in net present value (NPV) dollars.

Benefit and impact calculations will be made on a Regional, Zonal, and State basis. Many zones are only in one state. For those zones that are only in one state, their full portion of both costs and benefits will be allocated to the state. For zones crossing state borders, their portion of both costs and benefits will be allocated to each state based on their percentage of load that is in each state.

Net benefits and B/C ratios will be calculated based on NPV benefit and NPV cost and will be reported based on current dollars.

10.1. Example

Here is an example of the 40-year calculation of benefits for one of the metrics listed above in which there are 3 data points.

- The current year is assumed to be 2014, meaning we want to evaluate benefit in 2014 dollars.
- The transmission upgrades being evaluated go into service in 2016.
- Production cost modeling simulations show one-year benefits of $30M in 2018, $110M in 2023, and $190M in 2028.

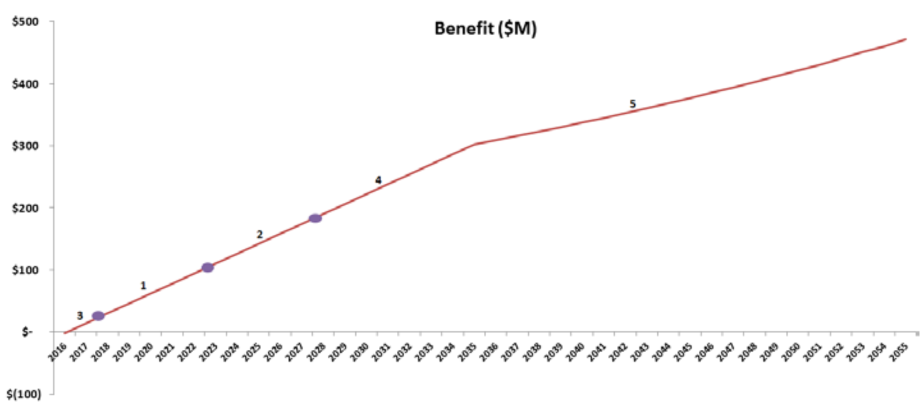
Based on these inputs, here is step-by-step calculation of the 40-year benefits:

1. Benefits for years 2019 – 2022 are computed by interpolating between the 2018 and 2023 data points – if a straight line is drawn between the 2018 and 2023 data points, the benefit for each year in the 2019 – 2022 range will lie along that line.
2. Benefits for years 2024 – 2027 are computed by interpolating between the 2023 and 2028 data points – if a straight line is drawn between the 2023 and 2028 data points, the benefit for each year in the 2024 – 2027 range will lie along that line.
3. Benefits for years 2016-2017 are computed by extrapolating backwards from the 2018 data point. The slope of the line from the 2018, 2023, and 2028 data points will be used to extrapolate benefits for 2016-2017. If the 3 data points do not lie along the same line, a "trending" function will be used to determine an approximate slope based on the 3 data points.
4. Benefits for years 2029-2035 are computed by extrapolating forward from the 2028 data point. The slope of the line from the 2018, 2023, and 2028 data points will be used to extrapolate benefits for 2029-2035. If the 3 data points do not lie along the same line, a "trending" function will be used to determine an approximate slope based on the 3 data points.
5. Benefits for years 2036 – 2055 are computed by using the inflation rate (typically 2.5%) based on the previous year's benefit.

   Here is the resulting one-year benefit for each year:

	Year	Benefit ($M)
1	2016	($2)
2	2017	$14
3	2018	$30
4	2019	$46
5	2020	$62
6	2021	$78

7	2022	$94
8	2023	$110
9	2024	$126
10	2025	$142
11	2026	$158
12	2027	$174
13	2028	$190
14	2029	$206
15	2030	$222
16	2031	$238
17	2032	$254
18	2033	$270
19	2034	$286
20	2035	$302
21	2036	$309
22	2037	$316
23	2038	$323
24	2039	$330
25	2040	$338
26	2041	$345
27	2042	$353
28	2043	$361
29	2044	$369
30	2045	$377
31	2046	$386
32	2047	$394
33	2048	$403
34	2049	$412
35	2050	$422
36	2051	$431
37	2052	$441
38	2053	$451
39	2054	$461
40	2055	$471



Example Benefit in Nominal Dollars

6. The benefit for each year is discounted back to 2016 $ using the discount rate (typically 8%) in order to calculate the 40-year NPV benefit. This is performed using the formula:

$$\mathbf{40-Yr\ NPV\ Benefit\ (2016\ \$)} = \frac{\mathbf{Year\ 1\ Benefit}}{\mathbf{1}} + \frac{\mathbf{Year\ 2\ Benefit}}{\mathbf{1.08}} + \frac{\mathbf{Year\ 3\ Benefit}}{\mathbf{1.08^{\wedge}2}} + \frac{\mathbf{Year\ 4\ Benefit}}{\mathbf{1.08^{\wedge}3}} + \cdots \ldots\ldots$$

   The 40-year NPV benefit (2016 $) in this example is **$2.000B**.

7. The 40-year NPV benefit in real dollars (2014 $ in this case) is computed by using the inflation rate (typically 2.5%) to take the 40-year NPV benefit in 2016 $ to 40-year NPV benefit in 2014 $.

   The 40-year NPV benefit (2014 $) in this example is **$1.904B**.

   This is reported as the 40-year benefit. This method would apply to any of the following metrics: APC Savings, Mitigation of Transmission Outage Costs, Reduced Capacity Costs Due to Reduced Transmission Losses on Peak, Increased Wheeling Through and Out Revenues, or Marginal Energy Losses.

Southwest Power Pool

Southwest Power Pool

JOINT TRANSMISSION & ECONOMIC STUDIES WORKING GROUP MEETING

February 15, 2017

Embassy Suites Riverwalk – San Antonio, TX

• M I N U T E S •

Agenda Item 1 – Administrative Items

Call to Order, Introductions

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

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

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

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

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

Receipt of Proxies
Kirk identified the following proxies:

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

Kelsey identified no proxies.

Agenda Item 2 – Consent Agenda

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

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

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

Agenda Item 3 – ITP Manual Task Force Update

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

Agenda Item 4 – Lubbock Exit Study

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

Agenda Item 5 – ITP Scope Standardization

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

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

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

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

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

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

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

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

Agenda Item 6 – 2017 ITP10 Update

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

Respectfully Submitted,

Kirk Hall
TWG Secretary

Kelsey Allen
ESWG Secretary

Southwest Power Pool

JOINT TRANSMISSION/ECONOMIC STUDIES WORKING GROUP MEETING

April 3, 2017

Net Conference – Little Rock, AR

• Summary of Action Items •

1. Approved removal of Potter – Tolk 345 kV line from the 2017 ITP10
2. Approved the 2017 ITPNT Report and Portfolio
3. Approved the 2018 ITPNT Scope

Southwest Power Pool

JOINT TRANSMISSION/ECONOMIC STUDIES WORKING GROUP MEETING

April 3, 2017

Net Conference – Little Rock, AR

• 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 9:05 am. The following members were in attendance (Attachment 1a – Attendance) or represented by proxy (Attachment 1b – Proxies):

TWG
Travis Hyde (Chair), Oklahoma Gas & Electric
Daniel Benedict, City of Independence
Scott Benson, Lincoln Electric System
John Boshears, City Utilities of Springfield
Richard Dahl, Missouri River Energy Services
John Fulton, Southwestern Public Service Company
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
Nathan McNeil, Westar Energy, Inc.
Alan Myers, ITC Great Plains
John Payne, Kansas Electric Power Cooperative
Jason Shook, GDS Associates representing ETEC
Matthew Stoltz, Basin Electric Power Cooperative
Noman Williams, South Central MCN
Brian Wilson, Kansas City Power & Light

ESWG
Alan Myers, ITC Great Plains
Randy Collier, City Utilities of Springfield
Natasha Henderson, Golden Spread Electric Cooperative
Pat McCool, Kansas City Power & Light
Leon Howell, Oklahoma Gas & Electric
John Iverson, Omaha Public Power District
Bethany King, Empire District Electric
Tim Owens, Nebraska Public Power District
Jeremy Severson, Basin Electric Power Cooperative
Kurt Stradley, Lincoln Electric System
Michael Watt, Oklahoma Municipal Power Authority
Bennie Weeks, Southwestern Public Service Company/Xcel
Ryan Yokley, Sunflower Electric Power Cooperative

Kirk Hall and Kelsey Allen informed the Chairs of each group had a quorum.

Kirk identified the following proxies:

- Brian Wilson (KCP&L) proxy for Harold Wyble (KCP&L)

Kelsey identified the following proxies:

- Ryan Yokley (SUNC) proxy for Al Tamimi (SUNC)

Agenda Item 2 – Potter-Tolk 345 kV Additional Analysis

Juliano Freitas, SPP staff, presented the analysis approach, results, and staff recommendation for the Potter-Tolk 345 kV continued evaluation (Attachment 2 – Potter-Tolk 345 kV) as part of the 2017 ITP10. Clarifying questions related to model changes, updates to the cost estimate, and benefit metric calculation were asked by the stakeholders. Because of the uncertainty with the range of analysis completed, staff made a recommendation to remove the project from the 2017 ITP10 portfolio.

> **Motion: John Fulton made a motion to accept staff's recommendation to remove the Potter-Tolk 345 kV line from the 2017 ITP10 portfolio. Dan Lenihan seconded the motion. The motion was passed with two abstentions from Noman Williams (South Central MCN) and Alan Myers (ITC Great Plains).**

> **Motion: Bennie Weeks made a motion to accept staff's recommendation to remove the Potter-Tolk 345 kV line from the 2017 ITP10 portfolio. Leon Howell seconded the motion. The motion was passed with one abstention from Alan Myers (ITC Great Plains).**

**At the conclusion of Agenda Item 2, the joint session with the ESWG concluded and the TWG continued with the additional agenda topics.*

Agenda Item 3 – 2017 ITPNT Report and Portfolio

Dee Edmondson, SPP staff, presented the 2017 ITPNT Report and Portfolio (Attachment 3a, 3b – 2017 ITPNT Final Portfolio Presentation, 2017 ITPNT Final Report). She reviewed the final portfolio recommendations as well as the report language. The TWG asked for one correction to be made to the report on a map.

> **Motion: Jason Shook made a motion to accept staff's recommendations on the 2017 ITPNT. Daniel Benedict seconded the motion, which passed unanimously.**

Agenda Item 4 – 2018 ITPNT Scope

Kirk presented the scope for the 2018 ITPNT Assessment (Attachment 4 – 2018 ITPNT Scope). He pointed out a modification to DC tie dispatch methodology in the Nebraska and IS areas biasing the ties in the same direction as well as adding a sensitivity case to bias them in the opposite direction. TWG members affected by these DC ties voiced support to this modification, which would lead to analysis that ensured previously approved long term firm transmission service would be protected.

> **Motion: Alan Myers made a motion to approve the 2018 ITPNT Scope as modified during the meeting. Jason Shook seconded the motion. The motion passed with no opposition.**

The meeting was adjourned at 11:36 am.

Respectfully Submitted,

Kirk Hall
TWG Secretary

Kelsey Allen
ESWG Secretary

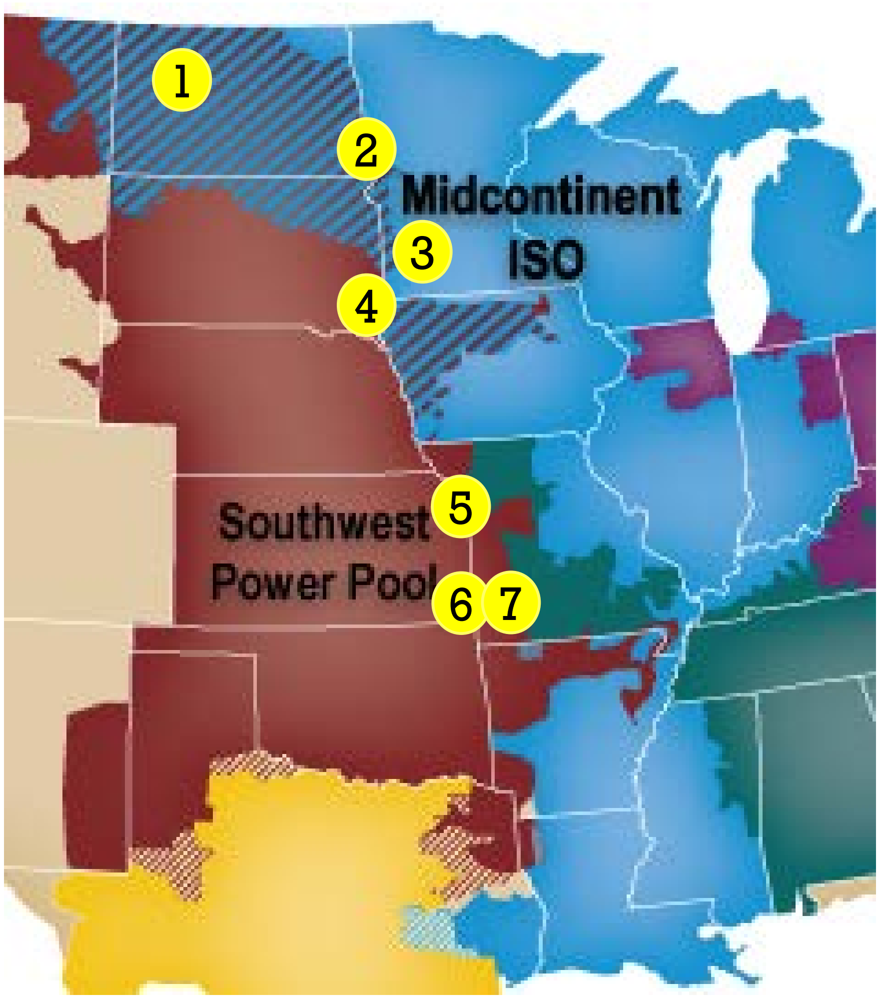
SPP-MISO CSP Recap and Regional Review

May 17,2017

Adam Bell & Clayton Mayfield

2016 SPP-MISO CSP Recap

MISO – SPP 2016 CSP Study



NEED	CONSTRAINT	LOCATION
1	Rugby WAUE-Rugby OTP Tie FLO Rugby – Balta 230 kV	SPP-MISO Tie Line
2	Hankinson - Wahpeton 230kV FLO Jamestown - Buffalo 345kV	MISO
3	Sub3 - Granite Falls 115kV Ckt1 FLO Lyon Co. 345/115 kV transformer	SPP-MISO Tie Line
4	Sioux Falls - Lawrence 115kV FLO Sioux Falls - Split Rock 230kV	SPP-MISO Tie Line
5	Northeast - Charlotte 161kV FLO Northeast - Grand Ave West 161kV	SPP
6	Neosho - Riverton 161kV FLO Neosho - Blackberry 345kV	SPP
7	Brookline 345/161kV Ckt 1 Transformer FLO Brookline 345/161kV Ckt 2 Transformer	SPP

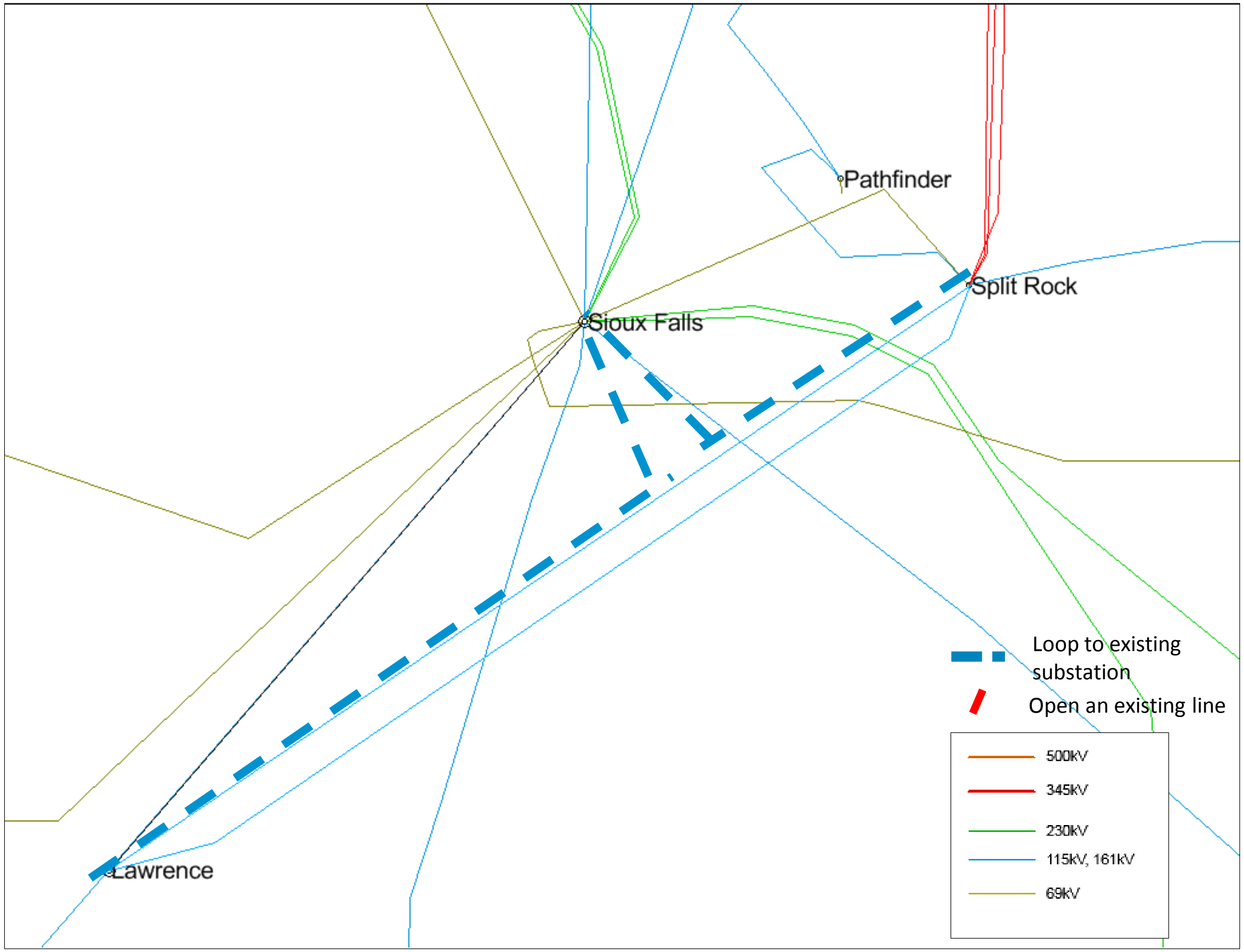
Potential Interregional Projects

Need Addressed	Project Description
2	Rebuild Hankinson - Wahpeton 230kV line
3	2nd Lyon County Transformer
4	Loop One Split Rock - Lawrence 115kV Ckt into Sioux Falls
5	Northeast - Charlotte 2 ohm series reactor
5	Crosstown - Blue Valley 161 kV line
6	Lacygne - Blackberry 345 kV line plus 345/161 kV transformer and Blackberry - Asbury 161 kV line
7	James River - Brookine 345 kV line plus 345/161 kV transformer
7	Morgan 345/161 kV Transformer plus Morgan - Brookline 161 kV uprate

- No beneficial projects were identified for Need 1
  - Rugby WAUE-Rugby OTP Tie (Need #1)
    - Model update reduced congestion in the joint model to lower levels than were experienced in the regional models

SPP

I-18: Loop One Split Rock-Lawrence 115 kV ckt into Sioux Falls



- **Project Details** –
  - Location: South Dakota
  - Loop One Split Rock - Lawrence 115kV Ckt into Sioux Falls
  - **Congestion Analysis** – Completely relieves congestion on Lawrence – Sioux Falls 115 kV
- **E&C Cost: $5.2M***
- **20-Yr B/C: 4.42***
  - SPP Benefit: 18.52%
  - MISO Benefit: 81.48 %

*Scoping level cost estimate (pending)

I-18: Loop One Split Rock-Lawrence 115 kV ckt into Sioux Falls cont.

- Project meets JOA criteria
  - 81.48% Benefit to MISO (% of cost allocated to MISO)
  - 18.52% Benefit to SPP (% of cost allocated to SPP)
- Joint analysis shows substantial benefit
  - 4.42 B/C Ratio
  - $27.83M NPV Project Benefit
- Completely relieves congestion from Need #4
- **SPP and MISO staff recommend the approval of this project from the CSP into the SPP and MISO regional review processes**
- **SPP and MISO portions of the IPSAC endorsed staff recommendations**

SPP

Regional Review

Purpose

- Regional evaluation of a recommended seams project
  - Evaluates a seams or interregional project using SPP developed assumptions and analyses
  - Allows SPP stakeholder review through the applicable stakeholder groups
  - Provides an approval process
- Stakeholder evaluation process
  - Verify benefits and costs of projects are appropriate for SPP
- Opportunity for SPP Board of Directors review and approval of projects

Process

- Attachment O, Section IV, Subsection 6
  - The Transmission Provider shall facilitate a **regional review of the proposed Interregional Projects identified in the Coordinated System Plan** (“CSP”) report developed and issued pursuant to the applicable Interregional Planning Process. The regional review will be subject to the timelines identified in the respective Interregional Planning Region procedures in accordance with the applicable Addendum(s) to this Attachment O.
  - The Transmission Provider shall, in consultation with stakeholders, develop the **Regional Review Methodology** which shall be posted on the Transmission Provider’s website.
- Required by the SPP-MISO JOA to be completed in 6 months

SPP

Process Cont.

- **Regional Review Methodology**
  - Approved by ESWG, TWG, and MOPC
    - 2013/2014
  - Outlines the process and provides guidance on the regional review
  - ESWG responsible for the review of Economic Projects
  - Link to Regional Review Methodology Document

SPP

Regional Review of Projects Addressing Economic Needs

- Criteria
  - B/C requirement of 1.0
  - Benefit metrics used at a minimum must include APC
- Analysis
  - minimum a security constrained unit commitment /security constrained economic dispatch analysis will be utilized for the calculation of APC
- Study Assumptions
  - Model(s) and assumptions used will be based on the most recent ITP10 unless otherwise directed by the ESWG
- Model Development
  - Updates to model necessary to reasonably evaluate the project may be made on top of the already existing model

Stakeholder Process

- ESWG and the SSC are the primary stakeholder groups that will direct the regional review
- ESWG will be responsible for approving the analysis to be completed
- ESWG and the SSC will be asked to make a recommendation to the MOPC on approval of the project
- MOPC will determine whether or not to recommend approval of the joint project to the SPP Board
- SPP Board will have final approval on the project

SPP

2017 SPP-MISO CSP Regional Review

SPP-MISO CSP Model Overview

- Utilized SPP's 2017 ITP10 F1 models
  - Built a 2030 model for 20-year benefit curve
- Model Updates
  - Notifications to Construct (NTC):
    - 2016 ITPNT
    - Generation Interconnection
    - Transmission Service Studies
  - Model Corrections:
    - 2016 ITPNT
    - 2017 ITP10
    - Wind Hourly Profile Update
    - Fort Calhoun Retirement
  - SPP owned windfarm curtailment price set to $0.50
  - Percent ownership update for jointly-owned units

SPP

SPP-MISO CSP Model Overview Cont.

- SPP 2030 PROMOD Model
  - Utilized 2030 Load growth from 2017 ITP10 Load review
  - Used 30% of 2030 load for wind additions
  - Used 7% of 2030 load for solar additions
  - Conventional units added to obtain 12% capacity margin
  - Utilized existing sites and new sites
    - New sites followed 2017 ITP10 priority:
      - Existing 2025 sites
      - 2035 RCAR sites
      - 2017 ITP10 sites by ranking

SPP-MISO CSP Model Overview Cont.

- MISO CPP PROMOD Model
  - Utilized MISO's MTEP16 Regional CPP Model
    - Base for all models
  - MTEP16 Updates:
    - Retirement Updates
    - MCPS16 Projects
    - Percent ownership update for jointly-owned units
    - Incorporation of a Generation Interconnection Project

SPP-MISO CSP Model Overview Cont.

- Powerflow
  - SPP Staff merged MISO and SPP CPP powerflow models
    - MISO MTEP16 powerflow used as base
  - Utilized latest MMWG for Tie Line differences
  - PROMOD 2030 model utilized the 2025 powerflow model
    - SPP and MISO had no NTC's past 2025

2017 Regional Review Proposed Model

Model Option One

- Utilize the 2016 SPP MISO CSP PROMOD and Powerflow models
- Benefits of CSP model:
  - Wind capacity more realistic
  - Already includes majority of model corrections that will need to be made (Sidebar updates)
  - Third data point for benefit numbers if needed
  - Utilizes METP16 regional resource plan which removed the 1000MW of wind resource units impacting the Regional Review Project and Need that caused ITP to not recommend an NTC
- Staff recommended updates:
  - 2017 ITP10 NTCs
  - 2017 ITPNT NTCs and model corrections
  - Regional Review Stakeholder submitted model corrections
  - "Additive" Peak and Off-Peak only Constraint Assessment to assess impacts of NTCs and ITPNT model corrections

SPP

Model Option Two

- Utilize the 2017 ITP10 F1 PROMOD and Powerflow models
- Benefits of ITP model:
  - Stakeholders are more familiar with model
- Cons of using ITP model:
  - Will require significant updates to powerflow and PROMOD models
  - Utilizes MISO Sub-regional CPP resource plan that significantly impacts the Regional Review Project and Need
- Staff recommended updates:
  - 2016 ITPNT NTCs and model corrections
  - 2017 ITP10 NTCs and model corrections
  - 2017 ITPNT NTCs and model corrections
  - Wind Hourly Profile Update
  - Fort Calhoun Retirement
  - Regional Review Stakeholder submitted model corrections
  - "Additive" Peak and Off-Peak only Constraint Assessment to assess impacts model updates

Stakeholder Updates

- 6 month process reduces types of model changes that can be made
  - October MOPC/BOD leaves 4 months available for work
- Recommended Stakeholder updates:
  - Unit retirements
  - Load Updates
  - Topology Updates

Staff Recommendation

SPP Staff recommends that the ESWG approve to use the 2016 SPP MISO CSP PROMOD and Powerflow models as the base models

Motion:

Conduct the 2017 Regional Review utilizing the 2017 ITP10 Future 1 and Future 3 2025 sidebar model to calculate a 1-year B/C ratio on the approved Interregional Project

2017 Regional Review Proposed Metrics

Proposed Benefit Metrics

- Staff recommends using the following ITP metrics
  - Adjusted Production Cost
  - Mitigation of Transmission Outage Costs

Staff Recommendation

SPP Staff recommends that the ESWG approve to use Staff proposed Benefit Metrics.

Staff/Stakeholder Accountability

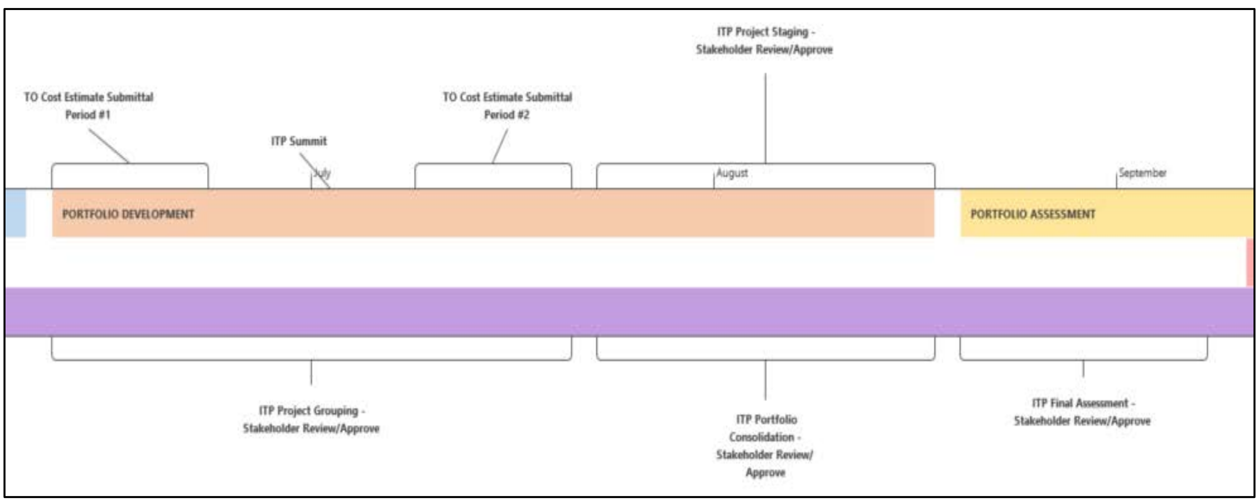
SPP Stakeholders and Staff will introduce steps to focus on accountability for timelines and milestones that consist of mechanisms designed to promote the timely exchanges of data, reviews, and approvals within the transmission planning process.

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. Staff will coordinate with Stakeholders in the development of this schedule and formally vet the final schedule with Stakeholders upon the completion of the study scope.

This schedule will be maintained by SPP Staff and regularly reviewed at appropriate stakeholder meetings to keep affected parties informed of upcoming milestones to assist with 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



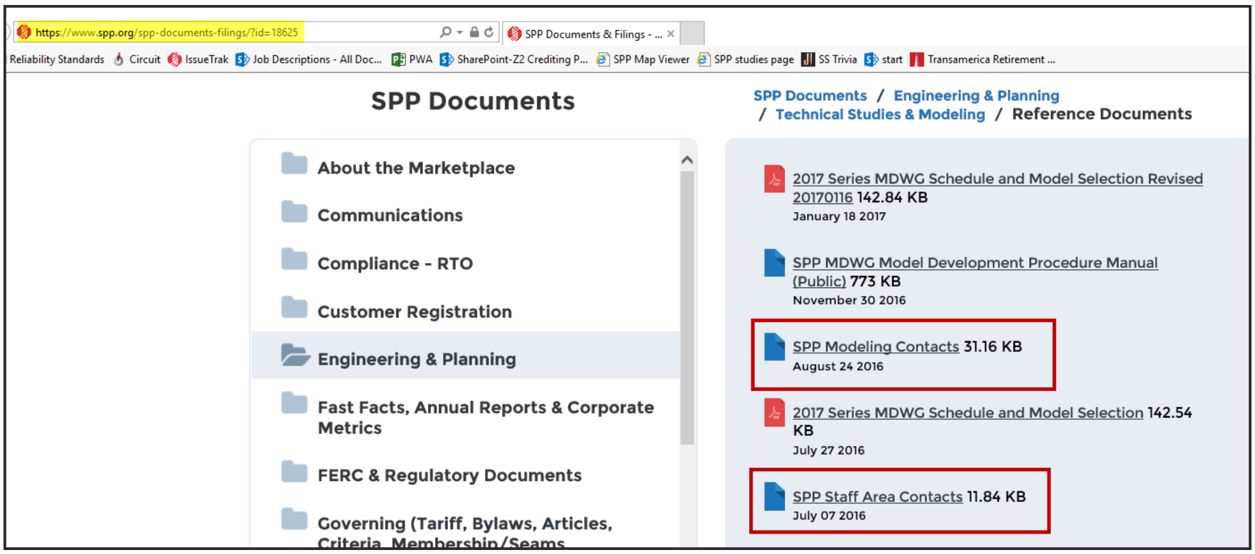
Point of Contact

Clear and timely two-way communication between SPP Staff and Stakeholders is vital to the successful completion of the annual study process. TPITF discussions centered on the use of a central point of contact (CPOC) to help increase the coordination and timely delivery of ~~required~~ information necessary to meet scheduled milestones. This information can range from modeling data submittals to a request to push information to Stakeholder MOPC representatives for upcoming MOPC approvals.

Stakeholders may choose how they address the CPOC for their respective companies. Potential options may include:

- Identifying a specific person who will coordinate the various requests that come out of the planning process.
- Assign individuals that will be responsible for specific parts of the planning process. For example, ~~Each member company will~~ identify a ~~central point of contact (~~CPOC~~)~~ ~~for their company~~ who will be responsible for coordinating the submission of all data required to support the modeling and planning processes. Another contact may be responsible for project review and cost estimate submittals.
- Provide SPP Staff with an email address that can be used for requests that will target specific groups with their organization instead of pointing directly to 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.~~TPITF discussions centered on the use of a CPOC to help increase the coordination and timely delivery of required information necessary to meet scheduled milestones.~~

The SPP Modeling department currently lists Modeling and Staff Area contacts on SPP's corporate website (below). SPP Staff CPOCs for the ITP study process will be determined during the development of the study scope and published on the *Transmission Planning* page of the website. The list of Stakeholder CPOCs will be maintained internally by Staff.



Data Submission, Reviews/Approvals, and Mitigation

Applicable SPP working groups and 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, it is a process expectation that data reviews and required approvals will be conducted by the associated schedule deadlines. The failure ~~of a Stakeholder~~ to properly and timely perform the required review should not cause a delay in the corresponding process. In the event ~~that~~ review deadlines are missed, the items requiring review or approval will be ~~assumed to be appropriate~~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 wants to add or change data used in the study process may make a request for consideration of the proposed data to SPP Staff. Staff will assess the proposed data to determine if the request will have a material impact on study results. For requests that do not impact the planning process or results, the data will be included by Staff or the study process will continues as-is. For requests that will have an impact on the study process or results and subsequently an impact to the study schedule, the submitting Stakeholder will be informed of the potential impact(s) and a waiver request will be required to alter the study schedule. The waiver process is described below. ~~a waiver of the deadline to the MOPC.~~

SPP Staff may also request a deadline waiver if a process issue causes a need to revisit a schedule deadline due to the impact of the issue on the study results. Staff will assess the issue and provide feedback to the appropriate working group(s) for consideration for a waiver. Upon a working group recommendation, Staff may move forward with a waiver request. The waiver process is described below.

A Stakeholder or SPP Staff may solicit the MOPC for a delay in the completion of a schedule milestone. The waiver request should include background information on the issue and the rational for requesting the delay. In support of the waiver process, SPP Staff will provide the MOPC with the project schedule impacts, schedule mitigation plans, and an estimate of any costs associated with accommodating the waiver to support the MOPC decision--making process. The approval of the MOPC will be required to make any adjustments to the process schedule or incur additional financial costs associated with process mitigation.

With the MOPC's quarterly meeting schedule and the need for a more immediate resolution of a waiver request, the 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.

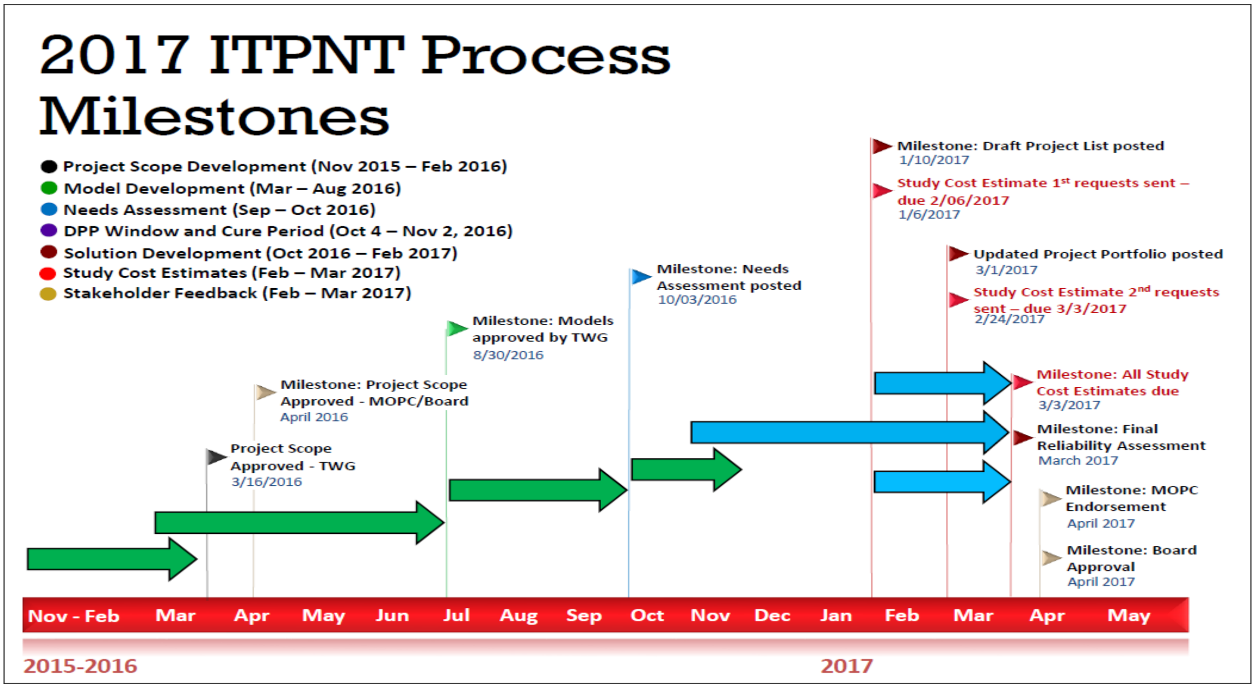
~~*There has been discussion about Staff performing their own impact assessment to determine if the lack of data or action would be material to the process. Using engineering judgement, Staff would make this determine and share it with the stakeholder and/or appropriate working group. For data, Staff may look to set parameters around what might be considered material. For instance +/- 1.5% on load growth. If a stakeholder has a late load growth submission of 1%, it would automatically be disqualified and passed into the next model build. If the load growth comes in at 2% (outside of bandwidth), staff would use judgement to determine the impact. For example, if it's in northwest North Dakota, there may not be an impact like it would be if it was the OK city area.*~~

~~*This level of detail would not be included in the document, rather under the corresponding item in the Standardized Scope.*~~

MOPC Report

SPP Staff will provide a quarterly report to the MOPC highlighting the process 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 Stakeholders and Staff will inform MOPC of the attention and importance placed on the successful completion of milestones and adherence to deadlines critical to producing a complete, high-quality, and timely report and portfolio. Issues requiring mitigation, as mentioned above, whether through the actions of Staff or Stakeholders will be presented in sufficient detail to give the 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)
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: Needs Assessment posted
10/03/2016
Milestone: Models approved by TWG
8/30/2016
Milestone: Project Scope Approved - MOPC/Board
April 2016
Project Scope Approved - TWG
3/16/2016
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
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2015-2016
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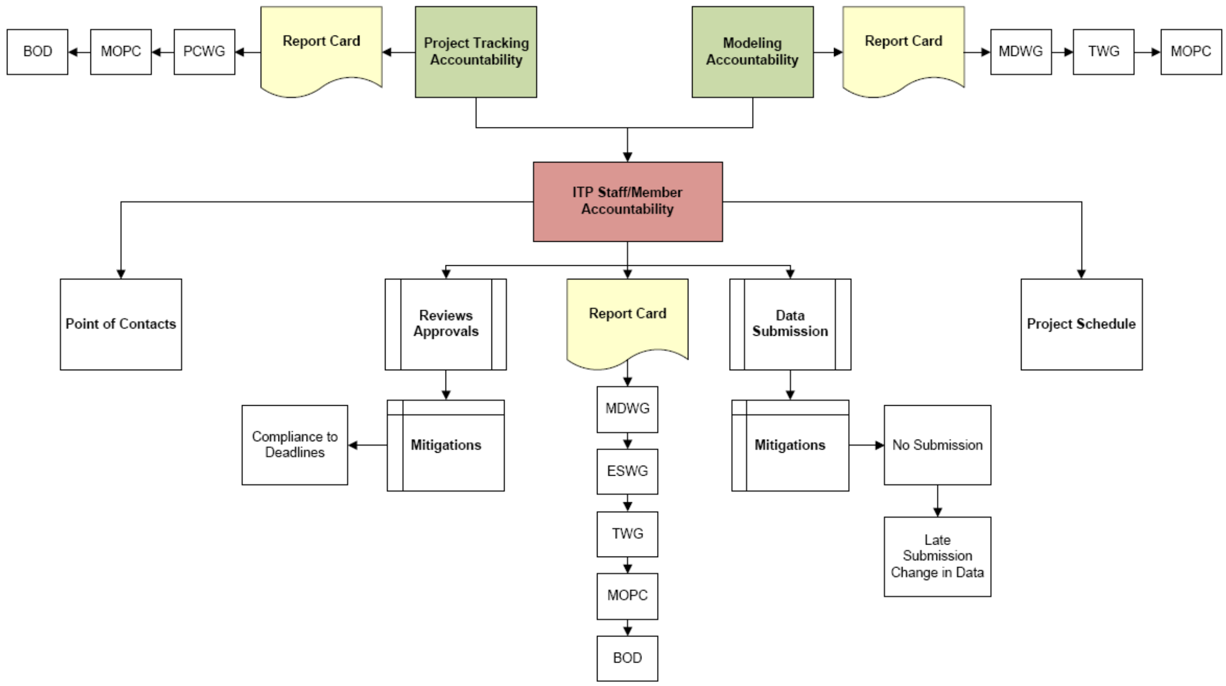
BOD
MOPC
PCWG
Report Card
Project Tracking Accountability
Modeling Accountability
Report Card
MDWG
TWG
MOPC
ITP Staff/Member Accountability
Point of Contacts
Reviews Approvals
Report Card
Data Submission
Project Schedule
Compliance to Deadlines
Mitigations
MDWG
ESWG
TWG
MOPC
BOD
Mitigations
No Submission
Late Submission Change in Data


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Economic Project Screening and Portfolio Development

May 17,2017

Project Screening

Project Screening Criteria

- SPP-derived conceptual estimates will be used for screening
- For a project to be eligible for an economic grouping, it must meet one of the following:
  - 1-year individual project B/C threshold
    - Project performance will be assessed for each future and year
    - ≥ 0.5 to pass screening
    - SPP average NPCC percentage at the time of project screening will be used
  - 40-year NPV individual project B/C threshold
    - Projects performance will be assessed for each future
    - NPV year will be the ITP study completion year
    - SPP average NPCC percentage at the time of project screening will be used for NPV cost
    - All projects will assume the 5 year model year as ISD
    - ≥ 1.0 to pass screening

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Project Screening Criteria

- If at least one of the following is true for a project, it will be flagged for Seams potential
  - Interconnects to a non-SPP TO
  - APC benefit to a neighbor is at least 20% of total benefit of SPP and neighbor
- Apply a minimum of 20% cost sharing ratio to neighboring region for Seams projects

SPP

ITP Groups

ITP Groups

- Cost-Effective*
  - Total project cost / total flowgate congestion cost relief
  - Project selection based on each economic need
    - Avoids the issue of determining which flowgates should be included or excluded from the total congestion cost relief
- Highest net APC benefit*
  - APC Benefit – Project Cost
  - Project selection based on SPP net APC benefit
    - Avoids the issue of potentially excluding candidate projects that may have minor relief on multiple flowgates
- Multi-Variable*
  - Allow Staff to layer projects from other two groupings or additional analysis to develop portfolio

* The final portfolio for each future will be selected by SPP Staff considering SPP Stakeholder feedback

SPP

Portfolio Development

Project Ranking and Project Considerations

- Create a ranked list of best performing projects by Need or set of Needs for each group by year
- Project Selection Considerations:
  - 1-year project cost, APC benefit, B/C ratio
  - 40-year NPV cost, APC benefit, and B/C ratio
  - The congestion relief that a project provides for the economic needs of that Future and year
  - Project overlap – two projects that relieve the same congestion are not both included in a portfolio
  - The potential for a project to mitigate multiple economic needs
  - Any potential routing or environmental concerns with projects
  - Any long-term concerns about the viability of projects

SPP

Project Ranking and Project Considerations Con't

- Project Selection Considerations Con't:
  - Individual project robustness, which includes but is not limited to event file modification
  - The potential for a project to mitigate reliability and operational needs, which covers current market congestion
  - The potential for a project to address non-thermal issues
  - The need for new infrastructure versus leveraging existing infrastructure
  - Consideration of larger-scale solutions that provide more robustness and multiple values

SPP

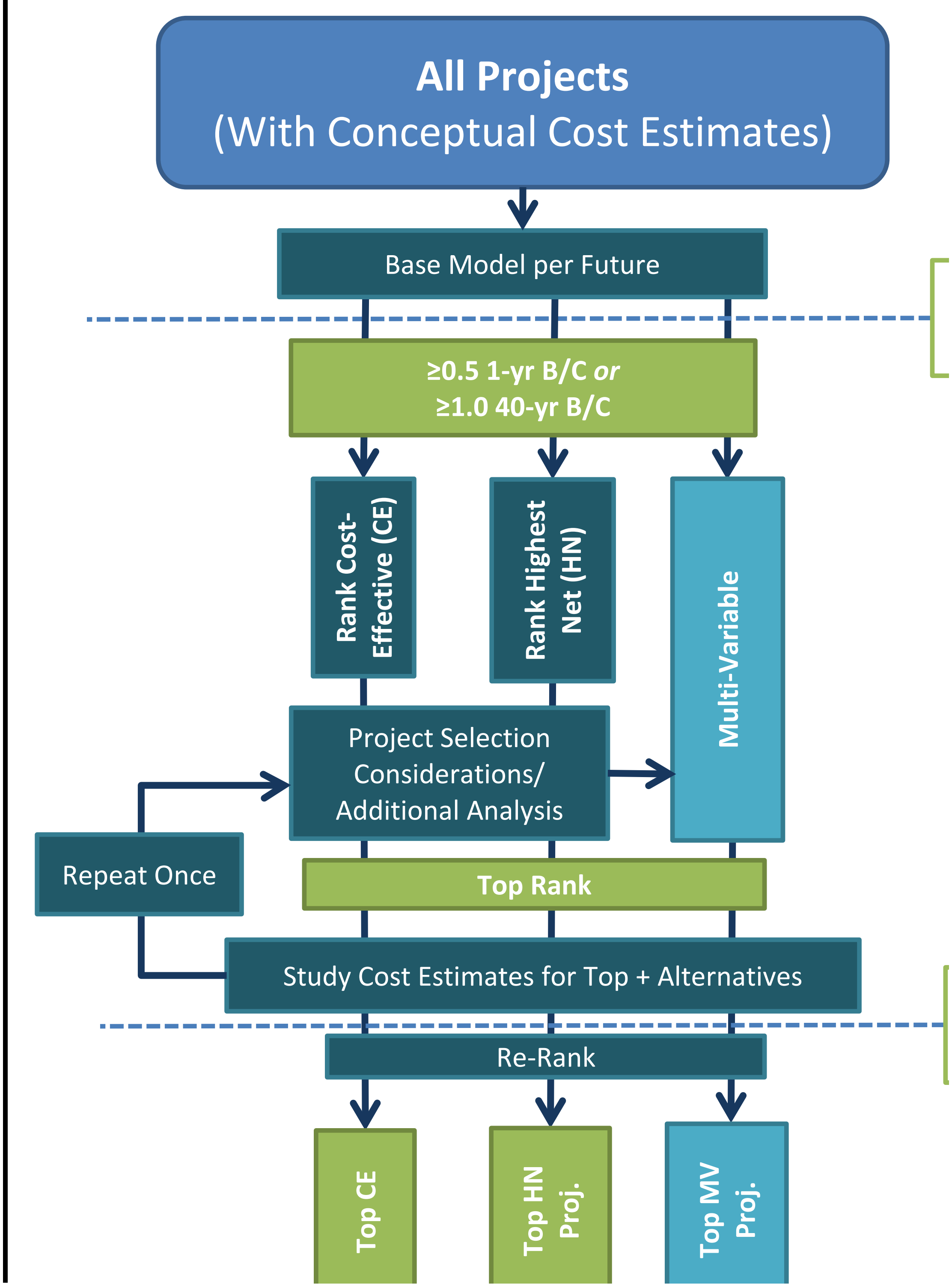
Portfolio Determination

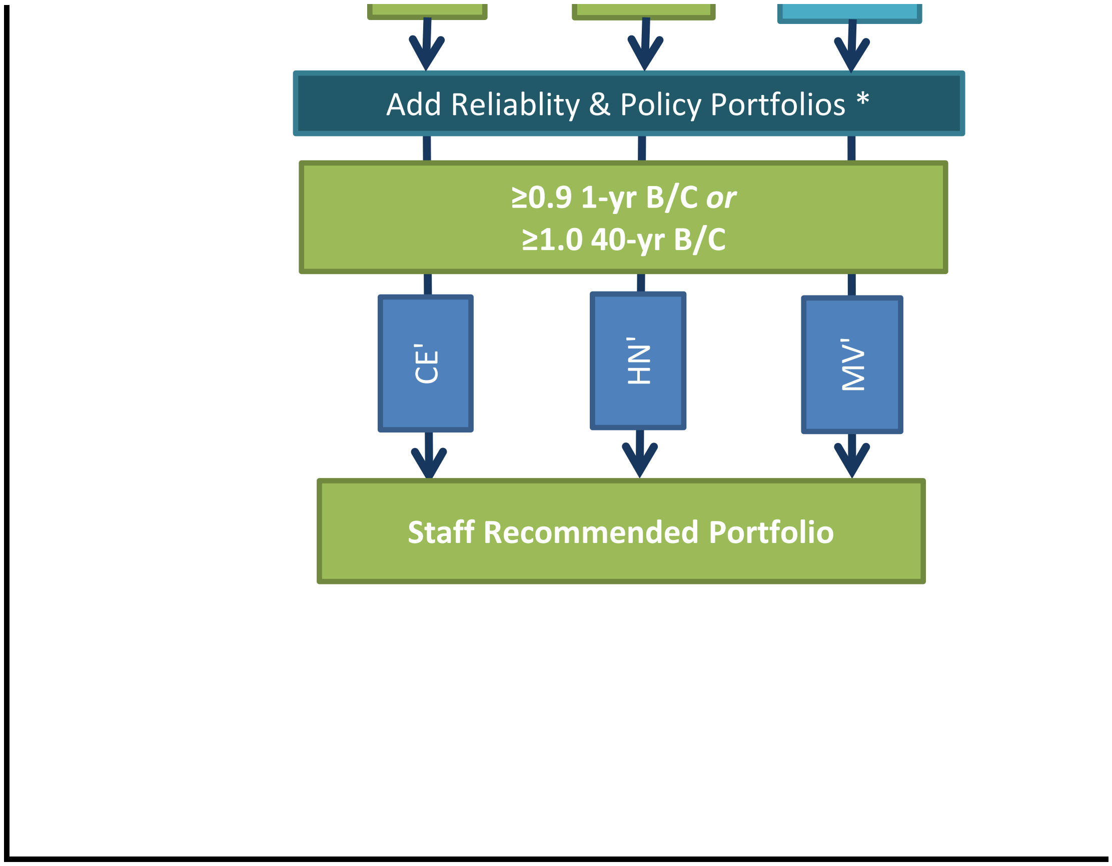
- Request Study level (±30%) cost estimates for top performing and alternative projects
- Re-rank only projects that have Study level estimates to create a new list of best performing projects by Need or set of Needs for each group by year
- Apply 0.9 1 Year B/C or 1.0 40 year NPV B/C as appropriate when removing projects to refine groupings
- Consolidate 2, 5, and 10 year project ranking results for each group
- Opportunity for Stakeholder review and feedback at Planning Summit
- Start consolidation process on Staff determined Portfolio

Staff Recommendation

SPP Staff recommends that the ESWG approve the methodology Project Screening and Portfolio Development as presented

Economic Project Select
Developm




Add Reliablity & Policy Portfolios *
≥0.9 1-yr B/C *or*
≥1.0 40-yr B/C
CE'
HN'
MV'
Staff Recommended Portfolio

ion and Portfolio
ent

Apply Seams Screening Criteria

Color Key

Criteria

Action

Stakeholder Feedback (Summit)

*Operational Economic projects may be applied here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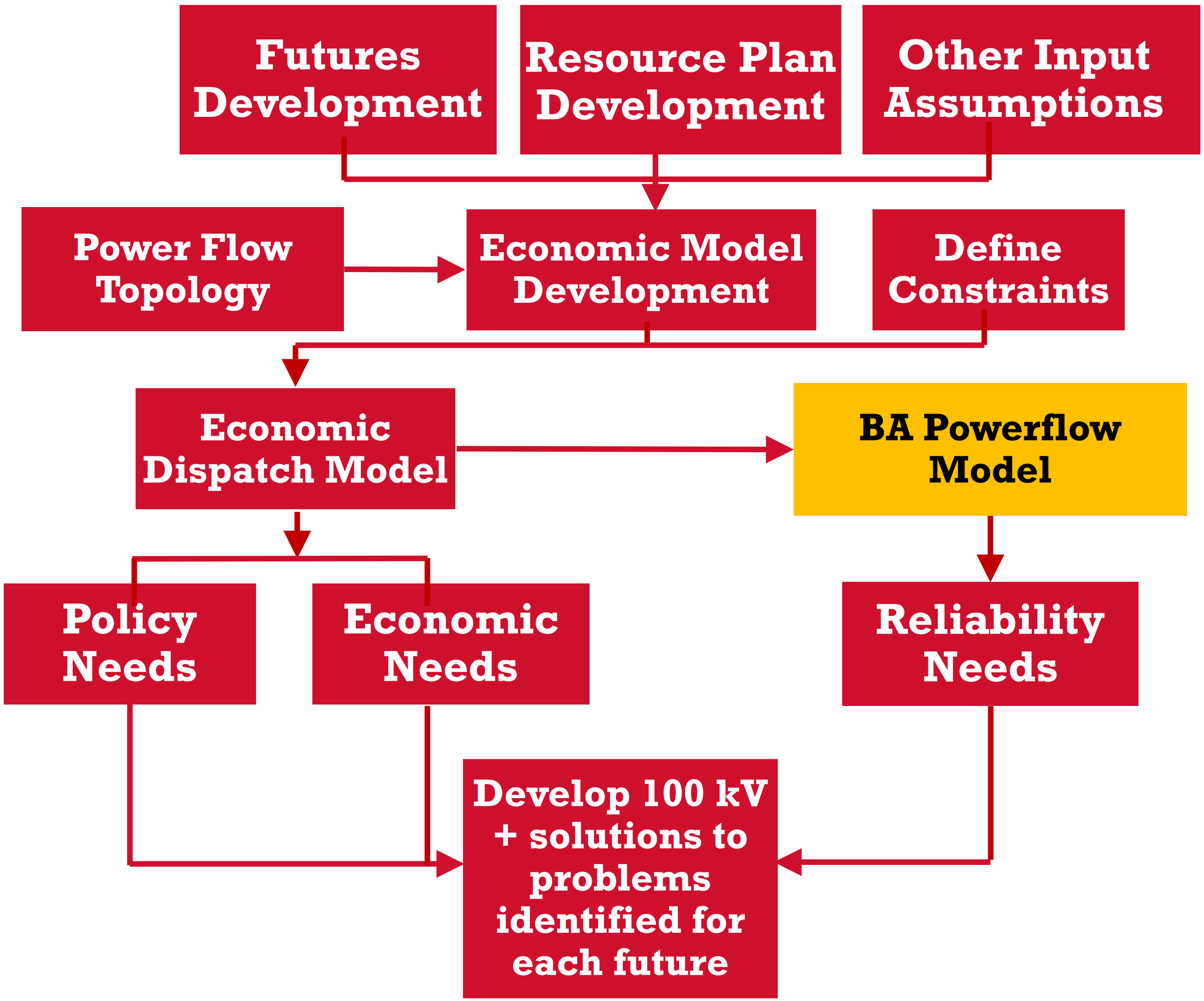
ITP Scope Standardization – DC to AC Model Conversion

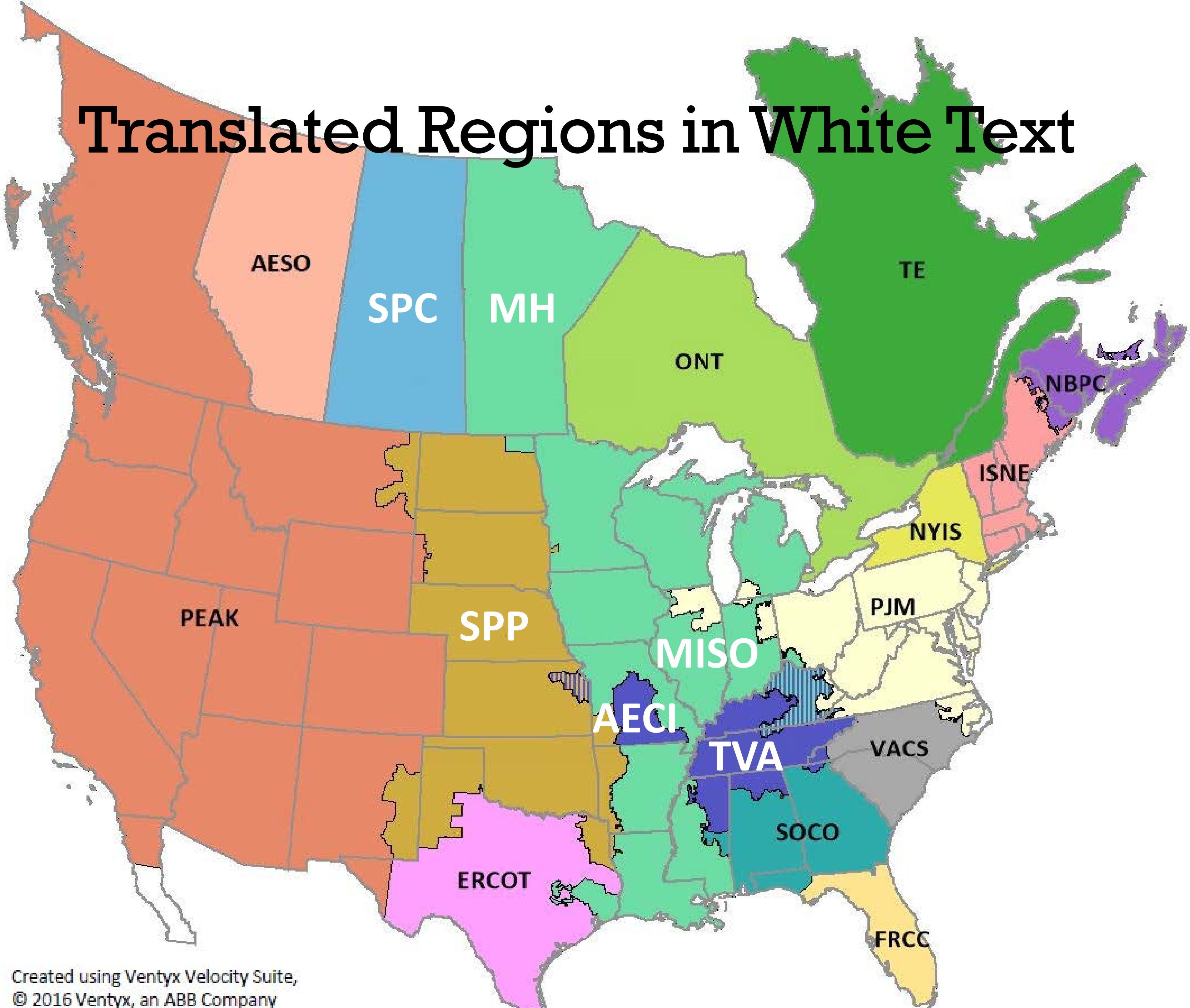
ITP10 Process



DC to AC Model Conversion Process

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

Translated Regions in White Text



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Issues Background

- AC thermal overloads were identified in the 2017 ITP10 powerflow models that were also defined as constraints (flowgates) in the DC simulation
- Differences DC and AC thermal loadings are largely thought to be caused by:
  - AC versus DC powerflow differences (MW vs. MW/MVAR)
  - System losses modeling differences (approximating transmission losses at the load in DC analysis)
  - External system modeling differences (external transaction assumptions to non-translated regions)
  - Phase-shifting transformer modeling differences (operating parameters)

SPP

2017 ITP10 Approach

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

SPP

Potential Adjustments

- External Transaction Modeling
  - Issue: external transactions proxy purchases and sales witn non-translated regions. These are modeled as large injections or withdrawals at EHV buses on the seam of the simulated regions.
  - Solution: remove transactions due to their small size relative to the simulated system

- Non-translated region powerflow modeling
  - Issue: generation in non-translated regions is scaled up to match non-translated load for the duration of the simulation. This is not done in the BA powerflow model as external transactions are expected to be a proxy for imports/exports to non-translated regions
  - Solution: incorporate output of all generators from production cost model simulation (assuming external transactions are removed)

Potential Adjustments

- Phase-shifting transformer modeling – process improvement approved by ESWG to better align economic and powerflow operation will improve flow mismatches
- Transmission losses modeling
  - Issue: transmission losses are approximated as a % of company peak and grossed up at the load causing a potential divergence from actual losses calculated by AC solution and thus generation dispatch required to
  - Potential solution: utilize production cost model transmission loss approximation to acquire generation dispatch

Potential Adjustments

- Perform security-constrained redispatch (SCRD) or security-constrained economic dispatch (SCED) utilizing TARA after AC powerflow model is developed
- Translated region scope
  - Issue: differences in flows on large EHV lines appear to be greater the closer the lines are in proximity to the edge of the translated system
  - Potential solution: expand the scope of simulated regions (e.g. PJM, SOCO)

Recommendation

- Adopt the solutions for external transaction modeling, non-translated region powerflow modeling, and transmission loss assumptions
- PST modeling recommendation already approved


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ITP Scope Standardization – DC Line Modeling- (Economic Model)

ESWG

May 17, 2017

DC Transmission Lines

- Historical modeling practice
  - DC line data comes from powerflow import into PROMOD
  - PROMOD defaults bi-directional ratings to MW line flow (DCSETVAL) set in powerflow model
    - DC lines always monitored in SCUC/SCED
    - Locks DC line flow to powerflow value for annual simulation
  - Some exceptions for 2017 ITP10
- Proposed practice
  - Allow SCUC/SCED to utilize line capacity within reasonable expectation
    - Determine seasonal line flows from powerflow model series for translated systems
    - Set maximum directional line rating limits based on highest seasonal expected flows (e.g. summer peak, winter peak, light load)
    - Set minimum rating to 0 (consistent with vendor and other RTO practices)
  - Case by case for certain lines
    - Set Coal Creek DC line to match Coal Creek plant output
    - Set Square Butte – Arrowhead DC line to match Bison wind farm output

ITP Manual Recommendation

- Model DC line limits based on consideration of operational practice (current or expected future) and/or limit operation to a maximum of expected flows modeled in AC powerflow models

SPP