Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

December 15th, 2014

Net Conference

• SUMMARY OF ACTIONS TAKEN •

1. None

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• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:03 AM, welcomed those in attendance, and asked for introductions.

There were 26 web conference participants representing 9 of 13 ESWG members. (Attachment 1 – December 15th, 2014 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements.

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. (Attachment 2 – December 15th, 2014 Agenda)

> **Paul Dietz (Westar) made a motion; seconded by Wayman Smith (AEP) to adopt the agenda. The motion was approved unanimously.**

Agenda Item 2 – ITP Manual Review

Paul Dietz (Westar) walked the group through the changes to the ITP Manual made by the Task Force and asked for feedback. Some of the sections changed were accepted by the group, some discussed and reworded, and some left open for more language to be added. The group will discuss more at the next meeting in order to pass on to the TWG for review. SPP Staff will (Attachment 3 - ITP_Manual - Task Force - combined edits_v3)

Agenda Item 3 – 2014 Organizational Group Survey

This item will be covered in a future meeting.

Closing Items

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

The meeting was adjourned at 10:00 AM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

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Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

December 15th, 2014

Net Conference

• A G E N D A •

8:00 am – 10:00 am

1. Administrative items
   a. Call to Order, Introductions.. Alan Myers (5 minutes)
   b. Receipt of Proxies .... Kelsey Allen (1 minute)
   c. Review of Agenda .... Alan Myers (1 minute)
2. ITP Manual Review .... All
3. 2014 Organizational Group Survey .... Kelsey Allen
4. Closing Items .... All

Integrated Transmission Planning Manual

Revised: 09/02/2014

ITP Manual Task Force

Southwest Power Pool

Revision History

Date	Author	Change Description
10/13/2010	SPP Staff	Initial Draft approved by the MOPC.
1/7/2011	SPP Staff	Incorporated TWG and ESWG edits to the ITPNT and ITP20 sections.
6/27/2011	SPP Staff	Includes the TWG and ESWG approved ITP10 section and minor changes to other sections.
7/13/2011	SPP Staff	Revised Draft approved by the MOPC.
9/02/2014	SPP Staff	Revised by the ITP Manual Task Force

Table of Contents

1 ITP Introduction

1.1 Purpose

The SPP Open Access Transmission Tariff (OATT), ~~in~~ Attachment O Section III.8.e, requires ~~that~~ the Southwest Power Pool, Inc. (SPP) to assess the cost effectiveness of proposed transmission projects in accordance with the Integrated Transmission Planning (ITP) Manual. This manual will ~~also~~ outline the processes for the three Integrated Transmission Planning components: 20-Year, 10-Year, and Near-Term Assessments.

The first phase of the ITP process is the 20-Year Assessment, which will be used to examine the need for additions to the SPP Extra~~lectric~~ High Voltage (EHV) backbone network over a twenty year horizon. The 20-Year Assessment is intended to study the plausible long-term high voltage transmission needs of the SPP region. Because the level of uncertainty over a 20 year horizon is higher relative to the 10-Year and Near-Term Assessments, the range of future scenarios examined will normally be broader. This study will give the SPP guidance as to the high voltage transmission needs of the region under a variety of plausible scenarios. The information learned will serve as guidance in the other shorter horizon studies so that SPP has a better understanding of which designs for solutions in those studies make sense over the longer term. In this way SPP will be better equipped to construct a system that is flexible enough to address changing needs over time while at the same time striving for a no regrets goal where the transmission authorized to be built by SPP does not result in over or under investment.

~~The first phase of the ITP process is the 20-Year Assessment~~ (ITP20) ~~which will be used to develop an EHV backbone network.~~ The ITP20 is a value-based planning assessment that will be employed ~~use~~ using a diverse array of power system and economic analysis tools to thoroughly study the SPP transmission system and to identify cost-effective and robust backbone projects needed to meet each of a broad array of future scenarios and provide information as to a grid design flexible enough to reasonably accommodate all of these scenarios~~possible changes characterized by the various scenarios~~. Thus, the study will produce a design for each of the scenarios and provide information as to an overall design that will be flexible enough to anticipate the scenarios while taking into account the likelihood of such scenarios occurring based upon the best available information. Because the degree to which the power transmission landscape will change over this time frame is not currently known, transmission system expansion is designed with flexibility (i.e., enables the ability of the transmission grid to meet a range of possible resource futures) in mind. The projects identified in the overall design as a result of the ITP20~~20-Year Assessment~~ are expected to provide benefits to the region across multiple scenarios. Designs for each scenario and the overall design will provide information that can be used for the Year-10 and Near-Term Assessments, capturing the needs under particular scenarios that ~~that~~ may be used if it is apparent over time that they are more likely to become reality. While Notices to Construct (NTC's) will not be issued for projects identified through the ITP20, these projects will provide a "pool" of potential solutions that can be analyzed in subsequent phases of the ITP Process.

The second phase of the ITP process is the 10-~~y~~Year ~~planning horizon a~~Assessment (ITP10). The~~is~~ ~~10-Year Assessment (~~ITP10~~)~~ is a value-based planning approach that will analyze the Transmission System in year 10 and identify 100 kV and above solutions to issues stemming from multiple sources including: (a) the issues that are identified in the reliability analysis of the 69 kV and above system, and (b) issues identified by the ITP20 process which are appropriate for the ITP10 study.

The ITP10 process will be similar to the ITP20 process. The ITP10 will evaluate the need for the ITP20 projects ten years out. It may also evaluate (based upon updated information) the cost effectiveness of such design including whether projects in the ITP 20 should be eliminated or changed and whether other projects should be added. Changes to the ITP 20 design should be based upon changes to the assumptions originally made in the ITP 20 that should be modified in the ITP 10 because of better information becoming available. The high voltage design will be ~~and~~ integrated ~~them~~ with 100 kV and above facilities that satisfy needs such as: a) resolving potential criteria violations; b) mitigating known or foreseen congestion; c) improving access to markets; d) staging transmission expansion; and e) improving interconnections. Economic and reliability analyses will be utilized as a way to further refine and establish the staging of the projects. Economic analysis will aid in determining those projects that are the best project alternatives for the 10 year plan. In the ITP10, the ITP20 futures ~~will~~may be used as a guide for development of the futures most likely occurring within the 10-year horizon. Generally, the array of future scenarios in the ITP 10 will be narrower than the ITP 20 and when reasonable utilize a subset of the most likely scenarios utilized in the ITP 20. This will allow the designs produced in the ITP 20 to have greater applicability and value in the ITP 10. However, judgment will be employed in varying future scenarios in the ITP 10 from the ITP 20 to take into account changes that have occurred since the ITP 20 study was performed. The primary focus of the ~~10-year assessment~~ITP10 is to determine the needs in the horizon year. However, the 10-year assessment may also analyze the need for projects within the 10 year period as well. NTC's may be issued for projects identified through the ITP10.

~~Economic and reliability analyses will be utilized as a way to further refine and establish the staging of the projects. Economic analysis will aid in determining those projects that are the best project alternatives for the 10 year plan.~~

The ITP Near Term (ITPNT) addresses reliability issues within the SPP system. The ITPNT~~-Near Term~~ is done every year in conjunction with the ITP-10 and ITP-20. Projects approved out of the ITPNT~~-Near Term~~ are for reliability purposes and have in-service dates within the next 4 years.

SPP Staff will take all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the SPP Tariff (i.e., Sections 17.2(iv) and 18.2(vii); Attachment V (Section 13.1 and Article 22 of Appendix 6); Exhibit 1 (Section 2.3); Attachment AJ (Section 8); and Attachment C-One (Clause 7)).

1.2 Process

1.2.1 ITP Planning Horizon Overview

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

The SPPT recommended that the organization adopt a new set of planning principles; develop and implement an ITP process; develop a plan to monitor the construction of projects approved through the ITP process; and identify Priority Projects that continue to appear in system reviews as needed to relieve congestion on existing constraints and connect SPP's eastern and western regions. The

SPPT recommended that the Regional State Committee (RSC) establish a “highway-byway” cost allocation methodology for approved projects.[1]

The SPPT created the following principles to drive development of the ITP process:

- Focus on regional needs, while considering local needs as well; long range plans (both ITP20~~-year~~ and ITP10~~-year~~) are to be updated every three years while ~~near-term~~ITPNT plans are to be updated annually.
- Plan the backbone transmission system to serve SPP load with SPP resources in a cost-effective manner. The transmission backbone will:
    - Enhance interconnections between SPP’s western and eastern regions
    - Strengthen existing ties to the Eastern Interconnection.
    - Provide options for planning and coordination to the Western Electricity Coordinating Council (WECC) and the Electric Reliability Council of Texas (ERCOT) grids in the future.
- Incorporate 20-year physical modeling and 40-year financial analysis timeframes.
- Better position SPP to proactively prepare for and respond to national priorities while providing flexibility to adjust expansion plans.

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

The ~~Integrated Transmission Plan (ITP)~~ ITP process is SPP’s approach to planning transmission needed to maintain reliability, provide economic benefits and achieve public policy goals to the SPP region in both the near and long-term. The ITP process enables SPP and its stakeholders to facilitate the development of a robust transmission grid that provides regional customers improved access to the SPP region’s diverse resources. ~~Development of the ITP process was driven by planning principles developed by the Synergistic Planning Project Team (SPPT), including the need to develop a transmission backbone large enough in both scale and geography to provide flexibility to meet SPP’s future needs.~~

The ITP process is an iterative three-year process that includes 20-Year[2], 10-Year, and Near-Term Assessments and targets a reasonable balance between long-term transmission investment and customer congestion costs (as well as many other benefits).

The ITP process was designed to create~~s~~ synergies by integrating ~~existing~~ SPP transmission planning activities which existed prior to its creation including: the ~~Extra High Voltage (~~EHV~~)~~ Overlay, the Balanced Portfolio, and the SPP Transmission Expansion Plan (STEP) Reliability Assessment. Consequently, and reaching the balance above, efficiencies are expected to be realized in the Generation Interconnection and Aggregate Transmission Service Request study processes. The ITP process works in concert with SPP’s existing sub-regional planning stakeholder process, and parallels the North American Electric Reliability Corporation Transmission Planning (NERC- TPL) Reliability Standards compliance process.

Comment [WM1]: Do we want to spell this out?

The Economic Studies Working Group (ESWG) was also formed in conjunction with the development of the ITP process and will identify and maintain the processes, modeling assumptions for various futures and metrics on an ongoing basis for qualifying and quantifying the transmission projects for the ITP20~~-Year~~ and ITP10~~-Year~~ Assessments.

[1] The Highway-Byway cost allocation was approved by FERC on June 17, 2010. http://elibrary.ferc.gov/idmws/nvcommon/NVintf.asp?slcfilelist=12369183:0

[2] The first iteration of the 20-Year Assessment is studying only year 20. However, in the future, ~~ITPs~~ multiple years may be studied in addition to ~~the~~ year 20.

The Transmission Working Group (TWG) will identify and maintain the process, model assumptions and local reliability requirement review on an ongoing basis for qualifying and quantifying the transmission projects for the ITPNT~~Near-Term~~ Assessment.

ITP recommendations that are reviewed and endorsed by the Market Operations and Policy Committee (MOPC) and approved by the ~~Board of Directors (~~BOD~~)~~ will allow staff to issue ~~Notification to Construct (~~NTC~~)~~ letters for approved projects needed within the financial commitment horizon. ~~An Authorization to Plan (ATP) will be issued for projects needed beyond the financial horizon.~~

Comment [KMF2]: ATP's are gone I assume

~~Once an ATP is issued, the project will be reviewed annually to ensure the continued need for the project and the proper timing.~~

Successful implementation of the ITP process will result in a list of transmission expansion projects, projected project costs and completion dates that facilitate the creation of a cost-effective, robust, flexible and responsive transmission network in the SPP footprint.

1.2.2 Process

The ITP process is an iterative three-year component of the SPP Transmission Expansion Plan (STEP) that includes 20-Year, 10-Year, and Near-Term Assessments. ~~Each of these assessments~~The 20-Year and 10-Year assessments target~~s~~ a reasonable balance between the cost of long-term transmission investment on one hand and the benefits of reducing customer congestion costs, and meeting reliability and policy needs, on the other. ~~Investment in transmission lowers the congestion costs (among many other benefits) to which customers are exposed but this benefit must be weighed against the cost of the investment.~~ As each assessment concludes, more clarity is provided concerning appropriate investments in new transmission. Finding the appropriate investments is dependent on the assumptions used to represent possible future outcomes. This targeted approach is both forward-looking and proactive by designing with an end in mind of having a cost-effective and responsive transmission network which adheres to the ITP principles and also keeps the FERC "Nine Transmission Principles" in the forefront.[3]

Comment [WLS3]: The ITPNT does not currently consider congestion costs (although I think it should)

Generally, ~~T~~the ITP20~~-Year~~ and ITP10~~-Year~~ Assessments are conducted on alternating 18 month schedules as part of a three year cycle. The ITP20~~-Year~~ Assessment begins in year one and is completed midway through year two. The ITP10~~-Year~~ Assessment begins during the second half of year two and is completed at the end of year three. The ITPNT~~Near-Term~~ Assessment is performed each year to ensure reliability, protect the rights of long-term firm transmission customers and to incorporate local planning requirements.

Comment [TJO4]: Do we need a few sentences somewhere in this section to address situations like the current one of back-to-back ITP10 assessments, or that?

Analysis will be performed following the adoption of the study assumptions and will focus upon both cost-effectiveness, flexibility and robustness.

Cost-effective analysis is a form of economic analysis that allows for the most effective planning over a longer versus shorter term time frame. This is often referred to as "no regrets" analysis.~~compares the relative costs and outcomes (effects) of two or more courses of action.~~ The objective is to produce the most economical project planning over the longer term horizon. In

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

effect, the benefits side of the equation is held constant at some pre-determined standard of service, and various options over various time horizons for providing that standard of service are then compared, with the least-cost method identified as the preferred option. ~~This method is distinct from cost-benefit analysis, which assigns a monetary value to the measure of effect with the most balanced outcome of costs and effects is identified.~~
~~Cost-effective and cost-benefit analyses ask two different questions, "is~~ Is ~~the equation balanced?" and "How can I achieve my goals in the most effective manner?"~~

An evaluation of robustness involves a different perspective than does the cost effectiveness analysis. Robustness includes an evaluation of changes to cost-effective transmission plans for flexibility as well as incremental cost and benefits. Metrics of robustness may be quantitative and/or qualitative.

1.2.3 Ad-Hoc Special Studies

~~1.2.3~~ The SPP OATT allows for the use of 3 Ad-Hoc or Special Studies during the course of a year. The purpose of these special studies is to address new regulatory or industry changes that will significantly affect the SPP transmission system. An Ad-Hoc Study must be approved by the SPP Board of Directors with a target due date and specific scope of analysis.

1.3 Order 1000 ~~Impact~~and Interregional Coordination

SPP is responsible for coordinating transmission planning with each neighboring interconnected system. SPP will coordinate any activities and studies based on the agreements listed in Addendum 1 to Attachment O of the OATT. As part of the inter-regional coordination process, SPP will share system plans with neighboring entities and identify system enhancements on the seams. Additionally, a new competitive bidding window which includes submission of transmission ideas/solutions, review of those solutions, development of an RFP, RFP submittals and award will be used for projects that meet the Order 1000 qualifications for competitive bidding. SPPs Order 1000 page can be found here.

2 Long-Term ITP Assessments: ITP20 and ITP10

2.1 Future Development

Due to the uncertainties involved in forecasting future system conditions, a number of diverse futures or scenarios are considered that take into account multiple variables. Consideration of multiple futures or scenarios provides for a transmission expansion plan that evolves as economic, environmental, regulatory, public policy, and technological changes arise that affect the industry. Initiatives such as plug-in hybrid electric vehicles, smart grid, renewable electricity standards, environmental regulations, energy storage and conversion applications, and other future technologies change the way the electric grid is utilized. The futures are defined by the SPP Strategic Planning Committee (SPC) based on input from the ~~Economic Studies Working Group~~

Comment [WLS5]: This is a little cryptic. I think I get the point, but it could probably be explained a little better.

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Comment [S6]: Should this be broader to account for studies such as with AECI that are outside the scope of Order 1000?

Comment [TJO7]: Perhaps include a link to SPP's Order 1000 webpage.

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~~(~~ESWG~~)~~. ~~Based on direction of the SPC, the ESWG further develops the assumptions and the inputs for the futures.~~

Future scenarios for the ITP 20 will generally be of broader array because of the greater uncertainty that exits over the longer 20 year time horizon. These futures should be designed to provide valuable guidance to SPP beyond business as usual. These futures should not be constrained by what is likely but what is plausible. Futures in the ITP 10 should be narrower in scope and, unless otherwise warranted by changes in circumstances, be a subset of the immediately preceding ITP 20 Futures. The ITP 10 future scenarios should be plausible and not unlikely. Added weight may be given to those scenarios that are more likely.

Sensitivities within future scenarios may be performed to help inform decision makers on the advisability of different generation mixes and of transmission design. Sensitivities may be advisable in determining the appropriate generation mix in subsequent transmission design phases of the study. Such sensitivities can help determine trigger points when certain types of generation become more economic because of variability of fuel prices and other costs impacting the construction or use of different kinds of generation or whether certain generation may be retired. Sensitivities within future scenarios in the transmission design phase will help to illustrate how different dispatch patterns might impact the need for different upgrades within a scenario due to changes in flow patterns.

~~The futures used in the ITP process will be developed by SPP staff and stakeholders with endorsement by the Strategic Planning Committee. Consideration of these futures will allow the ITP to take into account variability by considering the economic, environmental, regulatory, and technological changes likely to affect the electricity industry. Initiatives such as plug-in hybrid electric vehicles, smart grid, Renewable Electricity Standards, energy storage, and other future technologies will change the way the electric grid is utilized.~~

Comment [WLS8]: Seems redundant with the preceding paragraph.

2.2 Modeling Data & Assumptions

The analysis for the ITP20 and ITP10 will consist of engineering models used to facilitate the development of long range transmission plans. The ~~models~~analysis will be performed ~~will~~utilizing both ~~be~~ economic as well as reliability models that ~~are based on~~reflect a market based dispatch. These models require an extensive set of input assumptions ~~as to~~that include generation resources, parameters and locations. The output of these models will allow engineers to determine the appropriate transmission needs from a regional perspective.

The major input assumptions needed to construct the models contain, but are not limited to: market structure, load forecasts, fuel pricing and availability, transmission topology, resource forecasts and parameters, and others.

Each stakeholder has the opportunity to submit data and review their individual data which is being used for the study. Stakeholders can then provide specific updates to non-sensitive data. Sensitive data, such as heat rates, will not be updated by stakeholders. Multiple Stakeholder reviews are used to coordinate the submitting and vetting of all data used in the economic analysis:

- Load ~~Forcast~~ Forecast Review
- Policy Survey
- Generation Resource Plan Review
- Economic Model Review
- Constraint Assessment Review

The data captured in these reviews includes generating unit information, load, renewable requirements, emission prices, etc., to be included in the study models.

The starting economic dataset to be used in the model will be a commercially available model provided by the software vendor. This data as well as the powerflow dataset will be available to SPP stakeholders for review after the appropriate non-disclosure agreements have been signed. When possible, publicly available data will be used as data for the model runs. This includes data sets such as fuel curves, common assumptions or other data designated as not proprietary or confidential.

2.2.1 Footprint

The modeling footprint includes the entire SPP region and nearby areas within the Eastern Interconnection. The non-SPP areas that may be modeled are MAPP, Midwest ISO, and the western portions of PJM and SERC. In the event of pending changes in the footprint of a region it may be advisable to utilize additional sensitivities or scenarios to anticipate and understand the impact of such changes on the transmission needs of the SPP.

2.2.2 Fuel & Emission Prices

SPP staff assists the ESWG to formulate the fuel and emission price forecasts. These forecasts are then approved by the ESWG for use in the production cost model.

2.2.3 Load Forecasts

A base load forecast used for the ITP20~~-Year~~ Assessment and ITP10~~-Year~~ Assessment is developed by the Model Development Working Group (MDWG) and reviewed by the Transmission Working Group (TWG) and the ESWG. Load forecast sensitivities are utilized for the ITP20~~-Year~~ Assessment.

~~The ITP10 will require load forecasts for SPP members and non-members within the SPP footprint, as well as areas outside of the SPP footprint. SPP staff will use the load as represented in the MDWG models for the modeling footprint at the review of the MDWG. Energy forecasts, unit retirements or changes not captured in current models will be provided by the ESWG, TWG and other SPP staff contacts.~~

Comment [TJO9]: Is this paragraph realy providing any new information? Do we need it?

For load forecasts for entities outside of the SPP footprint, publicly available data will be utilized as the source of the load forecast, where available. Where not available, publicly available information on projected load growth will be extrapolated to develop a good representation for load expected in the study timeframe.

2.2.4 Resources

2.2.4.1 Conventional Resources

2.2.4.1.1 Existing Generation

Generating unit modeling data is required to perform a detailed analysis of economic upgrades. Stakeholders are asked to review the data inputs for their generating units as part of the Economic Model Review. These data types include: Variable Operations & Maintenance (O&M), Variable O&M Escalation, Fixed O&M, Fixed O&M Escalation, Energy Bid Cost, Energy Bid Markup, Spinning Reserve Bid, Spinning Reserve Bid Escalation, Heat Rate, Startup Cost Adder, and Startup Cost Adder Escalation.

Stakeholders are asked to review and provide updated values (if necessary) for non-sensitive data items. These data items include, but are not limited to: Maximum ~~-~~Capacity, Minimum Capacity, Must-Run status, Minimum Up Time, Minimum Down Time, Ramp Rate, Forced Outage Rate, Forced Outage Duration, Maintenance Hours Requirement, Minimum Runtime, Startup Energy Requirement, Fuel Type, and Emission Rates. Those stakeholders that have Integrated Resource Plans (IRP) that are submitted to their state are asked to coordinate the information in their IRP plan with the ITP.

The resource planning input data is vetted by stakeholders to ensure that the modeling of stakeholder's existing generation capacity and load positions are accurate. ~~The stakeholders also have the opportunity to update their new generation data to ensure the resource plan is being implemented in a reasonable fashion. This data may include generator type and location of each new conventional or renewable resource.~~

Comment [WLS10]: Moved to New Generation section

2.2.4.1.2 New Generation

The ESWG will develop a resource plan for each future scenario based upon expected unit retirements, unit derates, capital costs, O&M costs and other costs similar to those taken into account in data inputs for existing units, as well as ~~and~~ other relevant factors as part of the development of a resource plan for each future. The Resource plan will be reviewed by the load serving entities for accuracy before modeling. Stakeholders have the opportunity to update their new generation data to ensure the resource plan is being implemented in a reasonable fashion. This data may include generator type and location of each new resource. The siting of Sensitivities may be employed in providing additional information to develop the final resource plan for each future scenario.

Comment [TJO11]: Given the more extensive discussion in section 2.3.1.1, do we really need this section?

2.2.4.2 Renewable Resources

2.2.4.2.1 Existing Generation

Generating unit modeling data is required to perform a detailed analysis of economic upgrades. Stakeholders are asked to review the data inputs for their generating units as part of the Economic Model Review. These data types include: Variable O&M, Variable O&M Escalation, Fixed O&M, Fixed O&M Escalation, Energy Bid Cost, Energy Bid Markup, Spinning Reserve Bid, Spinning Reserve Bid Escalation, Heat Rate, Startup Cost Adder, and Startup Cost Adder Escalation.

Comment [TJO12]: Do we need to include some discussion of the Renewable Policy Survey?

Comment [KA13R12]: Yes

Stakeholders are asked to review and provide updated values (if necessary) for non-sensitive data items. These data items include but are not limited to: Maximum ~~-~~Capacity, Minimum Capacity, Must-Run status, ~~Minimum Up Time, Minimum Down Time,~~ Ramp Rate, Forced Outage Rate, Forced Outage Duration, ~~Maintenance~~and Maintenance Hours Requirement~~, Minimum Runtime, Startup Energy Requirement, Fuel Type, and Emission Rates~~. In addition, the most recent year's

Comment [WLS14]: Need to update this section to reflect the unique nature of renewable resources historical renewable output characteristics are developed for each resource, where applicable, namely wind and solar.

~~The resource planning input data is vetted by stakeholders to ensure that the modeling of stakeholder's existing generation capacity and load positions are accurate. The stakeholders also have the opportunity to update their new generation data to ensure the resource plan is being implemented in a reasonable fashion. This data may include generator type and location of each new conventional or renewable resource.~~

2.2.4.2.2 New Generation

Futures may require the modeling of additional wind and other renewable generation capacity above what is currently in service at the time of the assessment. The amount of ~~wind and other renewables~~ renewable generation modeled is to be determined either as defined in futures identified in the scope, which is proposed by the ESWG and approved by the appropriate governing committee or through the analysis of the generation resource mix to be used in each future. The additional target ~~wind~~ renewable level is then met by including additional ~~wind~~ renewable generation sites in the modeling footprint. The size and locations of these additional ~~wind farms~~renewable sites are approved by the ESWG. The ESWG will develop the locations of the renewable generation to be added taking into account the following factors: potential capacity factors as indicated by data from NREL; the SPP generation interconnection queue;- known environmental obstacles to development; transmission capacity that exists in areas of SPP that are attractive for the location of renewable generation; the location of the need for the renewable generation; and other factors deemed relevant by the ESWG. The object of the generation added should take advantage of the best renewable resources within the SPP while taking into account the level of interest in development, the barriers to development, and the cost effective integration of the generation into the SPP region.

2.2.5 Import/Export Limits

In determining projects that will be built as a result of ~~T~~the ITP process, the focus~~es~~ is on benefits to the SPP region. Unless otherwise called for in the assumptions of a future scenario, ~~T~~the interchange between SPP and other regions is ~~kept to a minimum percentage of SPP's total load and capacity. The imports and exports are~~ set and benchmarked to historical levels using hurdle rates and expected external system conditions during the time period under study~~for twenty years in the future~~. The ESWG reviews the hurdle rates and the resulting imports/exports for both the resource planning and production cost modeling phases of the study. Different hurdle rates may be used to accommodate import and export scenarios within the futures depending on the study scope. The system representation along the~~at~~ "seams" is reflective of expected facilities and arrangements that are consistent with the SPP futures being modeled. ~~All of the ties within the SPP footprint are modeled based on historical data. This historical data is the most recent year available.~~

DC ties connect the SPP region to the WECC and ERCOT systems. Sold firm transmission service will be used as a basis for modeling the flow levels of the DC ties. The ESWG will evaluate whether historical flows are consistent with the service agreements. [4] If there is no sold firm transmission service on DC ties, the ESWG will consider how to model the DC ties consistent with the developed futures.

Comment [KA15]: Need some discussion on intermittency and policy survey.

Comment [WLS16]: Isnt this covered in the 2nd sentence ?

[4] In the 2011 ITP10, SPP used historical DC tie usage profiles as an approximation for the respective power flow across the DC tie.

2.2.6 Environmental Regulation

~~2.2.6~~ During the course of the ITP Process, environmental regulations may change or be in a state of flux during the ITP assessment period. The ESWG and SPC will include key environmental regulations in their development of the futures.

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2.2.7 Sensitivities

2.3 Model Development & Analysis

2.3.1 Model Development

As described in the sections below, the models used in the ~~20-Year Assessment~~ ITP20 and ITP10 are developed based on information accumulated from various sources. The economic model building process starts with a package utilizing commercially-available data. Data from SPP ~~members~~stakeholders, Tier 1 entities, and~~, if possible,~~ data from other entities or RTO's in the Eastern Interconnect (where available) ~~is~~ are also incorporated into the model. In addition, ~~the~~an SPP powerflow model appropriate for the year(s) under study is imported into the economic model so that the transmission topology is up-to-date. Other parts of the model development include adding a generation expansion plan (resource planning) and developing a list of constraints (flowgate selection). Note that SPP does not use Transmission Operating Guides in its 20-Year or 10-Year Assessment analyses. The economic model, or a package of modeling data for those without th~~eis kind of~~ required software license,is ~~then~~ made available for review~~ed~~ by SPP members.

The powerflow model used in the ~~20-Year Assessment~~ITP20 and ITP10 is based on the ~~latest~~most recent series of MDWG models as approved by the TWG. Approved STEP projects as well as other special projects which are known by SPP staff (~~i.e.~~e.g. Entergy (MISO South), AECI projects or those at other seams) are added to the latest MDWG model as of the beginning of the study. In addition, the power flow model may be modified as required to reflect the facilities necessary to more accurately represent the topology near generating facilities that may have been simplified in the MDWG models. This powerflow is uploaded into the economic dispatch model.

For reliability analysis, the ~~P~~power flow models based on MDWG developed models will be used as a starting point and a ~~incorporating a~~ market dispatch developed as part of the security-constrained economic analysis will be incorporated. These models will be developed for the SPP system coincident peak load and off-peak load (or other seasons/scenarios as required) using output from the economic models as a reference for load and generation dispatch.

In general, the ESWG will oversee the development of the economic models. Similarly, the TWG will oversee the development of the power flow and stability models used in this analysis and they will be developed through the existing SPP Planning Model Process via the MDWG.

2.3.1.1 Resource Expansion Plans

For each future, SPP will complete ~~20-year~~ forecasts of generating resource additions to balance load and capacity reserves for zones throughout ~~the Southwest Power Pool (~~SPP~~)~~ based on future scenarios designed by the ~~SPP Economic Studies Working Group (~~ESWG~~)~~. Siting locations for the new resources for each of the futures will be determined under the general guidelines of this manual. The resource additions will be added to the SPP database at the sited locations and interconnected in the transmission network model at the appropriate locations.

The resource planning will be conducted in three phases as summarized below.

- **Phase I.** Develop a resource expansion plan for each future scenario. The resources will be selected using an optimal generation expansion model on a regional basis. The expansion plans will be developed from a resource list of generic prototype generators representing available future resources. The optimal generation expansion model will be constrained to maintain specified capacity margins, renewable requirements, and other parameters for each future.

- **Phase II.** The new resources will be spatially located within the SPP ~~pricing ~~sub-areas with the aid of GIS databases showing locations of transmission lines, natural gas pipelines, railroads, waterways, substations, etc as well as environmental maps and data indicating barriers to the location of generation; NREL studies on renewable energy potential; and data relevant to other factors that are to be used in the location of new resources pursuant to this manual~~-~~.

- **Phase III.** The generators will be entered into the SPP database and connected to busses in the transmission system.

2.3.1.1.1 Phase I

The data defining the generating characteristics of all existing and potential resources, demand and energy forecasts, fuel price forecasts, emission price forecasts, and other factors will be input to an optimal generation expansion model to evaluate combinations of candidate resources available to cost effectively meet future peak demand and energy requirements under the parameters of the applicable future scenario. This may include the addition of combinations of demand and supply resources as well as combinations of supply resources. ~~In addition, g~~Generators that are under construction or far enough along in the permitting process shall be considered for inclusion in the existing resource data. Firm retirements, to the extent known, will also be incorporated in the optimal generation expansion model.

Additionally, the parameters for each future will be entered into the optimal generation expansion model. The optimal generation expansion model will be used to determine the appropriate resources for the ~~20-year~~appropriate timeframe, maintaining the required minimum capacity margins, renewable requirements, and other parameters for each future.

Cost and performance estimates for representative generation technologies to be considered as generator resource additions will be entered into the optimal generation expansion model. An overall study estimate basis shall be developed to allow all technology costs to be presented on a consistent level. Technologies considered will include simple cycle combustion turbine configurations, combined cycle configurations, pulverized coal units, nuclear, integrated gasification combined cycle with carbon sequestration (IGCC), and renewable resources (wind, solar,…).

To capture the diversity of the geographic dispersion of wind generation in SPP's control region, hourly production profiles from several potential sites within the geographic regions that exhibit the best potential for wind installation development will be input to the optimal generation expansion model.

2.3.1.1.2 Phase II

After the sets of resources for each future are approved by the ESWG, the resources will be spatially sited. A physical spatial location for each generator will be selected based upon the siting parameters developed in collaboration with the ESWG and SPP staff. The resource sets will be provided to Transmission Owners for review. The siting effort will incorporate renewable ~~requirements~~needs, and other futures parameters, as well as physical siting criteria to determine the proper location for each resource. This siting effort will be conducted as a screening level exercise to identify site areas that generally comply with the approved criteria and will not be intended to provide or replace a full scope power plant siting study. Siting criteria could include, but not be limited to, locating the resources within a certain distance from existing natural gas pipelines, existing railways, and/or navigable waterways, etc.

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

- Do not use transmission as initial siting factor**:** Let geography and existing infrastructure guide placement of proxy generation. Existing transmission used as a weighting factor rather than a primary siting factor.
- Site proxy generation by region: Site expansion of conventional model generation in zone with highest capacity needs.
- Avoid greenfield siting for NG fired capacity: NG generation is flexible to site. Locating generally more peaking NG generation near load centers will have a tendency to reduce the impact on the transmission system.
- Limit capacity to 2,400 MW maximum per location: Limiting total capacity per location potentially minimizes the impact of contingencies removing large blocks of capacity from service.
- Site base load non-nuclear steam capacity in 600 MW increments; nuclear capacity in 1200 MW

~~Should we add a section on siting for renewables or add renewable specific considerations to the conventional resource section ???~~

Comment [TJO17]: Yes

2.3.1.1.3 Phase III

After the resource sit~~ings~~es are approved, the new resources ~~additions~~ will be ~~input~~added to the SPP database and ~~with the resource additions at the approved sites so they could be~~ interconnected in the transmission network model at the appropriate locations. The data will be used in subsequent analys~~i~~es by SPP and will allow SPP to connect the resources to specific buses for the transmission models.

2.3.1.2 Constraint Selection

The nature of the economic study tools is such that the transmission constraints are the only tool in the model which controls the flow on the transmission lines – without the transmission constraints there is no adherence to the line or transformer limits, etc. The selection of transmission constraints is generally an iterative process that starts with an initial set of constraints and is then augmented with additional constraints through analysis of resource dispatch and transmission flows under contingency conditions.

The current NERC Book of Flowgates ~~can~~may be used as an initial list of constraints. Through a constraint selection ~~-~~analysis, SPP will define~~s~~ additional constraints which are vetted and approved by the TWG.

Using a transmission analysis tool, SPP staff may also identify~~ies~~ additional constraints related to defined interfaces which should be monitored in the economic dispatch model. ~~The nature of the economic study tools is such that the constraints are the only tool in the model which controls the flow on the transmission lines – without the constraints there is no adherence to the line or transformer limits, etc. This can be an iterative process which will look for the additional constraints once an initial set of constraints are added to the model.~~ In this analysis, Power Transfer Distribution Factor (PTDF) interface constraints will be selected in order to control the flow on transmission corridors where there are thermal loading and/or voltage stability interface limits.

Each constraint ~~will be~~ identified will includ~~ing~~e normal and emergency ratings. In addition, both summer and winter ratings may be used. For the purposes of the ITP20 study, the transmission constraint list will be limited to the following types of issues so that there is a focus on disturbances on the EHV system:

- System Intact and N-1 situations
- Existing common right-of way and tower contingencies for 300+ kV facilities[5]
- Thermal loading and voltage stability interfaces
- Contingencies of 345 kV or higher voltage~~s~~ transmission lines only
- Contingencies of transformers with a 345 kV or higher voltage winding only
- Monitored facilities of 115 kV and above voltages only

Comment [WLS18]: Need to update the footnote based on new NERC reliability criteria

For the ITP10 study, 100kV and above contingencies will be tested with ~~6~~100kV and above facilities monitored for potential overloads.

Comment [WLS19]: We may want to spell this out in more detail.

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

2.3.1.3 Project Screening Analysis

Comment [S20]: Assume this needs major revisions

With the addition of FERC Order 1000, stakeholders will need to provide solutions for screening through the Detailed Project Proposal (DPP) process. Stakeholders have 30 days to submit solutions through the DPP process. ~~SPP will start the screening analysis using prototypes which are developed based on previous EHV plans. These prototypes will be reviewed by stakeholders who have an opportunity to review the prototypes and offer feedback in their design.~~ SPP will analyze a wide variety of possible transmission projects which have been identified by staff or

Comment [WLS21]: I am not sure this is still applicable

[5] The current NERC Standard TPL-001-0.1 includes outages of any two circuits of a multiple circuit tower line within Category C, and the loss of all transmission lines on a common right-of-way within category D. NERC Standard TPL-001-2 will replace this standard (pending FERC approval) and includes such outages in Category P7 and Table 1 – Steady State & Stability Performance Extreme Events.

suggested by stakeholders. The purpose of the screening analysis is to identify the grouping of projects which meet the goals of the future cost-effectively.

Part of the data used in this screening analysis will be conceptual cost estimates developed by SPP.

2.3.1.4 Interregional Considerations

2.3.2 Modeling Analysis

2.3.2.1 ~~SCED &~~ SCUC ~~& SCED~~ & SCED Analysis

The economic dispatch model includes stakeholder-vetted data. Generating ~~U~~unit cost ~~related~~ data ~~such as costs~~ and heat rates are taken from commercially-available sources. ~~Other d~~Data ~~about~~related to the physical characteristics of generators ~~that are~~ (not related to unit costs ~~and~~or heat ~~rates~~ rates) is reviewed and updated as needed by the members to provide company-specific values. This data is used to produce the security-constrained economic dispatch (SCED) solution with the economic modeling software.

The SCUC/SCED solution requires dual optimization processes.

The first process is the security constrained unit commitment (SCUC). Here, the hourly least cost combination of units that should be committed (turned on) is determined subject to unit-specific operational constraints (e.g., ramping, minimum output, min/max runtime, startup cost, etc.), and some critical location-specific transmission reliability constraints (e.g., must-run operational limits); but without explicit consideration of transmission grid operational costs.

The second process is the ~~security constrained economic dispatch (~~SCED~~)~~ solution of the units ~~determined~~committed by the SCUC process. ~~Here~~In the SCED process, the units are dispatched (exact unit output determined) in a least-cost manner subject to various transmission operational constraints (e.g., line thermal limits, voltage support, etc.) and transmission reliability constraints (e.g., n-1 contingencies) to produce an overall least cost solution for regional load.

~~SPP staff will use a security constrained economic dispatch software for the economic and unit commitment analysis.~~ The SCUC and SCED model will solve using nodal LMPs which will commit and dispatch the generation economically based on unit characteristics, load information, and transmission constraints. This analysis will determine potential issues including congestion, LMP variation and trapped generation.

2.3.2.2 Reliability Assessment

In addition to economic modeling for identification of potential congestion, SPP staff will perform ~~a limited~~ a reliability assessment to identify potential needs in the study horizon.~~the impact the 20-Year transmission plans may have upon system reliability, in order to provide the most cost-effective, versatile backbone.~~ The purpose of th~~eis~~ reliability assessment is to determine areas on the system which may require transmission upgrades in order to comply with applicable reliability

Comment [WM22]: Since I'm not working in the markets, something here doesn't make sense to me. We are talking about the SCED solution requirements and then we move the first process of SCUC. This much makes sense. However, we then say the second process is the SCED. How can we need the SCED to produce the SCED. It seems like a chicken and egg thing. Perhaps someone with more direct knowledge could explain this to me sometime. Thanks.

standards.~~test the robustness of the transmission system and~~ The reliability analysis conducted as a part of the ITP process is not intended to be a replacement for the NERC Reliability Compliance ~~test for NERC Reliability Standards requirements~~Assessment[6].

The reliability analysis will consist of an AC (thermal and voltage) contingency analysis. For the ITP20, SPP will monitor 100 kV and above facilities while considering 300 kV and above contingencies within SPP and first tier neighbors. For the ITP10, SPP will monitor 60 kV and above facilities while considering 100 kV and above contingencies within SPP and first tier neighbor systems.

Comment [tjo23]: It makes more sense to me to move this paragraph from the following page to this location.

The power flow model that was developed and utilized in the economic model will be modified to incorporate the unit commitment, dispatch and load level associated with the specific hour(s) to be analyzed (e.g. summer peak, winter peak, light load, etc.) as specified in the study scope. The specific cases to be analyzed will be approved by the TWG as a part of the study scope development.

~~Due to the lack of an available year 20 powerflow model, a year 10 or year 11 powerflow model will be substituted as a proxy so that both voltage and thermal concerns can be evaluated. In order to be sure that the various futures and year 20 load levels are considered, analysis will also be performed on the year 20 cases.~~

~~In order to assess reliability from multiple aspects, the limited reliability assessment will be divided into two portions. The first portion will be performed on the year 20 economic model, simulating the 20 year load levels and dispatch. The analysis will consist of a DC (thermal) contingency analysis, with and without the identified transmission plans, monitoring the 100 kV and above system while considering 300 kV and above contingencies.~~

~~The second portion of the analysis will be performed on a year 10 or year 11 powerflow model, establishing a more thorough reliability evaluation of the 100 kV and above system. Theis reliability analysis will consist of an AC (thermal and voltage) contingency analysis., with and without the identified transmission plans. For the ITP20, SPP will monitor 100 kV and above facilities while considering 1300 kV and above contingencies within SPP and first tier neighbors. For the ITP10, SPP will monitor 60 kV and above facilities while considering 100 kV and above contingencies within SPP and first tier neighbor systems. In this analysis mitigation plans will be developed for all violations. Additionally, a transfer capability (FCITC) will be performed on the year 10 or year 11 powerflow model, with and without the identified transmission plans.~~

A stability screening study ~~will~~may be performed to identify potential areas of instability. These results may influence the selection of projects for the ITP. ~~[7]~~.

Those issues within SPP that are not addressed in this assessment ~~will~~may be passed to subsequent ~~the 10-Year A~~assessments for further evaluation. ~~Based on the results of these analyses, the EHV designs will be refined from a reliability perspective.~~

~~Using the power flow models developed in Section 2.3.1, SPP Staff will conduct AC contingency analysis to determine potential thermal and voltage violations.~~

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[6] Adherence to NERC Reliability Standards will continue to be checked through a separate NERC Reliability Compliance Assessment.

~~[7] For the 2010 ITP 20-Year Assessment, this analysis may not be performed.~~

2.4 Order 1000 Process

2.4.1 Model Review and Constraint Identification

2.4.2 Detailed Project Proposal (DPP) Open Window

~~2.4.2~~ As part of the Order 1000 process, the SPP OATT requires a 30 day window for stakeholders to submit DPP's. The DPP necessary information must be submitted within the prescribed 30-day transmission planning response window for DPP submittal in order to qualify as a DPP to be evaluated as a potential solution to the posted needs. The information required for a DPP submittal is included in the DPP Submittal Form. Upon receipt of the DPP submittal, SPP will verify that the DPP was received within the 30-day DPP transmission planning response window, based on the time and date of the email containing the DPP submittal, and verify that the DPP is complete. If a DPP Submittal Form was ~~is~~ received outside ~~of~~ the 30-day transmission planning response window, SPP staff will notify the Submitter via email that its submittal ~~does not DPP~~ has been disqualifi~~y~~ed for consideration for incentive points.

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2.4.3 Solution Development

During the ~~process of the 20-Year Assessment~~ITP20 and ITP10, SPP staff will review issues that are identified during the various phases of the study. Those issues may include: thermal overloads, voltage violations, flowgate congestion, LMP variation and trapped generation. Staff will ~~present~~post these issues and open the DPP Window as previously described.~~to stakeholders and ask for feedback on EHV solutions to those issues.~~ At that time, stakeholders may submit DPP's to address the identified needs. In addition, SPP Staff and other stakeholders may submit non-DPP solutions for evaluation as well. ~~Those p~~Proposed solutions (both DPP and non-DPP) will then be evaluated through a screening process to determine which solution sets ~~work best~~meet the needs of the study. The solution sets (or portfolios) that result from the screening process will be further developed and refined through more detailed analysis. ~~which will include evaluation of benefit metrics as described in Section III.G of this manual.~~

Comment [WLS24]: Not sure we really do this

Comment [WLS25]: I believe many of the metrics are only calculated on the final portfolio

~~During the process of the 10-Year Assessment, SPP staff will review issues that are identified during the various phases of the study. Staff will present these issues to stakeholders and ask for feedback on solutions to those issues. Those proposed solutions will then be evaluated to determine which solution sets work best. The resulting solutions will be further developed and refined through more detailed analysis which will include evaluation of additional benefit metrics as described in this manual.~~

Proposed projects that pass the initial screening will be placed in the economic model, and a full economic assessment will be performed. Benefit metrics will be used to distinguish the value of one set of projects over another ~~and net benefits of the ITP10 plan~~. The results from the economic analysis will be used to determine portfolios (groups of projects) which have higher benefits based on the benefit metrics used.[8] Sensitivities will be defined by the ESWG as input to the decision making process in order to identify potential variations in benefits.

[8] ~~These benefit metrics may be a subset of the metrics used for the ITP20, which will be reviewed by appropriate working groups.~~

Seams projects will be considered as potential solutions as part of the ~~ITP10~~ ITP20 and ITP10 study processes and expansion plans~~ as potential solutions~~, and SPP will collaborate with neighboring entities regarding the identified needs, benefits, potential solutions, and costs. For the neighbors that SPP has an agreement with, joint coordination will be done in accordance with that agreement.

2.4.4 RFP Process

~~2.4.4~~ TBD

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2.5 Deliverables

2.5.1 Recommended Transmission Plans

Prior to developing the final set of projects, SPP staff expects to have a transmission plan developed for each future. Those multiple plans will be analyzed to determine which projects or combination of projects would be beneficial in ~~all~~ multiple futures. The results of this analysis will be a single ~~EHV~~ transmission plan that is robust, being adaptable for all of the futures considered, and adding greater incremental value than incremental cost.

~~The ITP10 assessment will define a set of transmission upgrades that will be needed to meet the futures defined in this document. From these futures a recommended transmission plan will be developed as detailed in the ITP10 scope.~~

A project implementation plan will be developed for the recommended transmission plan. The final plan will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. Each element will have an economic, ~~or~~ reliability, or policy justification. NTCs will be issued for the ITP10 plan elements in accordance with the OATT~~Tariff~~, Attachment O, Section VI and SPP written procedures (see Business Practice 1.15[9]). ~~ATPs will be issued for the ITP10 plan elements in accordance with SPP procedures and business practices.~~

2.5.1.1 Benefit Metrics

Following is an overview of the 10 benefit metrics that will be considered in the ITP planning process when evaluating potential transmission projects and portfolios. For further detail on these metrics, refer to Appendix XX at the end of this document.

1. Adjusted Production Cost (APC) Savings

   The APC metric measures the effect on production cost savings relating to energy production by generating resources within the SPP footprint by considering Locational Marginal Price (LMP) for purchases and sales of energy between each area of the transmission grid. The APC metric quantifies the monetary cost associated with fuel costs, generation dispatch, most grid congestion, energy purchases, energy sales, emissions and ancillary services. The APC benefit

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[9] SPP.org > Org Groups > Access SPP's Governing Documents > OATT Business Practices

is calculated as the difference in the production cost simulations for the base case and the change case. These are aggregated up to a zonal level.

2. Reduction of Emission Rates and Values

Transmission projects relieve grid congestion and change generation dispatch which may result in cost savings associated with reductions to SO2, NOx, and CO2 emissions. Allowance prices for SO2, NOx, and CO2 emissions are used as inputs to the production cost model simulations and are specific to the various generating technologies modeled. This metric captures the cost savings associated with reduced SO2, NOx, and CO2 emissions through the change in generation dispatch and the assumed allowance price for these emissions. The reduction of emission rates and values is reflected in the APC savings.

3. Savings due to Lower Ancillary Service Needs and Production Costs

Ancillary Services (A/S) are essential to the reliable operation of the electrical system and are currently reflected in the APC savings mentioned above. A number of operating reserves and products fall into this category – spinning reserves, ramping up/down, regulation, 10-minute quick start. The difference in APC for base case and the change case reflects 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).

4. Avoided or Delayed Reliability Projects

If a larger project with economic or public policy benefits is pursued, the costs associated with the reliability projects that are replaced by the larger project represent the avoided or delayed reliability project benefit of the larger project. The steps taken to determine which reliability projects were replaced is outlined in Appendix XX at the end of this document. The avoided (or delayed) reliability project benefit is captured as the avoided cost of delaying or canceling previously approved reliability projects. The benefit is allocated in accordance with the ratios of the allocation that would have been applied for the costs of the reliability project.

5. Capacity Cost Savings due to Reduced On-Peak Transmission Losses

This metric captures the value of generation capacity that may no longer be required due to a reduction in losses during the system peak. These capital savings will be calculated by applying the estimated net Cost of New Entry (CONE) to the reduction in installed capacity requirements. The net CONE is the difference between the annualized CONE and the annual energy and ancillary service profits a unit of this type is expected to earn in the energy and ancillary service markets. Monetization of the capacity cost savings will be calculated using the savings in capital attributed to the corresponding MW reduction in installed capacity requirements.

6. Assumed Benefit of Mandated Reliability Projects

This metric captures the inherent value of maintaining transmission reliability. In evaluating projects within the portfolio that would be built to meet transmission reliability standards (i.e. classified as a 'reliability project' as defined in this manual), the benefit of fixing the reliability violation should be assumed to be equal to its cost. This benefit will be mutually exclusive from any other reliability benefit applied to those same projects and will be allocated using a hybrid approach that utilizes Load Ratio Share and System Reconfiguration, depending upon project size.

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7. Public Policy Benefits

This metric captures the value of meeting public policy goals or mandates related to renewable energy supplies, and the benefit is assumed to be equal to the project cost. 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 implementing a public policy. This benefit does not apply to economic decisions made by individual utilities to acquire renewable energy supplies absent some form of legal requirement to do so. Benefits will be allocated based upon the share of unmet renewable mandates or goals and only to zone(s) within the state(s) driving the public policy project(s).

8. Increased Wheeling Through and Out Revenues

While the energy revenue benefit of increased exports is captured by the APC metric, the APC metric does not capture any increases in wheeling out or wheeling through revenues associated with increased transfer capability. These increased wheeling revenues are a benefit as they will offset part of the transmission projects' revenue requirements. A historical average wheeling charge will be utilized to monetize the value of increased wheeling through and out transactions. These benefits will be allocated according to the methodology in the Tariff for allocating wheeling revenues.

9. Marginal Energy Losses Benefit

This metric captures the reduced MWh quantity of transmission losses that results from transmission expansions. Standard production cost simulations used to estimate the APC benefits assume a fixed MWh quantity of transmission losses which does not change with transmission additions. In reality, transmission projects can result in energy loss reductions and those can be estimated on a zonal basis through post-processing simulation results.

10. Mitigation of Transmission Outage Costs

This metric captures how the availability of new transmission projects decreases congestion and increases the operational flexibility of the system to mitigate the impacts of transmission outages. 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. Thus, the benefit of reducing this additional congestion is not captured in the standard APC metric. To measure the savings in transmission outage costs due to transmission expansion, the production cost modeling analysis will be modified to reflect a realistic level of transmission outages using a subset of historical transmission outage events.

~~The robustness metrics are described in more detail in the ITP 20 and ITP10 Year Assessment Robustness Metrics Procedural Manual[10]. These 15 metrics are meant to be options which can be used to capture additional value provided by projects studied in the ITP20 Year Assessment.~~

- ~~Captures added value not previously quantified/qualified in SPP's traditional planning methods.~~
- ~~Levelization of LMPs~~
- ~~Improved access to economical resources participating in SPP Markets~~

~~10 http://www.spp.org/section.asp?pageID=128~~

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Comment [WLS27]: Is this still accurate ? We need to update this to reflect recent changes in metrics.
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- ~~Change in operating reserves~~
- ~~TLR Reduction – Enabling Market Solutions~~
- ~~Limited export/import improvements~~
- ~~Improved economic market dynamics not measured in the security constrained economic dispatch model.~~
- ~~Improved economic market dynamics measured in the nodal security constrained economic dispatch model.~~
- ~~Reduction in market price volatility~~
- ~~Reduction of emission rates and values~~
- ~~Transmission corridor utilization~~
- ~~Ability to reduce cycling of base load units~~
- ~~Generation Resource Diversity~~
- ~~Ability to serve unexpected new load~~
- ~~Part of Overall EHV Overlay Plan~~

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2.5.1.2 Consolidation Process

2.5.2 Final Reports

The deliverable for the ITP20~~-Year~~ Assessment will be a cost effective EHV design for each future scenario analyzed and a cost effective single transmission plan that is flexible enough to allow SPP to meet these futures while timing and staging the anticipated construction of the projects in the design in an order that will protect from under and over investment. ~~including staging and timing considerations to convey the appropriate order of implementation.~~ The results of the analysis as outlined in this manual will be included in the ITP20~~-Year ITP~~ Report.

The deliverable for the ITP-10~~-year~~ assessment will be a cost effective design that takes into account the likelihood of the occurrence of the futures studied. In assessing the design those elements that are common to both will be used along with additional elements that can be incrementally added when the benefits are adjusted by the probability of the futures occurrence and weighed against their incremental cost. R~~r~~esults from the 10-Year Assessment will be compiled into a report detailing the findings and recommendations of SPP Staff. This report will be incorporated into the STEP Report that is published on an annual basis.

3 Near-Term ITP Assessment: ITPNT

3.1 Purpose

The third phase of the ITP process is the annual Near-Term Assessment, which will be performed annually on a rolling window to be defined in the ITP study scope document. This assessment will analyze the Transmission System for solutions according to NERC Reliability Standards while incorporating individual Transmission Owner planning requirements. The assumptions for this assessment will be narrowed further than those for the ITP20~~-Year~~ and ITP10~~-Year~~ Assessments. This narrower focus is intended to ensure continuous adherence to NERC Reliability Standards while allowing the ITP process as a whole to focus on the creation of a Transmission System that meets the ITP planning principles.

The ITPNT ~~Near-Term~~ Assessment determines the SPP upgrades required to meet reliability in the near-term, including those upgrades recommended to the SPP BOD to receive an NTC.

The ITP-20~~-Year~~ and ITP10~~-Year~~ plans will be incorporated into the ITPNT~~Near-Term~~ Assessment annually. The plans will serve as part of a pool of solutions from which the ITPNT~~Near-Term~~ plans are developed to determine the best regional solution for the SPP footprint. There will also be interaction of the plans based on issued ~~ATPs and~~ NTCs.

3.2 Modeling Data & Assumptions

Per SPP Criteria 3.5, when an entity is in the conceptual planning stages of new facilities that impact the interconnected operation of the Transmission System, it shall contact the Transmission Provider so that the optimal integration of any new facilities and potentially benefiting parties can be identified.

In preparation for the annual update of transmission planning models for each annual planning cycle, SPP Members, Transmission Customers and other stakeholders must provide to the Transmission Provider the data specified in Section VII of Attachment O of the OATT.

During the course of the annual planning cycle, if material changes to the data occur, the data owners must provide timely written notice to the Transmission Provider.

Instructions to access modeling information are posted on the SPP website.[11]

The ITPNT~~Near-Term~~ Assessment will be performed on an annual basis. The study will be performed on a shorter planning horizon than the ITP10~~-Year~~ assessment and will focus on the reliability of the system. The ITPNT~~Near-Term~~ Assessment will take the following into account:

- NERC Reliability Standards;
- SPP Criteria;
- Transmission Owner-specific planning criteria as set forth in Section II of Attachment O;
- Previously identified and approved transmission projects;
- Zonal Reliability Upgrades developed by Transmission Owners, including those that have their own FERC approved local planning process, to meet local area reliability criteria;
- Long-term firm Transmission Service;

[11] http://www.spp.org/section.asp?pageID=108

  - Accommodate and reflect the specific long-term firm transmission service requests of the Transmission Customers and specific interconnections of Generation Interconnection Customers no later than when the relevant Service Agreements and interconnection agreements are accepted by the Commission.
- Load forecasts, including the impact on load of existing and planned demand management programs, exclusive of demand response resources;
- Capacity forecasts, including generation additions and retirements;
- Existing and planned demand response resources; and
- In developing the long term capacity forecasts, the studies will reflect generation and demand response resources capable of providing any of the functions assessed in the SPP planning process, and can be relied upon on a long-term basis. Such demand response resources shall be permitted to participate in the planning process on a comparable basis to the service provided by comparable generation resources where appropriate.

TWG has oversight of the ITPNT~~Near-Term~~ Assessment.

Staff will use the SPP ~~Model Development Working Group (~~MDWG~~)~~ models as a starting point for the ITPNT ~~Near-Term~~ analysis. The MDWG creates new steady-state and dynamic models annually and updates these models throughout the year.

3.3 Model Development & Analysis

3.3.1 Model Development

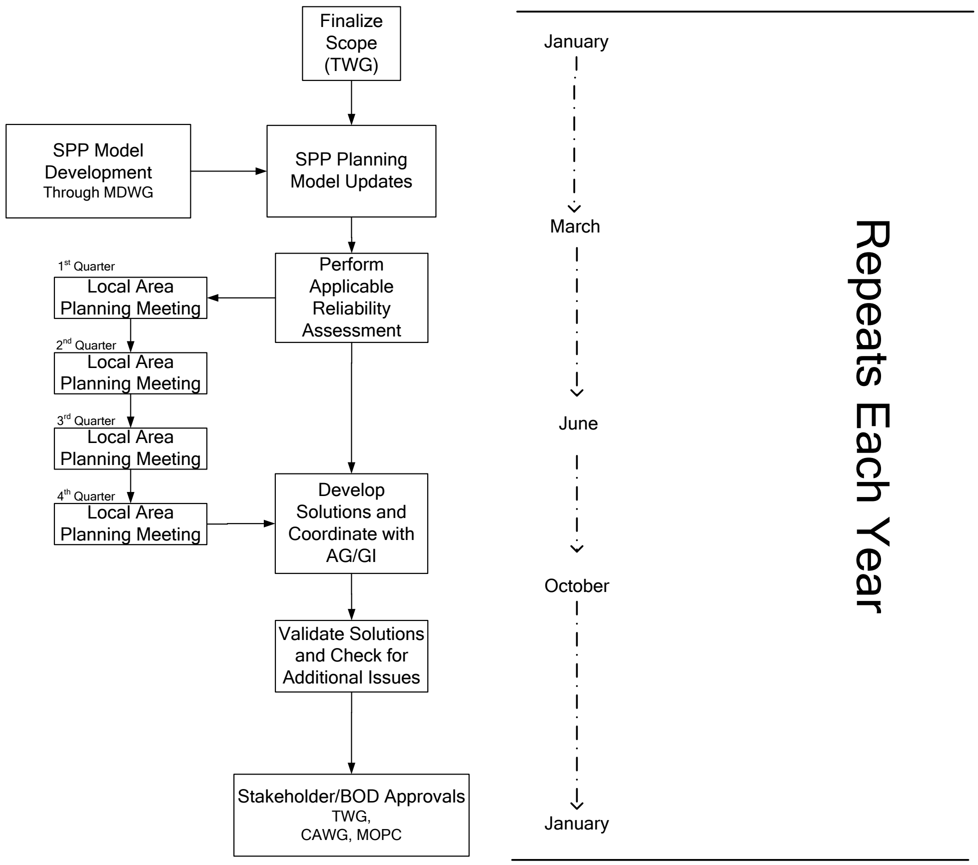
3.3.1.1 Inter~~-R~~regional Coordination

SPP is responsible for coordinating transmission planning with each neighboring interconnected system. SPP will coordinate any activities and studies based on the agreements listed in Addendum 1 to Attachment O of the OATT. As part of the inter-regional coordination process, SPP will share system plans with neighboring entities and identify system enhancements on the seams.

3.3.1.2 Modeling Process

Planning within SPP is a collaborative process with Transmission Owners, users, and other stakeholders. Thee~~is~~ ITPNT~~Near-Term~~ Assessment process requires that Transmission Owners continue to develop expansion plans to meet the needs of their systems. At the same time, SPP assesses its system for the ability to meet applicable reliability standards and address stakeholder concerns, including those of regulators.

The 12-month ITPNT~~Near-Term~~ planning process focuses on the system's reliability needs and the commercial and market needs for all the stakeholders in the SPP footprint. This process was developed by SPP staff in conjunction with the TWG. The process is shown in the figure below.



Details regarding key assumptions, models, project data, specific tasks, outstanding issues, progress reports, maps, and study results are available on the SPP web site.

The steady-state model building begins in January and starts with the SPP MDWG spring case topology of that same year of the study. Transmission owners and balancing authorities provide generation dispatch and load information for the years to be studied.

Transmission owners enter network changes into MOD at which time the type and status of the network upgrades is identified. The type and status of MOD projects identify into which SPP model set the network change will be entered. Appendix A of this manual provides the listing of the description of the types and statuses.

Included in the ITPNT~~Near-Term~~ Assessment models (i.e. ITP Reliability models) are all topology changes that have a NTC from SPP except projects that have been requested to be removed from the base ITP reliability models. These exceptions must go through a stakeholder review process as described below:

1) Stakeholder requests NTC project be removed from the base ITP reliability model along with the reason why they would like the project excluded and re-evaluated in the ITPNT ~~Near Term~~.
2) If SPP Tariff Study Group identifies any Transmission Service that may be dependent upon the project, SPP Planning Group would identify any concerns in connection with removing the project from the base model and re-evaluating the need
3) The list of NTC projects to be re-evaluated is given to stakeholders for a 15 day review and comment window.

Generation interconnection facilities are included in the ITP reliability models if they have an executed Interconnection Agreement (IA) and not on suspension. Generation capacity does not get included in the assessment until there is an executed transmission service agreement.

Comment [S28]: Discuss

Confirmed Long Term Firm transmission service is included in the ITP reliability models. In addition to Confirmed Firm service mentioned above, the following will also be included: 1) transactions to make generation and load match. ; 2) proposed generation stations and associated service from new generation that has a high probability of going into service; i.e. If a planned generating resource does not have a TSR filed service agreement but does have both a high probability of going into service and a high probability of obtaining an executed transmission service agreement, that new generator's service can be included in the SPP regional reliability planning models if it meets all of the following requirements:

- A formal request has been sent to SPP[12] requesting the generation capacity be included into the ITP;
- The generating resource has a FERC-filed IA not on suspension or FERC-filed interim IA;
- The generating resource has acquired the funding for major equipment;
- The generating resource has entered the Aggregate Study or equivalent; Transmission Owner transmission service study publicly posted on OASIS and has a completed facility study that is waiting for final results without unmitigated third party impacts[13];
- The generating resource has acquired air and environmental permits where applicable;
- The generating resource has started construction with major equipment procurement contracts awarded; and
- The generating resource's unit(s) must be dispatchable and committable.
  - If a generating resource does not meet all the above requirements, a formal request for generation capacity to be included in the ITPNT ~~Near-Term~~ can be made to TWG on a case by case basis.
    - TWG will take into account the following, but not limited to, additional points:
      - An exception to include service from generation that will defer transmission expenditure(s) without a TSR filed service agreement and without a filed IA or a filed interim IA that have a high probability of going into service and also getting both an executed IA and an executed transmission service agreement must meet all of the below requirements:
      - A formal request has been sent to SPP[14] requesting the generation capacity be included into the ITP. The request should identify which transmission upgrades will be deferred

[12] Email sent to planning@spp.org
[13] Eliminates generators that may drop out as a result of changes in study results

- The generating resource has a mitigation plan for the deferred transmission upgrades until it makes a financial commitment to perform the upgrades
- A Definitive Interconnection System Impact Study Agreement (DISIS) for the generating resource has been executed, an interim IA has been requested when the DISIS was posted and a final IA was FERC filed when applicable
- An RFP for the generating resource has been awarded, if applicable

If there is a shortfall between interchange, generation, and load or issues regarding reactive power support for an area in later years of the ITPNT~~Near-Term~~ Assessment analysis after the inclusion of all the above processes the following steps will be used sequentially to address system deficiencies[14]:

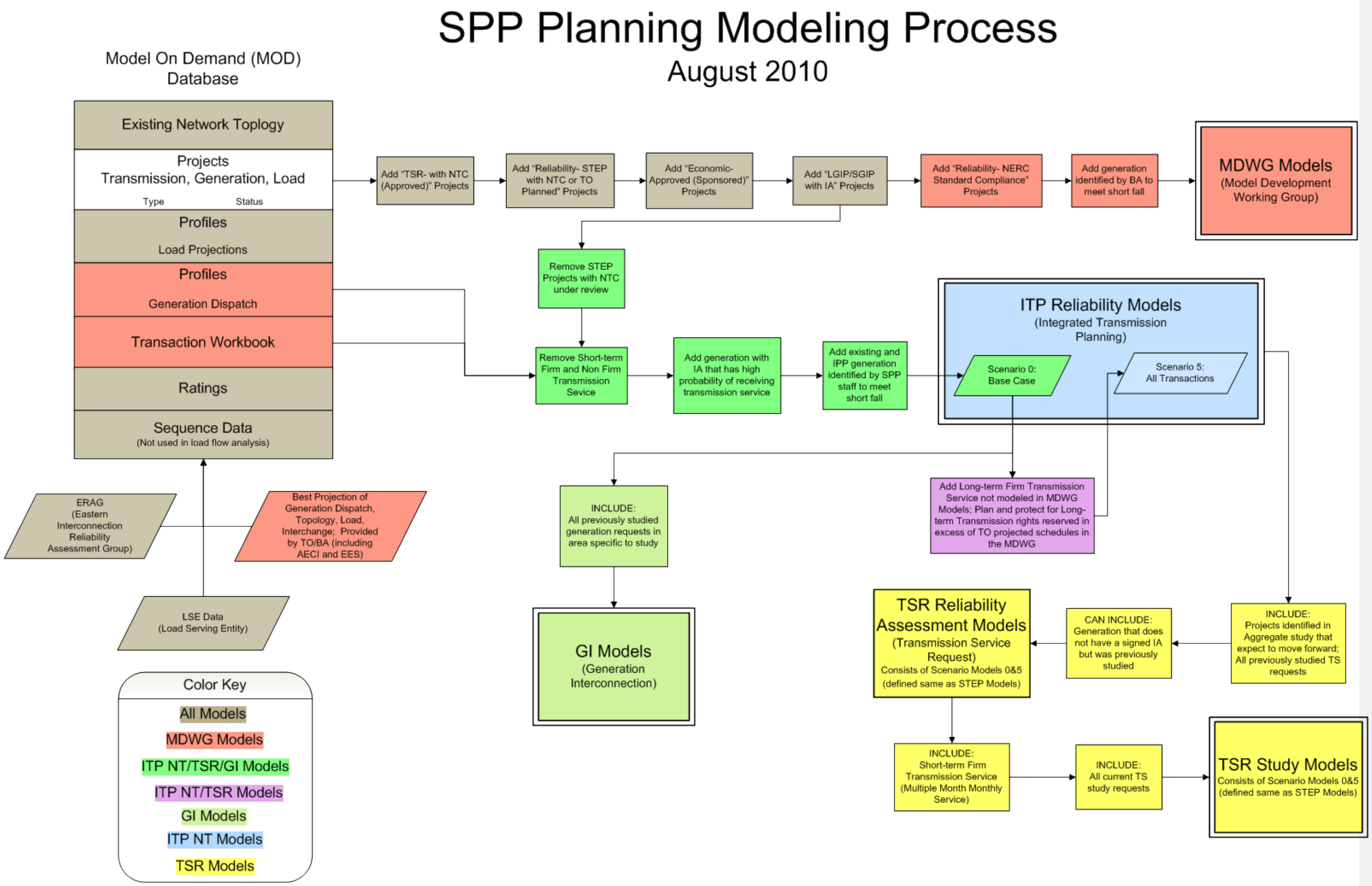
1) Exhaust the dispatchable generation of the network customer,
2) Exhaust the Independent Power Producers (IPP) dispatchable generation in the same model area,
3) Dispatch the remaining unused, dispatchable generation on a pro rata basis within SPP footprint.
4) When all other options have been exhausted, including the aforementioned formal request process, include generation resources from the most recently approved ITP10 resource plan. The addition of these ITP10 generation resources will not automatically generate NTCs.

If an ITP10 generation resource is being utilized solely for reactive support, then it will be dispatched to a minimum amount in order to remedy the situation as needed. If additional voltage support is needed, the addition of static or dynamic resources may be required and used to solve cases as needed. The addition of these devices will not automatically generate NTCs.

SPP uses scenarios to evaluate reliability. The number of scenarios is determined each year and approved by the TWG.

[14] Non-dispatchable wind generation or other generation with operating restrictions or forecasted projections shall not be used.

Below is a flow chart of the SPP planning modeling process.



3.3.2 Modeling Analysis

3.3.2.1 Transmission Operating Guides

SPP uses Transmission Operating Guides in its ITPNT~~Near-Term~~ Assessment analysis. Appendix B of this manual contains the SPP procedure to address use of operating guides in planning studies.

3.3.2.2 Assessment Methodology

Each year the assessment's scope is developed and approved by the TWG. The scope will contain following:

- The years and seasons to be modeled
- Treatment of upgrades in the models
- Scenario cases to be evaluated
- Description of the contingency analysis and monitored facilities
- Any new special conditions that are modeled or evaluated for the study
- Stability analysis may be performed using 5-6 year models[15]

3.3.2.3 Solution Development

After SPP performs the reliability assessment identifying the bulk power problems, SPP will present and solicit Transmission Owners and stakeholders for transmission solutions to those reliability problems. SPP solicits stakeholders in several forums including the planning summits and working group meetings. After receiving feedback from stakeholders, SPP will take current Aggregate Studies and Generation Interconnection studies into consideration to develop and validate the best regional solution for problems. Then SPP shares the proposed solutions with the members and stakeholders at various stakeholder meetings asking for additional feedback on the solutions. This process repeats for several iterations as staff refines the solutions in a set timeline.

Comment [WLS29]: Need to update this section to reflect Order No. 1000 process

Throughout the process, alternative solutions are proposed by stakeholders. SPP analyzes those alternatives in accordance with Section III.8 of Attachment O of the OATT.

3.4 Order 1000 Process

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[15] This stability analysis will be performed once per ITP cycle (i.e. every three years).

~~3.~~4 Under the Order 1000 Process, models will be extremely important such that submitted solutions really address issues on the SPP system. Models for the ITP will be released by SPP for a review by stakeholders with feedback provided to SPP on corrections to the models and possible enhancements. There may be 1 or more such reviews needed to address modeling issues as determined by SPP Staff. SPP will issue a final ITP model identifying key congestion issues and issues needed to be solved during the ITP process. Stakeholder will then have 30 days after the release of the final model to develop solutions as described in the DPP process and business practice. SPP will review the solutions in the course of the ITP solution development and select those DPP or solutions (non-DPP) that best provide the economic and reliability needs of the system. Upon completion of the preliminary results, a Transmission Planning Summit will be held to review the solutions for stakeholder feedback. Changes may be made based upon feedback from stakeholders. A final ITP report and plan will be presented to MOPC, Members Committee and Board for approval. Upon approval those projects that meet the Order 1000 requirements will be issued RFP's for competitive bidding purposes in compliance with the SPP OATT and business practices. The RFP evaluations will include award of any DPP points to stakeholders that have recommended solutions used by SPP staff for the ITP.

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3.5 Deliverables

The deliverable for the ITPNT ~~Near-Term~~ Assessment will be a list of 69 kV+ projects that would maintain the reliability of the SPP Region in the near term horizon.

In developing the annual STEP report, staff will include a section about the annual ITPNT~~Near-Term~~ Assessment. This section will summarize the regional, sub-regional and local transmission needs of the SPP Region in the near term horizon which is assessed to meet SPP's reliability needs. The ITPNT~~Near-Term~~ Assessment results will also contain a list of at least the following upgrades:

- Regional upgrades required to maintain reliability in accordance with the NERC Reliability Standards and SPP Criteria in the near term horizon;
- Zonal upgrades required to maintain reliability in accordance with more stringent individual Transmission Owner planning criteria in the near term horizon; and
- Inter-regional upgrades developed with neighboring Transmission Providers to meet inter-regional needs, including results from the coordinated system plans, in the near term horizon.

Throughout the ITPNT~~Near-Term~~ Assessment process, SPP shares, discusses, and refines proposed solutions with stakeholders. The solutions are finalized in the annual STEP report.

4 Issuance of NTCs ~~and ATPs~~

Once the ITP is reviewed by the MOPC and approved by the BOD, staff will issue NTC letters for approved projects in the 20-Year, ITP10~~-Year~~, and ITPNT~~Near-Term~~ Assessments which are within the financial window as approved by the BOD. The NTC is sent to the incumbent

Comment [WM30]: My understanding is that the ITP20 does not produce NTC's. Am I misunderstanding? If not, we need to delete ITP20 here.

Transmission Owner(s) for the project. ~~All other projects approved by the BOD in the ITP will receive an Authorization to Plan (ATP). All of the projects for which an ATP is issued will be posted on the SPP website. ATPS will be included in all future Aggregate Study and Generation Interconnection study models.~~

Comment [WLS31]: Needs to be updated to reflect the Order No. 1000 process

5 Reporting Requirements

Staff will inform the appropriate working groups throughout the year of the progress of the ITP assessments. SPP will also report on these assessments in its annual STEP report which will include a list of projects from those assessments. The STEP report will be presented to the BOD for approval.

5.1 Stakeholder Review Process

To show transparency in its planning processes, SPP holds planning summits that allow stakeholders opportunity to engage in, develop, and review SPP's on-going planning assessments and their results. SPP also has working groups meetings as another forum for stakeholders to become involved in SPP planning studies.

APPENDICES

6 Acronyms and Term Definitions

1. AECI – Associated Electric Cooperative, Inc.
2. APC – Adjusted Production Cost: APC is a dollar value calculated by adding the cost of producing energy to the cost of energy purchases and subtracting the revenue from energy sales
3. ATP – Authorization to Plan: The ATP is a status given to a project which indicates that the BOD has approved the project in the SPP ITP and it has not yet been issued an NTC because it is outside of the NTC financial commitment window.
4. BOD – SPP Board of Directors/Members Committee: The BOD is the governing body of SPP

~~4.~~5. DPP- Detailed Project Proposal

~~5.~~6. EHV – Extra High Voltage: In this document EHV refers to transmission at 300 kV or greater

~~6.~~7. ERCOT – Electric Reliability Council of Texas

~~7.~~8. ESWG – Economic Studies Working Group: The ESWG reports to the MOPC and advises and assists SPP staff, various working groups and task forces in the development and evaluation principles for economic studies

9. FERC – Federal Energy Regulatory Commission

~~8.~~10. IRP – Integrated Resource Plan: A Utilities resource plan that serves projected load.

~~9.~~11. ITP – Integrated Transmission Plan: The ITP is SPP's approach to planning transmission needed to maintain reliability, provide economic benefits, and achieve public policy goals to the SPP region in both the near and long-term

~~10.~~12. LMP – Locational Marginal Price: Also known as nodal pricing, the LMP is the incremental cost to the system that would result from one additional unit of energy that is demanded at a particular node

~~11.~~13. MAPP – Mid-Continent Area Power Pool

~~12.~~14. MDWG – Model Development Working Group: The MDWG is responsible for maintenance of an annual series of transmission planning models (powerflow and short circuit models and associated stability database) which represent the current and planned electric network of SPP

~~13.~~15. MISO – Midwest Independent Transmission System Operator

~~14.~~16. MOPC – Markets and Operations Policy Committee

~~15.~~17. MTF – Metrics Task Force: The MTF is a task force created by the ESWG to create a list of metrics for the ESWG to consider for use in evaluating projects in the ITP

~~16.~~18. NERC – North American Electric Reliability Corporation

~~17.~~19. NERC TPL – NERC Transmission Planning Standards

~~18.~~20. NTC – Notification to Construct: The NTC is a formal SPP document specifying approval of and notification to build specific network upgrades with specified need dates for commercial operation

~~19.~~21. OATT – Open Access Transmission Tariff: SPP's transmission tariff as posted on SPP's website

~~20.~~22. PJM – PJM Interconnection

~~21.~~23. PTDF – Power Transfer Distribution Factor: A PTDF is the percentage of power transfer flowing through a facility(ies) for a particular transfer when there are no contingencies.

~~22.~~24. ROW – Right-of-Way: The ROW identifies the strip of land which is needed for transmission purposes

~~23.~~25. RSC – Regional State Committee: The SPP RSC provides collective state regulatory agency input on matters of regional importance related to the development and operation of bulk electric transmission

~~24.~~26. SERC – SERC Reliability Corporation
~~25.~~27. SPP – Southwest Power Pool, Inc.: SPP is a Regional Transmission Organization
~~26.~~28. SPPT – Synergistic Planning Project Team (SPPT): The SPPT is a team which was created to address comprehensive transmission planning processes and allocation of transmission costs associated with both existing and strategic issues including transmission service, generator interconnection, Extra High Voltage (EHV) inter-regional transmission, wind integration, etc
~~27.~~29. STEP – SPP Transmission Expansion Plan: The STEP is an annual plan which summarizes activities that impact future development of the SPP transmission grid. The STEP includes projects approved in the ITP, 10 Year Reliability, Priority Projects, Aggregate Study, Generation Interconnection, etc.
~~28.~~30. TLR – Transmission Loading Relief: A TLR is a process which is used to reduce loading on lines which are at risk for an overload
~~29.~~31. TWG – Transmission Working Group: The TWG reports to the MOPC and is responsible for planning criteria to evaluate transmission additions, seasonal ATC calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations
~~30.~~32. WECC – Western Electricity Coordinating Council

7 Benefit Metrics

The section below provides further definition and commentary on each of the 10 benefit metrics that will be considered in the ITP planning process when evaluating potential transmission projects.

1. Adjusted Production Cost (APC) Savings

   a. Definition:

      The standard APC metric measures 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 metric quantifies the monetary cost associated with fuel costs, generation dispatch, most grid congestion, energy purchases, energy sales, and other factors that directly relate to energy production by generating resources in the SPP footprint. The APC calculation also captures cost savings associated with reducing emissions and ancillary service requirements.

   b. Measurement/Monetization:

      APC estimates are usually performed for weather-normalized peak load (i.e., 50/50 peak load).
      The APC for an area is determined using a production cost modeling tool that captures hourly commitment and dispatch profiles for one simulation year. The hourly calculation accounts for:

Production Costs:	The fuel and non-fuel variable O&M costs of utility-owned or cost-of-service-contracted generation.
Revenue from Sales:	MWh Sold by Utility x Generation-Weighted Avg. Zonal Gen. LMP
Cost of Purchases:	MW Purchased by Utility x Load-Weighted Avg. Zonal Load LMP

      The APC benefit is then based upon the difference in the production cost simulations for the base case and the change case.

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c. Allocation:

The APC savings are calculated in the production cost simulations on a zonal basis.

1. Reduction of Emission Rates and Values

a. Definition:

Allowance prices for SO_2, NO_x, and CO_2 emissions are used as inputs to the production cost model simulations and are specific to the various generating technologies modeled. Transmission projects can relieve grid congestion and change generation dispatch, resulting in cost savings associated with reductions to SO_2, NO_x, and CO_2 emissions.

b. Measurement/Monetization:

The APC calculation captures the cost savings associated with reduced SO_2, NO_x, and CO_2 emissions, as scoped for each particular economic study, through the assumed allowance price for these emissions.
The allowance market dynamics that take place separately from events in the energy market are not considered in this 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.

c. Allocation:

The reduction of emission rates and values is captured in the APC, which is calculated on a zonal basis.

2. Savings due to Lower Ancillary Service Needs and Production Costs

a. Definition:

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, but generally take a static approach to modeling sub-hourly 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 either (1) a reduction in needed A/S quantities or (2) a reduction in the cost of procuring that quantity.

- Quantity Impact: At present, SPP A/S needs are determined according to the SPP Market Protocols with input from SPP staff. Findings from renewable integration studies and analyses suggest that improved transmission topology can contribute to reducing system A/S needs, which tend to increase as a function of renewable generation penetration. Therefore, system-wide A/S needs could be calculated as a function of transmission capacity and transfer capability among zones.
- Procurement Cost Impact: Conceptually, the cost of providing A/S should be captured in the APC metric if the simulation software can accurately capture and simulate A/S requirements and their deployment.

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b. Measurement/Monetization:

The quantity impact will be captured as the formulaic determination of A/S needs evolves and transmission overlay begins to directly impact zonal or system-wide A/S needs. At such a point, the benefit from incremental transmission capabilities can be directly measured by calculating A/S needs in production cost simulations for the base and change cases.

Similarly, improved production cost modeling of sub-hourly A/S procurement and deployment can enable the measurement of the cost impacts directly within the APC calculations.

Monetization of the quantity and cost benefits will be reflected in the overall APC savings. The production cost simulation will be conducted using the initial A/S needs for the base case and the same (or possibly reduced) 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 ancillary services).

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c. Allocation:

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Benefits will be calculated in the production cost simulations and will be assigned to the SPP region as a whole and re-allocated to each of the zones on a load ratio share basis.

3. Avoided or Delayed Reliability Projects

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a. Definition:

Potential reliability upgrades are reviewed to determine if an upgrade with a greater economic or policy benefit could defer or replace an identified reliability solution. If such a larger project with economic or public policy benefits is pursued, the costs associated with the reliability projects that are replaced by the larger project represent the avoided or delayed reliability project benefit of the larger project.

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b. Measurement/Monetization:

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The methodology to determine which reliability projects were replaced with economic projects follows these steps:

i. Reliability need identified.
ii. Reliability mitigation provided and tested to ensure successful mitigation.
iii. Congestion in the system identified.
iv. Congestion near and related to reliability needs paired to compare alternative projects.
v. The value of resolving the congestion with an economic project that also mitigated the reliability need is measured and compared with the difference in costs between the projects.
vi. Where cost effective, the economic project was selected to mitigate the reliability need and relieve the congestion.

The avoided (or delayed) reliability project benefit is then captured as the avoided cost of delaying or canceling previously approved reliability projects.

c. Allocation:

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

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4. Capacity Cost Savings due to Reduced On-Peak Transmission Losses

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a. Definition:

This metric captures the value of generation capacity that may no longer be required due to a reduction in losses during the system peak.

b. Measurement/Monetization:

These capital savings will be calculated by applying the estimated net Cost of New Entry (CONE) to the reduction in installed capacity requirements. The net CONE is the difference between the annualized CONE and the 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 includes the levelized 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 other comparable public source. The following sources may be used to estimate the average annual energy and ancillary service profits for a combustion turbine:

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- Historical market revenues net of fuel and variable non-fuel operating costs for combustion turbines in SPP or similar market(s).

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- 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).

Monetization of the capacity cost savings will be calculated using the savings in capital attributed to the corresponding MW reduction in installed capacity requirements.

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c. Allocation:

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The capacity cost savings calculations will be performed zone-by-zone and allocated accordingly.

5. Assumed Benefit of Mandated Reliability Projects

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a. Definition:

In evaluating projects within the portfolio that would be built to meet transmission reliability standards (i.e. classified as a 'reliability project' as defined in this manual), the benefit of fixing the reliability violation should be assumed to be equal to its cost. This benefit will be mutually exclusive from any other reliability benefit applied to those same projects.

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b. Measurement/Monetization:

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Mandated reliability project benefits are set equal to costs with other economic benefits, such as APC savings, being additive (or subtractive in the case of losses). It is important to note that any transmission project with APC savings that result in a benefit-to-cost (B/C) ratio greater than 1.0 will be considered an 'economic project' with no additive reliability benefit, even if it fixes a reliability violation.

c. Allocation:

These benefits will be allocated using a hybrid approach that utilizes Load Ratio Share and System Reconfiguration, depending upon project size. The System Reconfiguration approach looks at the flows on all lines in the SPP system, both with and without the reliability upgrade. All lines with an increase in flow after the reliability upgrade is placed on outage are identified as having flows relieved by the reliability upgrade. The allocation of benefits is then based upon the increase in line flows across the system when the upgrade is on outage. The allocation will vary as follows, based upon the project size:

i. If the project is < 100 kV, allocate 100% based upon System Reconfiguration.
ii. If the project is 100-300 kV, allocate 2/3 System Reconfiguration, 1/3 Load Ratio Share.
iii. If the project is > 300 kV, allocate 1/3 System Reconfiguration, 2/3 Load Ratio Share.

6. Public Policy Benefits

a. Definition:

This metric captures the value of meeting public policy goals or mandates 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 to do so.

b. Measurement/Monetization:

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 implementing a public policy. Therefore, the objective is finding the most cost effective method in meeting that goal, and the benefit in achieving the goal or mandate is assumed to be equal to the project cost. It is important to note that any transmission project with APC savings that result in a benefit-to-cost (B/C) ratio greater than 1.0 will be considered an 'economic project' with no additive public policy benefit.

c. Allocation:

Benefits will be allocated based upon the share of unmet renewable mandates or goals and only to zone(s) within the state(s) driving the public policy project(s).

7. Increased Wheeling Through and Out Revenues

a. Definition:

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Increasing ATC with a neighboring region improves import and export opportunities outside of the footprint. Increasing inter-regional transmission capacity that causes an increase in through and out transactions will also increase SPP wheeling revenues. While the energy revenue benefit of increased exports is captured by the APC metric, the APC metric does not capture any increases in wheeling out or wheeling through revenues associated with increased transfer capability. These increased wheeling revenues are a benefit as they will offset part of the transmission projects' revenue requirements.

b. Measurement/Monetization:

The quantity impact will be determined by calculating the incremental long-term wheeling service that SPP was able to sell due to upgrades and using that historical ratio to calculate wheeling MW and revenues for export-ATC changes from new projects in the future. Reduced ratios, or scaling factors, will be considered based upon additional analyses for very large future ATC increases.

Wheeling revenue calculations as proposed here will not result in double-counting of benefits with respect to APC calculations. The reason is that in the APC methodology, imports are priced at the importing region's internal load LMP, while exports are valued at the exporting region's internal generation LMP. As a result, even if part of the difference is payable as a wheeling charge, the revenues collected are not counted in either the exporting or importing region's APC.

An average wheeling charge will be utilized to monetize the value of increased wheeling through and out transactions. The average SPP wheeling charge will be calculated by using the actual wheeling revenues divided by the MWh exports scheduled the previous year.

c. Allocation:

These benefits will be allocated according to the methodology in the Tariff for allocating wheeling revenues.

8. Marginal Energy Losses Benefit

a. Definition:

This metric captures the reduced MWh quantity of transmission losses that results from transmission expansions. Standard production cost simulations used to estimate the APC benefits 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. However, the production cost savings due to such energy loss reductions can be estimated through post-processing simulation results.

b. Measurement/Monetization:

The benefits of the reduced MWh losses will be calculated post-processing by capturing the Marginal Loss Component (MLC) for the LMP to calculate loss factors. The actual loss-related energy cost savings will be reduced by the energy cost

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savings already in the APC to arrive at the marginal energy cost savings not captured in the simulations.

c. Allocation:

The marginal energy loss calculations will be performed zone-by-zone and allocated accordingly.

9. Mitigation of Transmission Outage Costs

a. Definition:

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. Thus, the benefit of reducing this additional congestion is 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.

b. Measurement/Monetization:

To measure the savings in transmission outage costs due to transmission expansion, the production cost modeling analysis will be modified to reflect a realistic level of transmission outages using a subset of historical transmission outage events. The benefits will be calculated as the difference between 1) the APC savings due to the transmission upgrades for a system considering transmission outages and 2) the standard APC savings due to the transmission upgrades which are calculated for a system without any transmission outages.

c. Allocation:

These benefits will be calculated on an SPP-wide basis and allocated to zones based on the load ratio share.

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