Southwest Power Pool

Southwest Power Pool

TRANSMISSION WORKING GROUP MEETING

September 13, 2010

Net conference

• M I N U T E S •

Agenda Item 1 – Administrative Items

TWG Chair Noman Williams called the meeting to order at 1:00 p.m. The following people were in attendance: (Attachment 1 – Proxies)

TWG Members

Noman Williams, Sunflower Electric Power Corp
John Chamberlin, City Utilities of Springfield
Angela Easton, Calpine Energy Services
Jason Fortik, Lincoln Electric System
Ronnie Frizzell, Arkansas Electric Cooperative
Travis Hyde, Oklahoma Gas and Electric
Dan Lenihan, Omaha Public Power District
Sam McGarrah, Empire District Electric
Nathan McNeil, Midwest Energy
Matt McGee, American Electric Power
John Payne, Kansas Electric Power Cooperative
Jason Shook, GDS Associates for ETEC
Don Taylor, Westar Energy
Mitch Williams, Western Farmers Electric Coop
Brian Wilson for Harold Wyble, Kansas City Power & Light

Other Stakeholders and Staff

Syed Ahmad, FERC
Roy Boyer
Charles Cates, SPP Staff
Bruce Cude, Southwestern Public Service Company
Tom DeBaun, Kansas Corporate Commission
Tony Gott, Associated Electric Cooperative
Rachel Hulett, SPP Staff
Bob Lux, SPP Staff
Kristen Rodriguez
Al Tamimi, Sunflower Electric Power Corp
Keith Tynes, SPP Staff

Agenda Item 2 – ITP Manual

The group reviewed and revised the remaining portions of the ITP manual under TWG purview (Attachment 2 – ITP Manual). The TWG noted MDWG is currently revising Appendix A of the manual and asked that the Authorizations to Plan (ATPs) to be included in the model building process.

Don Taylor, Westar Energy, motioned to approve the ITP Manual including all TWG edits Ronnie Frizzell seconded the motion which was approved unopposed.

RTWG will review the ITP manual prior to the October MOPC meeting to ensure its consistency with the Tariff. It was noted that any RTWG changes to the manual would come back to TWG.

Agenda Item 3 – Adjournment

The next meeting is October 4 in Dallas with ESWG.

With no further business, Noman Williams adjourned the meeting at 2:59 p.m.

Respectfully Submitted,

Rachel Hulett
TWG Secretary

KCPL, Brian Wilson for Harold Wyble

From: Wyble Harold [mailto:Harold.Wyble@kcpl.com]
Sent: Wednesday, September 08, 2010 1:33 PM
To: Rachel Hulett; 'Williams, Noman'
Cc: Wilson, Brian
Subject: TWG 9/13/10 Net Conference

Brian Wilson will have my proxy for this net conference.

Draft

Integrated Transmission Planning Manual

MAINTAINED BY
SPP Engineering

PUBLISHED: [Click **here** and type **MM/DD/YYYY**]
LATEST REVISION: 09/13/2010

you can move or resize this text box by clicking on the edge and dragging

Southwest Power Pool

Table of Contents

I. Introduction

A. Acronyms and 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
5. EHV – Extra High Voltage: In this document EHV refers to transmission at 345kV or greater
6. 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
7. FERC – Federal Energy Regulatory Commission
8. 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
9. 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
10. MAPP – Mid-Continent Area Power Pool
11. 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
12. MISO – Midwest Independent System Operator
13. MOPC – Markets and Operations Policy Committee:
14. 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
15. NERC – North American Electric Reliability Corporation
16. NERC TPL – NERC Transmission Planning Standards
17. 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
18. OATT – Open Access Transmission Tariff: SPP's transmission tariff as posted on SPP's website
19. PJM – PJM Interconnection
20. 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
21. ROW – Right-of-Way: The ROW identifies the strip of land which is needed for transmission purposes
22. 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
23. SERC – SERC Reliability Corporation
24. SPP – Southwest Power Pool, Inc.: SPP is a Regional Transmission Organization

Deleted: amount

Deleted: that will

Deleted: given a particular source and sink

Deleted: based on the impedance of the system

25. 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
26. STEP – SPP Transmission Expansion Plan: The STEP is an annual plan which summarizes activities that impact future development of the SPP transmission grid
27. TLR – Transmission Loading Relief: A TLR is a process which is used to reduce loading on lines which are at risk for an overload
28. 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

B. Purpose

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

C. ITP Overview

The Integrated Transmission Plan (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. The ITP 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 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 is an iterative three-year process that includes 20-Year[1], 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 creates synergies by integrating existing SPP activities: 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 works in concert with SPP's existing sub-regional planning stakeholder process, and parallels the NERC TPL Reliability Standards compliance process.

The Economic Studies Working Group (ESWG) was also formed in conjunction with the development of the ITP and will maintain the processes and metrics on an ongoing basis for qualifying and quantifying the transmission projects for the 20-Year and 10-Year Assessments.

[1] 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 maintain the process on an ongoing basis for qualifying and quantifying the transmission projects for the Near-Term Assessment.

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

D. <u>Background</u>

In January of 2009 the BOD created the 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 the organization adopt a new set of planning principles; develop and implement an ITP; 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.[2]

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

- Focus on regional needs, while considering local needs as well; long range plans (both 20-year and 10-year) are to be updated every three years while near-term 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 and the Electric Reliability Council of Texas grids in the future.
- Incorporate 20-year physical modeling and 40-year financial analysis timeframe.
- Better position SPP to proactively prepare for and respond to national priorities while providing flexibility to adjust expansion plans.

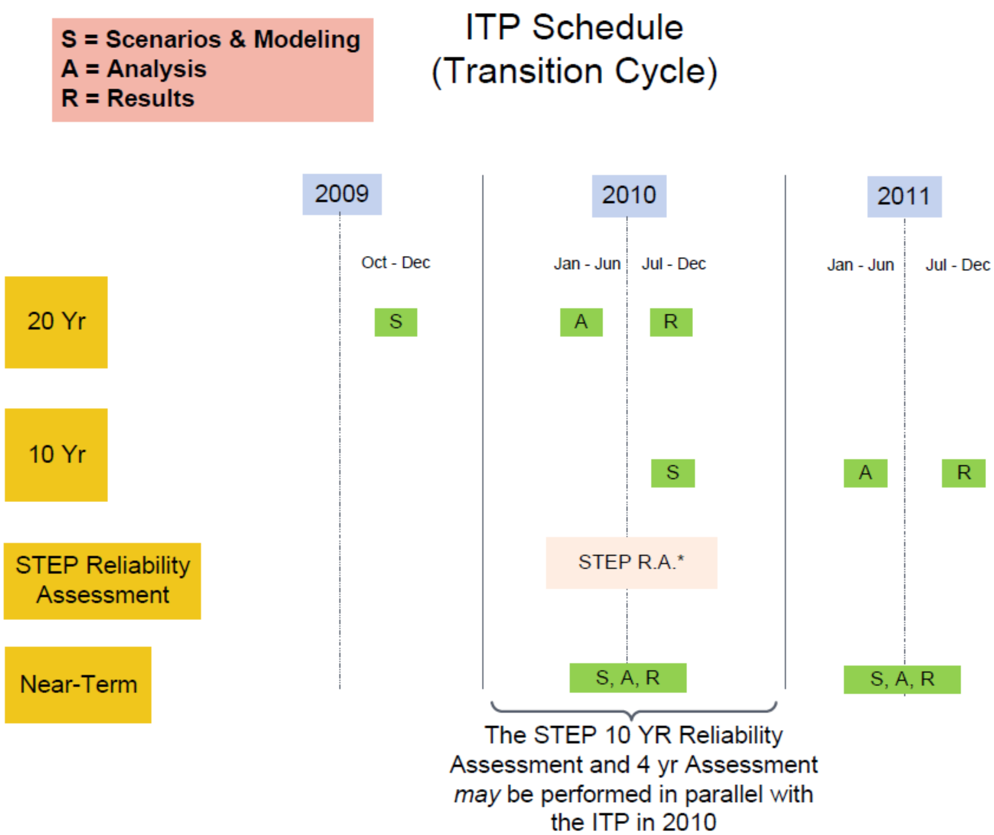
SPP began performing its planning duties in accordance with the ITP process in January of 2010, shortening the 20-year Assessment from an 18 month process to a 12 month process.

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

II. Transmission Planning Upgrade Process

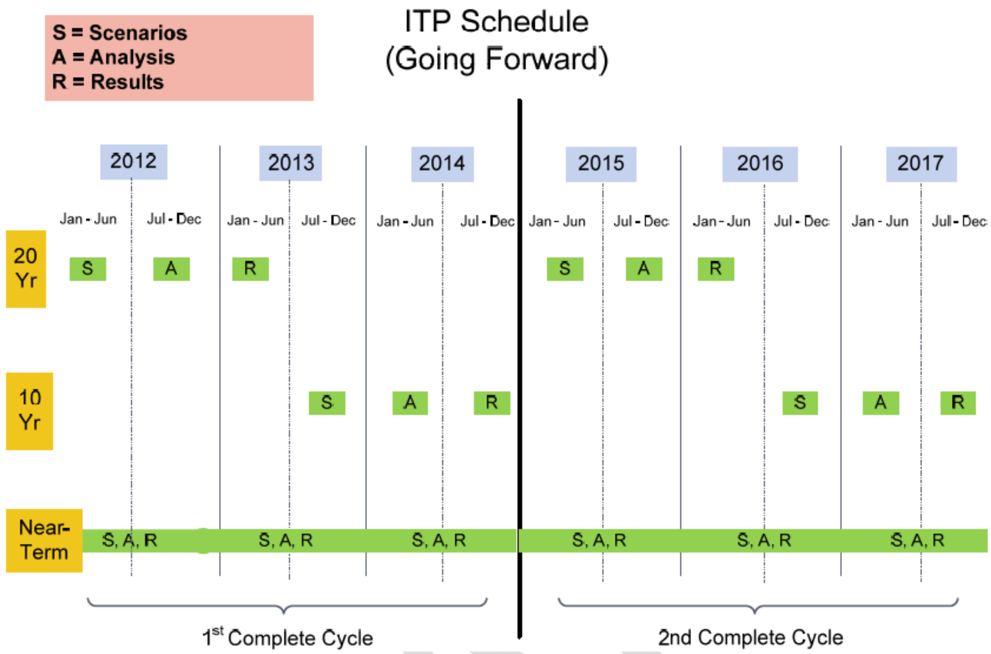
A. ITP Process & Schedule

Beginning in November 2009, SPP began working with stakeholders to develop the scenarios for the 20-Year Assessment with results to be presented in January 2011.[3] The 10-Year and Near-Term Assessments will be performed in 2011, with results presented in January 2012.



Moving forward, evaluation of future scenarios that may affect the ITP will occur during the first half of 2012 for the 20-Year Assessment and during the second half of 2013 for the 10-Year Assessment. The 20-Year Assessment will begin in year one and be completed in year two. The 10-Year Assessment will begin during year two and be completed in year three. The Near-Term Assessment will be performed each year to ensure reliability and to incorporate local planning requirements.

[3] ITP Final Process Document - http://www.spp.org/publications/ITP_Process_Final_20091029.pdf



The ITP process is an iterative three-year component of the STEP that includes 20-Year, 10-Year, and Near-Term Assessments. Each of these assessments targets a reasonable balance between long-term transmission investment and customer congestion costs. 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.[4]

B. Cost-Effective Analysis & Robustness Evaluation

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

Cost-effective analysis is a form of economic analysis that compares the relative costs and outcomes (effects) of two or more courses of action. In effect, the benefits side of the equation is held constant at some pre-determined standard of service, and various options for providing

[4] 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.

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 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 increment cost and benefits. Metrics of robustness may be quantitative and/or qualitative.

1. Development of Assumptions

Assumptions used in the ITP will be developed during the first and second year of each three-year ITP cycle for the 20-Year and 10-Year Assessments, respectively, and annually for the Near-Term Assessment. Assumptions will include those needed for economic studies, reliability studies, and futures development.

The ESWG will guide the development of the assumptions used in the economic assessments and the TWG will guide the development of the assumptions for the reliability impact assessments.

Once developed, staff will present the assumptions within an ITP study scope document for approval by the ESWG, TWG, and MOPC (with review from the RSC)as appropriate. The scope of each assessment will be revisited at the beginning of each three-year cycle of the ITP.

In addition to any assumptions identified by the ESWG and TWG, the analysis must also encompass a plausible collection of assumptions for each specific model run including, but not limited to, varying levels of the following:

- Renewable Electricity Standards
- Load growth
- Demand response
- Energy efficiency
- Fuel prices
- Environmental and governmental regulations
- Resource (e.g. generation, transmission, smart grid) Technology
- Public Policy

C. Recommendations and Results

A list of projects from the assessments performed throughout the year will be presented to stakeholders for discussion and review at an SPP planning summit. Staff will then make any necessary adjustments to the ITP based on stakeholder feedback. The final plan will be included as a component of the STEP report and presented to the MOPC and the BOD.

III. Twenty-Year Integrated Transmission Planning

A. Purpose

The first phase of the ITP process is the 20-Year Assessment[1] which will be used to develop an EHV backbone network. The value-based planning assessment will use a diverse array of power system and economic analysis tools to thoroughly study the transmission system to identify cost-effective and robust backbone projects needed to provide a grid flexible enough to reasonably accommodate possible changes characterized by the various scenarios. Because the degree to which the power transmission landscape will change over this time frame is not currently known, transmission system expansion will be 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 as a result of the 20-Year Assessment will be expected to provide benefits to the region across multiple scenarios.

B. Futures Evaluation

Due to the uncertainties involved in forecasting future system conditions, a number of diverse futures or scenarios will be considered that take into account multiple variables. Consideration of multiple futures or scenarios will provide for a transmission expansion plan that will evolve 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 will change the way the electric grid is utilized. The futures are defined by the SPP Strategic Planning Committee (SPC). Based on direction of the SPC, the ESWG would further develop the assumptions and the inputs for the futures.

C. Data Requirements & Assumptions

Each stakeholder will have the opportunity to submit data and review their individual data which is being used for the study. The original data set to be used in the model will be provided by the vendor retained by SPP. That data is then reviewed by the stakeholders who can then provide specific updates to non-sensitive data. Data pertaining to unit costs and heat rate will not be updated by stakeholders. The ESWG will coordinate the submitting and vetting of all data used in the economic analysis. This data includes generating unit information, load, wind profiles, emission prices, fuel prices, etc.

1. Confidentiality of Data

In addition to the treatment with respect to reporting requirements in Section 2.6, in all other activities SPP staff will take all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the OATT (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)).

2. Modeling Footprint

The modeling footprint will include 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.

3. Generating Unit Modeling Data

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. Specific data types will be derived from publically available inputs provided by the vendors. 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. These specific inputs use publically available data to ensure that the model will not contain sensitive data.

Stakeholders will be asked to review and provide updated values (if necessary) for certain data items. These data types include but are not limited to: Maximum MW Output, Minimum MW Output, 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. For the resource planning phase of this study, stakeholders will be asked to review and update a smaller set of input data.

4. Wind Resources

Futures may require the modeling of additional wind capacity above what is currently in service at the time of the assessment. The amount of wind which will be modeled is defined in the ITP Futures document which is proposed by the ESWG and approved by the appropriate governing committee. The target wind level is then met by including additional wind sites in the modeling footprint. The size and locations of these additional wind farms are approved by the ESWG.

5. Load Forecast Assumptions

A base load forecast used for the 20-Year Assessment will be approved by the Model Development Working Group (MDWG) and reviewed by the TWG and ESWG. Sensitivities may be developed for the futures.

6. Fuel and Emission Prices

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

7. Import/Export Limits

The ITP will focus on benefits to the SPP region. The interchange between SPP and other regions be kept to a minimum percentage of SPP's total load and capacity. The imports and exports will be set and benchmarked using hurdle rates and expected external system conditions for twenty years in the future. The ESWG will review 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 at seams will be reflective of expected facilities and arrangements that are consistent with the SPP futures being modeled. All of the ties within the SPP footprint will be modeled based on historical data. This historical data will be the most recent year available.

D. Modeling Methods

1. Model Development

As described in the sections below, the models used in the 20-Year Assessment are developed based on information accumulated from various sources. The model building process starts with a package utilizing publicly available data. The economic model is then reviewed members. In addition, the powerflow model 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 (constraint selection). SPP does not use Transmission Operating Guides in its 20-Year Assessment analyses.

2. Security-Constrained Economic Dispatch

The economic dispatch model will include stakeholder-vetted data. Unit cost related data such as costs and heat rates will be taken from publically available sources. Other data about the physical characteristics of generators that are not related to costs and heat rates will be reviewed and updated as needed by the members to provide company-specific values. These data will be used to produce the security-constrained economic dispatch (SCED) solution. The SCED solution requires dual optimization processes.

The first process is the security constrained unit commitment (SCUC). Here, the least cost combination of units is determined subject to unit-specific operational constraints (e.g., ramping, minimum output, min/max runtime, 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 by the SCUC process. Here, the units are dispatched 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- contingencies) to produce an overall least cost solution for regional load.

Data about the physical characteristics of generators, which are not related to costs and heat rates, will be reviewed and updated as needed by the members to provide company-specific values.

3. Power System Model for the economic dispatch model

The powerflow used in the 20-Year Assessment will be the latest MDWG model as approved by the TWG. Approved STEP projects as well as other special projects which are known by SPP staff (i.e. Entergy, AECI projects or those at other seams) will be added to the latest MDWG model as of the beginning of the study. This powerflow will be uploaded into the economic dispatch model.

Dynamics models will be developed based on existing model sets and will incorporate additional generation and transmission projects added through the ITP process.

4. Resource Planning Data

The resource planning data will be vetted by stakeholders to ensure that the modeling of stakeholder's generation capacity is accurate. The stakeholders will have the opportunity to update their data to ensure an accurate model.

5. Constraint Selection

The current NERC Book of Flowgates will be used as an initial list of constraints. Throughout the analysis SPP will define additional constraints which will be vetted and approved by the TWG.

Using a transmission analysis tool, SPP staff will identify additional constraints 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 is an iterative process which will look for the next constraint. For the purposes of this analysis N-1 and a few select PTDF interface constraints will be selected in order to control the flow in key transmission corridors. Not every flow will always be mitigated for every hour. Overloads can occur. The constraints are selected by performing an N-1 contingency analysis on all hours of the study year. All 300 kV and higher voltage facilities will be outaged; all 100 kV and higher voltage facilities in SPP will be monitored.

E. <u>Twenty-Year ITP Assessment Process</u>

1. Resource Planning

Language to be added by Black & Veatch.

2. Screening Analysis

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 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.

3. Security Constrained Unit Commitment and Economic Dispatch Analysis

SPP staff will use a security constrained economic dispatch software for the economic and unit commitment analysis. The model will solve using nodal LMPs which will dispatch the generation economically based unit characteristics, load information, and transmission constraints.

4. Limited Reliability Assessment

SPP staff will perform a limited reliability assessment to identify 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 this assessment is to test the robustness of the transmission system and is not intended to be a test for NERC Reliability Standards requirements[5].

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. This analysis will consist of an AC (thermal and voltage) contingency analysis, with and without the identified transmission plans. SPP will monitor 100 kV and above facilities while considering 100 kV and above contingencies. 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 be performed to identify potential areas of instability. These results may influence the selection of projects for the ITP. [6].

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

5. Solution Development

During the process of the 20-Year Assessment, SPP staff will review issues that are identified during the various phases of the study. Those issues may include: thermal overloads, voltage violations, constraint congestion, LMP variation and trapped generation. Staff will present these issues to stakeholders and ask for feedback on EHV solutions to those issues. Those proposed

Comment [jbh1]: From Doug K: In various places, "345kV+" shows up, sometimes without the notation EHV. Especially when just "345kV+" is noted, it is not clear as to whether the manual means "345kV and above", or if it means "above 345kV". It is further confused by SPP's use (in different documents) of EHV to mean it one way and in others the other way. And the power industry appears to use the EHV term for Above 345kV. I think in the manual here we mean to include 345kV. So I would recommend dropping the use of EHV and clearly stating what we mean in these places as ""345kV and above".

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

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

solutions will then be evaluated through a screening process to determine which solution sets work best. 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.

F. Valuation

The ESWG through its work with the Metrics Task Force (MTF) created the Metrics for 20-Year ITP Document. The document includes a description on the metrics proposed to measure both cost-effectiveness and robustness. The metric descriptions below have been taken from the Metrics document which was approved by the ESWG and MOPC.

1. Cost-Effective: Individual Futures

I. Minimization of the total costs (transmission capacity, generation capacity and APC) that meet the requirements of a specified future and;

- Includes emissions costs
- May include different fuel prices for different futures.
- Includes all the costs for EHV transmission
    - The gathering systems would be developed during the ITP 10 year plan (gathering systems have voltages less than 345kV).
- Includes an evaluation of whether or not a renewable energy standard or carbon cap standard is met
    - If not met, then add either transmission or generation capacity, whichever is lower cost. For example:
        - For transmission capacity, increasing voltage
        - For generation capacity, increasing wind capacity
- Includes an evaluation of adjusted production costs for alternative generation/transmission combinations that meet the future's target.
- Includes an evaluation on the cost of generation capacity depending on location (i.e. high wind zones vs low wind zones).

II. Would include comparative costs from various sources

- Real losses of energy
- Reserve margins
- Do not include changes in exports or imports in specified futures,[7] i.e. fix the import/export levels in the model to a historical level OR benchmark hurdle rates to peg SPP imports/exports at a historical level[8]. The study report shall clearly point out this limitation in assumption and describe how the results may be affected by it, e.g., what if the wind development to the north of SPP is considerably different (higher) than modeled, resulting in higher transfers through north SPP.

[7] There is some value in the imports/exports. However, under SPC direction the impact of changes on the transmission system from imports/exports in the SPP region is being limited.

[8] SPP staff should provide an example of the two options.

III. Additional factors to consider in individual futures:

- There are attributes of the transmission plans that may be evaluated in addition to lowest cost – to be provided later.
- Interconnection of new generation to target location (collection stations will be addressed in the 10 year plan)
  - Some locations may be ideal for wind, gas, coal, nuclear, etc.
- Interconnect new generation (GI process facilitation)
  - The EHV will target locations based on GI clusters and load which would add additional value.
  - Targeting location of EHV based on access for desirable application
  - Alternative View - Might fall into the "collector system" context which would be evaluated more in the 10 year ITP when looking at lower voltage, therefore it should be a 10 year ITP metric.

Comment [jbh2]: Rework into paragraph form

2. Flexibility: Meeting Multiple Futures

I. Multiple Futures

- Projects that show up multiple times as cost effective for each future make for cost effective planning.
  - Interconnections at target locations which show up in multiple futures will have greater weight.
- There is a weighting aspect that needs to be developed for ESWG and SPC consideration. This may include identifying different plans per future. The futures will be weighted by stakeholder determination.
- Cost effective solutions for individual futures may need to be modified in order to find a cost effective solution for multiple futures
- Additional factors to consider in multiple futures
  - Improved interconnection of new generation
  - Dispersion vs concentration of generation resources and the cost impact under different futures (i.e. wind)
  - Alignment of projects with plans external to the SPP region in accordance with FERC Order 890

II. Approach 1: Scenario Analysis

- Requires assignment of weights to various futures as noted above
- Requires running all futures against various transmission/generation plans
  - The transmission plans being evaluated for multiple futures will meet the requirements of each of the futures;
    Or
  - If not, must include an estimated cost for not meeting those requirements.
  - These estimated costs must be documented along with rationale for subsequent changes.
- Evaluates various transmission plans in terms of the transmission plan that has the highest weighting for the lowest costs.

III. Approach 2: Contingency Analysis

- **This is not an N-1 AC analysis. This is an adaptive process to calculate a value of the ITP in financial terms.**

- Overall plan is based on the future having the highest weight; i.e., the agreed upon ***expected*** future.
    - Requires a determination of which upgrades are built first (before the uncertainties are resolved); i.e., would include portions of the transmission system that are required for multiple futures
    - Requires a process by which designs can be changed in the event that the ***expected*** future does not come to fruition – contingency plans to go with the plan designed to meet the expected future.
- Can include the use of weights in the evaluation of having to change the plan when futures that are not expected occur.
    - Can evaluate transition costs in terms of a comparison to the costs incurred had the system been built to meet the alternative future.
    - Various alternatives can be evaluated using this same measure and compared on an expected value basis; i.e.,

$$\textbf{(Wgt*Cost of plan)} + \Sigma_j \textbf{(Wgts*Transition costs of alternative futures)}_j$$

3. Robustness Metrics (will be updated as ESWG reviews the CRA results)

I. Captures added value not previously quantified/qualified in SPP's traditional planning methods.

a) Improvements in reliability (value of improving the ability to keep the lights on)
- Value of delaying or advancing previously approved reliability projects
- Other values such as a backstop to a catastrophic event.
- Value of improved available transfer capability

b) Provides additional information to be considered in the siting of new generation capacity
- Locating transmission in proximity to:
    - Better wind locations
    - Concentration of natural gas lines
    - Water availability
    - Rail access
    - Lignite or coal resources
    - Solar sites
    - Highways
    - Load centers, substations sites
    - Environmentally sensitive areas
    - Existing corridors

c) Losses not captured by APC such as generation losses due to curtailment.
- The value of an increase or decrease in transmission line losses are captured in APC.
- The amount of additional or reduced energy due to a change in losses will be reported separately from amount embedded in the APC.

d) Increased effective capacity factors
- Capacity factor improvement of resources between the base and change cases, the capacity factor may change due to a reduction in congestion.
- Measures the benefit of adding transmission to reduce congestion on curtailed resources.

e) Ability to reduce cost of capacity held in reserve for regulation[9]

[9] Currently unable to define.

- The nodal security constrained economic dispatch software may not be the correct tool for this metric.
- Will focus more on hourly or five minute support and not planning or operating reserves. More focus placed on spinning reserve and ACE.

f) Positive impact on capacity losses

- Reduced capacity that can be reflected in reduced losses and the possible reduction in capacity margins.
- This metric will be used to capture a value for the capacity which may no longer be required due to a reduction in losses and capacity margin.

II. Levelization of LMPs

- This could be indicative of the value of transmission in providing access to economical sources of generation measured by the standard deviation in LMP price across the SPP footprint.
- Formula could be based on what the SPP Markets group uses in the Monthly State of the Market Report

III. Improved access to economical resources participating in SPP Markets

- Qualitative and quantitative based on quantitative metrics such as APC, volatility, increased sales, etc.
- Assesses the value of the, now 187 and possibly more, commercial paths where capacity increases and the average rate of the increase with additional transmission.
- Can be measured retroactively by calculating the number of new participants in the Market by Market Monitoring efforts.

IV. Change in operating reserves

- Calculation of reserves before and after transmission projects (MW x $/MW implementation cost)
- Loss of Load Probability (LLP) studies will show the reduced requirements.
- Use Gas CT as base construction
- Evaluation of the regulation and following reserves needed for wind resources
- Reduction in need for reserve zones

V. TLR Reduction – Enabling Market Solutions

- This should be a subset analysis that would not be a full 8760 hr analysis. This analysis could be limited to a subset of days or hours.
- Capture the value of fewer transmission loading reliefs during specific durations of the year.
- The valuation will be based on a review of historical and projected data.

VI. Limited export/import improvements

- Will capture the effects on both the generation and the load.
- Need to consider the requirements under FERC Order 890 but not specifically use the import/exports capabilities for valuing the transmission projects in the ITP. Multi-region studies should capture the issues related to what is needed for import/export capability under Order 890. Surplus wind exports would be handled under multi-regional studies.

VII. Improved economic market dynamics not measured in the security constrained economic dispatch model.

- Can be used to look at constrained areas
    - o Does an increase in robustness eliminate, to a degree, the need for Narrowly Constrained Areas as defined by MISO?
- This metric will be used to capture the value of eliminating load or congestion pockets due to the reduction of redispatch.

VIII. Improved economic market dynamics measured in the nodal security constrained economic dispatch model

- Value added by the change in average marginal cost. Determine if the cost of the next marginal MW increased or decreased due to the addition of the transmission project.
- Marginal cost is defined as the cost of the marginal unit
- Has the cost of the next marginal MW increased or decreased by adding the additional transmission project?
- Averaged over either an on or off peak period or a full 8760 analysis as determined by SPP staff

IX. Reduction in market price volatility

- This relates to volatility over time and not geographic volatility
- Hedging tools will be reduced in value with less price
- Without stochastic analysis this metric is difficult to capture.
- The stochastic analysis would require a significant amount of computer time.

X. Reduction of emission rates and values

- CO_2, NO_X, SO_2, values will be input into the model, thereby capturing the impact to the dispatch and the APC.
- Currently the application for mercury is not well defined; however the units of mercury emissions will be captured. Reducing pounds/tons of mercury has different values to different market participants.

XI. Transmission corridor utilization

- How to efficiently utilize the ROW
- Must also consider the environmental impacts of the transmission.

XII. Ability to reduce cycling of base load units

- Excessive cycling increases maintenance costs of units requiring capital investment.
- New transmission that would impact this cycling would provide a value to the generation.
- Cycling is defined as a unit ramping up and down within its minimum and maximum.
- The number of cycles is determined by counting the number of times a unit's output crosses the average operating level.
- The BA or TO will determine what is considered "normal" and "excess" cycling.
- This metric will apply to coal and nuclear plants which are 350MW and larger.

XIII. Generation Resource Diversity

- Fuel diversity adds fuel adjustment rate stability.

XIV. Ability to serve unexpected new load

- Results could be captured when you have unexpected extreme load growth.
- Transfer X% of additional energy to a load pocket with low impact on LMPs.
- Test the robustness by shifting load from one major load center to another.

XV. Part of Overall EHV Overlay Plan

- There is some value if the interim projects solve an immediate problem and can be incorporated into the long term comprehensive EHV Plan.

G. Deliverable

1. Finalize Solution

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 futures. The results of this analysis will be a single transmission plan (composed of multiple 345 kV+ projects) that is robust, being adaptable for all of the futures considered, and adding greater incremental value than incremental cost.

2. Report

The deliverable for the 20-Year analysis will be a single transmission including staging and timing considerations to convey the appropriate order of implementation. The results of the analysis will be included in the 20-Year ITP Report.

IV. Ten-Year Integrated Transmission Planning

The process for the 10-Year Assessment has not yet been developed. Once the process development has been completed this section of the manual will be updated to include that process.

A. Purpose

Add Text

B. Futures Evaluation

Add Text

C. Data Requirements

Add Text

1. Confidentiality of Data

In addition to the treatment with respect to reporting requirements in Section 2.6, in all other activities 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)).

2. Generating Unit Modeling Data

Add Text

3. Reliability/Must-Run Conditions

Add Text

4. Wind Farms

Add Text

5. Interaction with ERCOT & WECC

Add Text regarding DC Ties

6. Stakeholder Review of Modeling Assumptions

Add Text regarding DC Ties

D. Assumptions

1. Load Forecast Assumptions

Add Text

2. Fuel Prices

Add Text

3. Emission Prices

Add Text

4. Modeling Footprint

Add Text

5. Import/Export Limits

Add Text

E. Modeling Methods

Add Text

1. Power Flow/Security-Constrained Economic Dispatch

Add Text

2. Flowgate Definition

Add Text

F. Ten-Year ITP Process

Add Text

1. Model Development

Add Text

2. Flowgate Selection

Add Text

3. Screening Analysis

Add Text

4. Additional Flowgate Analysis

Add Text

5. Security Constrainted Unit Commitment and Economic Dispatch Analysis

Add Text

6. PSS®E MUST Commercial Path Analysis

Add Text

7. Eastward Transfer Capability Analysis

Add Text

8. Solution Development

Add Text

G. Calculation of Benefits

Add Text

1. Cost-Effective Planning

Add Text

H. Deliverable

Add Text

1. Finalize Solution

Add Text

V. Near-Term Integrated Transmission Planning

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 20-Year and 10-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.

A. Purpose

The ITP 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.

B. 20-Year and 10-Year ITP Interaction

The ITP 20-Year and 10-Year plans will be incorporated into the Near-Term Assessment annually. The plans will serve as part of a pool of solutions from which the 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.

C. Data Requirements

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.

Deleted: Any entity that is subject to the NERC Reliability Standards is required to provide data to the Transmission Provider in accordance the NERC Reliability Standards for Modeling, Data and Analysis (the "NERC MOD Standards"). ¶

Deleted: W

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.[10]

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

1. Confidentiality of Data

In addition to the treatment with respect to reporting requirements in Section 2.6, in all other activities 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)).

D. <u>Assumptions</u>

The Near-Term Assessment will be performed on an annual basis. The study will be performed on a shorter planning horizon than the 10-Year assessment and will focus on the reliability of the system. The 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;
    - 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;
  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 Near-Term Assessment.

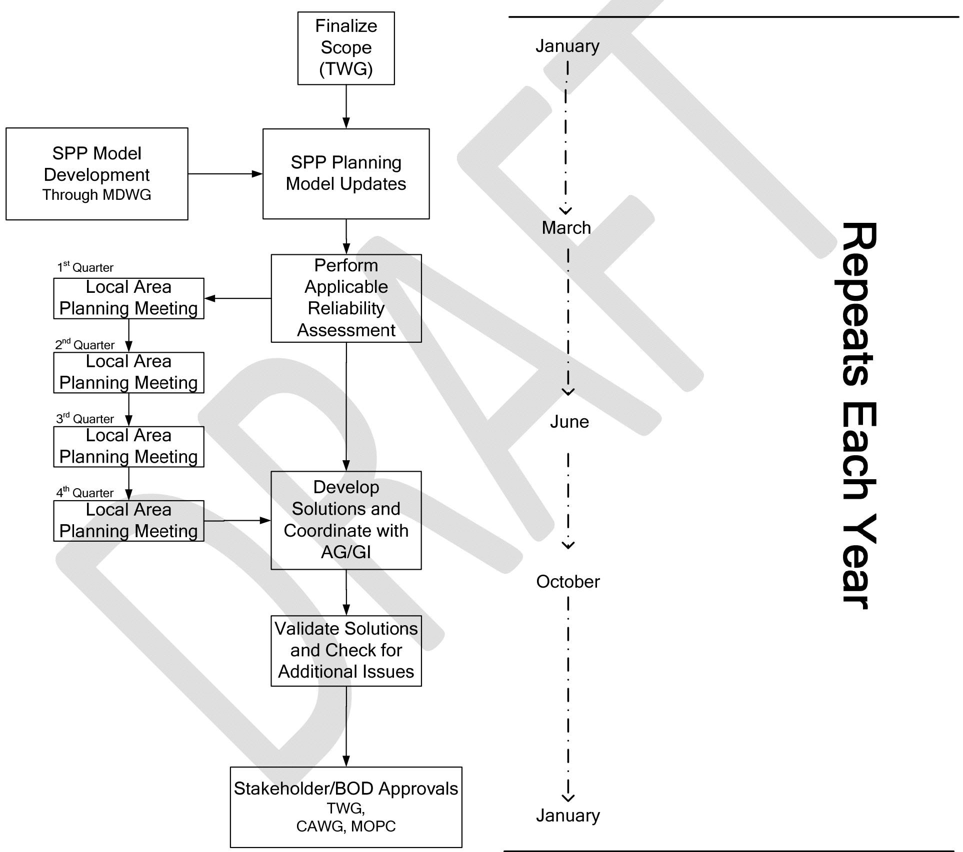
1. MDWG Modeling

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

E. Near-Term ITP Process

Planning within SPP is a collaborative process with Transmission Owners, users, and other stakeholders. This 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 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.

1. Model Development Process

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 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 ITP 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.

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 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[11];

[11] Eliminates generators that may drop out as a result of changes in study results

- o The generating resource has acquired air and environmental permits where applicable;
- o The generating resource has started construction with major equipment procurement contracts awarded; and
- o The generating resource's unit(s) must be dispatchable and committable.
- o If a generating resource does not meet all the above requirements, a formal request for generation capacity to be included in the ITP Near-Term can be made to TWG on a case by case basis.

In later years of the Near-Term Assessment analysis when there is a shortfall between interchange, generation, and load, the following process will be used to address generation deficiencies[12]:

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.

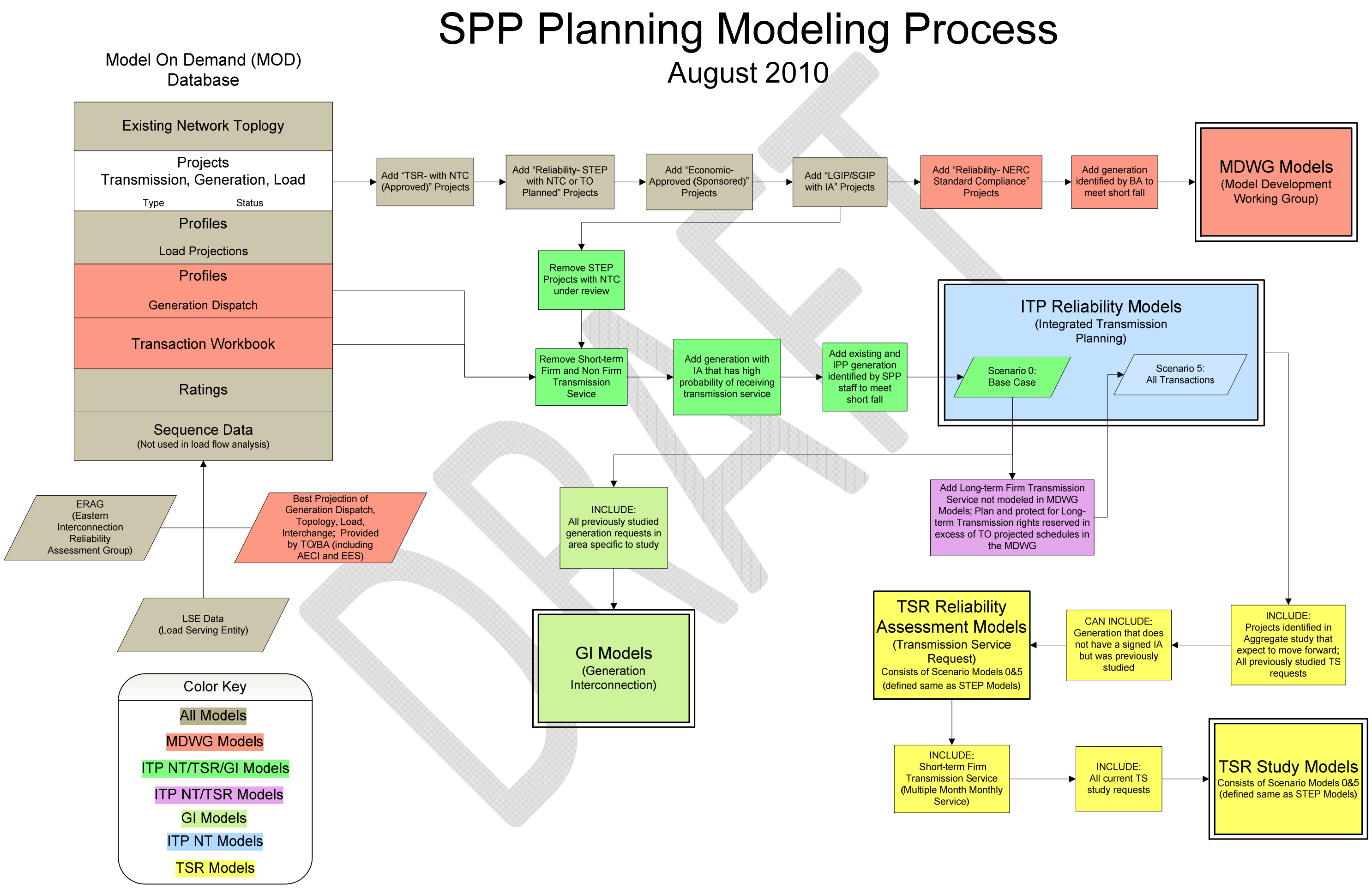
SPP uses scenarios to evaluate reliability. The number of scenarios is determined each year and approved by the TWG.

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

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

Deleted: <#>Exhaust the customer's dispatchable designated network resources until the network resources are sufficient to meet network load.¶
¶
<#>Dispatch generation by using dispatch orders provided by the transmission planning personnel of the SPP Transmission Owners and by representatives of the transmission service customers.¶
<#>Add generation from behind the meter generating units. This generation consists of dispatchable behind the meter generation that may not already included in the SPP MDWG models.¶
¶
<#>If the customer's dispatchable designated load cannot be served after Step One, then exhaust the customer's other dispatchable, operational generation that is not designated.¶
¶
<#>Dispatch generation by using dispatch orders provided by the transmission planning personnel of the SPP Transmission Owners and by representatives of the transmission service customers.¶
<#>Add generation from behind the meter generating units. This generation consists of behind the meter generation that may not already included in the SPP MDWG models.¶
¶
<#>If the customer's designated load cannot be served after Step One and Step Two, exhaust the Host Transmission Owner's existing dispatchable generation. ¶
¶
<#>Dispatch generation by using dispatch orders provided by the transmission planning personnel of the SPP Transmission Owners and by representatives of the transmission service customers.¶
¶
<#>If the customer's network load cannot be served after the above steps, exhaust Independent Power Producer's ("IPP") existing dispatchable generation in the Host Transmission Owner's modeling area.¶
¶
<#>Exhaust IPP generation on a pro rata, as available basis accounting for firm transmission commitments. In other words, Use power from each IPP to meet the customer's designated load. The amount of power from each IPP will be determined using the total amounts available based on the IPP's historical generating levels minus the amount of power to model existing transmission service from the IPP.¶
¶
<#>Finally, if a customer's network load cannot be served after applying the above steps, exhaust existing primary modeling area dispatchable generation with includes IPP's existing generation and existing primary modeling area generation.¶
¶
<#>Similar to Step Four, exhaust this generation on a pro rata, as available bas ... [1]

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 18 pt + Indent at: 36 pt


SPP Planning Modeling Process
August 2010
Model On Demand (MOD) Database
Existing Network Toplogy
Projects
Transmission, Generation, Load
Type
Status
Profiles
Load Projections
Profiles
Generation Dispatch
Transaction Workbook
Ratings
Sequence Data
(Not used in load flow analysis)
ERAG (Eastern Interconnection Reliability Assessment Group)
Best Projection of Generation Dispatch, Topology, Load, Interchange; Provided by TO/BA (including AECI and EES)
LSE Data (Load Serving Entity)
Add "TSR- with NTC (Approved)" Projects
Add "Reliability- STEP with NTC or TO Planned" Projects
Add "Economic- Approved (Sponsored)" Projects
Add "LGIP/SGIP with IA" Projects
Add "Reliability- NERC Standard Compliance" Projects
Add generation identified by BA to meet short fall
MDWG Models
(Model Development Working Group)
Remove STEP Projects with NTC under review
Remove Short-term Firm and Non Firm Transmission Sevice
Add generation with IA that has high probability of receiving transmission service
Add existing and IPP generation identified by SPP staff to meet short fall
ITP Reliability Models
(Integrated Transmission Planning)
Scenario 0: Base Case
Scenario 5: All Transactions
INCLUDE: All previously studied generation requests in area specific to study
Add Long-term Firm Transmission Service not modeled in MDWG Models; Plan and protect for Long-term Transmission rights reserved in excess of TO projected schedules in the MDWG
GI Models
(Generation Interconnection)
TSR Reliability Assessment Models
(Transmission Service Request)
Consists of Scenario Models 0&5 (defined same as STEP Models)
CAN INCLUDE: Generation that does not have a signed IA but was previously studied
INCLUDE: Projects identified in Aggregate study that expect to move forward; All previously studied TS requests
INCLUDE: Short-term Firm Transmission Service (Multiple Month Monthly Service)
INCLUDE: All current TS study requests
TSR Study Models
Consists of Scenario Models 0&5 (defined same as STEP Models)
Color Key
All Models
MDWG Models
ITP NT/TSR/GI Models
ITP NT/TSR Models
GI Models
ITP NT Models
TSR Models

2. Inter-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. Transmission Operating Guides

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

4. 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[13]

5. 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.

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.

F. Deliverable

The deliverable for the 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 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 Near-Term Assessment results will also contain a list of at least the following upgrades:

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

- o Regional upgrades required to maintain reliability in accordance with the NERC Reliability Standards and SPP Criteria in the near term horizon;
- o Zonal upgrades required to maintain reliability in accordance with more stringent individual Transmission Owner planning criteria in the near term horizon; and
- o 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.

1. Finalize Solution

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

VI. 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, 10-Year, and Near-Term Assessments which are within the financial window as approved by the BOD. The NTC is sent to the incumbent 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.

VII. 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.

A. 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.

Deleted: MOPC and the

Comment [rah3]: Removed since it's duplicate information

Deleted: ¶
<#>Ongoing Economic Modeling & Methods Process¶
¶
<#>Interaction with Other SPP Data & Modeling Activities¶
¶
The transmission network models applied to transmission project/upgrade economic analyses are derived from underlying seasonal power flow cases as constructed and managed by the SPP Model Development Working Group ("MDWG"). SPP has developed specific procedures for converting underlying MDWG power flow cases for interface with the simulation models applied for network economic analyses.¶
¶
For efficiency of activities within SPP, the same or similar transmission network models and simulation models are also applied to other market simulation and analysis activities within the SPP organization.¶

Formatted: Font: 11 pt

Appendix A

Type	Status	Description	MDWG	STEP/ Tariff	Special Study
TSR	w/NTC (Approved)	Projects identified through Aggregate Study with an executed Transmission Service Agreement and an issued Notice To Construct	X	X	X
	Proposed (No NTC)	Proposed projects that do not have an NTC			X
LGIP	w/GIP	Projects identified through the Large or Small Generator Interconnection Procedures (LGIP, SGIP) with an executed Large Generator Interconnection Agreement and not on suspension	X	X	X
	w/GIP on Suspension	Projects identified through the Large or Small Generator Interconnection Procedures (LGIP, SGIP) with an executed Large Generator Interconnection Agreement and on suspension			X
	No GIP	Projects without an executed Large or Small Generator Interconnection Agreement (LGIP, SGIP)			X
Reliability	STEP (w/NTC) or TO Planned	Appendix B Projects that have a Notice to Construct or Transmission Owner Planning Criteria with an issued Notice To Construct	X	X	X
	STEP Proposed (No NTC)	Appendix A Projects and projects that are being studied as part of the current STEP process, or are under consideration			X
	NERC Standard Compliance	Projects needed to comply with NERC Reliability Standards or SPP Criteria that are not part of STEP	X		X
Economic	Approved (Sponsored)	Projects identified through Attachment O identified that have been shown to provide regional economic benefit that have a contract that financially commits a Project Sponsor	X	X	X
	Approved (Not Sponsored)	Projects identified through Attachment O identified that have been shown to provide regional economic benefit that have no contract to build			X
Requested	Stakeholder Driven	Transmission upgrades, requested by a Transmission Customer or other entity, which do not meet the definition of any other category of Network Upgrades.	X		X
	Alternative	Projects that are alternatives to any TSR, STEP, or Economic Project. i.e. differed projects			
Network	Energized	Projects that are in-service from a previous MOD Type & Status. Constructed facilities that are in-service.	X	X	X
Network	Outage	Projects that change network topology status. Constructed facilities that are out-of-service or normally open.	X	X	X
Network	Update	Projects that updates network data	X	X	X

Appendix B

SPP Transmission Operating Guides Review Procedure

This procedure documents the process of how a Transmission Operating Guide (TOG) shall be included in the ITP and SPP Aggregate Transmission Service Studies (ATSS). In most cases TOGs are not intended to indefinitely defer needed Transmission System upgrades. Effective TOGs shall be utilized in all transmission tariff service functions and OATT planning processes.

For a TOG to be considered for use in the ITP and ATSS as a possible mitigation plan, it shall be on file with SPP. An effective TOG must state the system conditions under which the TOG is to be used and describe, in detail, the action the operators will take. The TOG must be signed by someone in charge of operations from the Transmission Owner or transmission operator submitting the TOG.

An effective TOG shall continue to be used in evaluation of the ITP and ATSS unless the facility-owning Transmission Owner or transmission operator withdraws the TOG. In cases where the TOG is withdrawn before the TOG becomes ineffective, any Transmission System Upgrades lie with the Transmission Owner.

A new TOG provided as interim mitigation for an SPP-required project shall automatically be withdrawn when the project is completed.

A TOG is considered an effective solution for facilities that are not listed in the TOG if, in the act of implementing the TOG for the elements listed, other overloads or voltage violations are corrected.

Service Upgrades associated with new Transmission Service Requests or Designated Resources that cause a TOG to be ineffective will be classified as Base Plan Upgrades in accordance with Attachment J.

Transmission System upgrades that become necessary because a TOG has been identified to be ineffective in order to maintain the reliability of the Transmission System shall be categorized as Reliability Upgrades, utilizing the procedures of Attachment O of the OATT.

The upgrade(s) proposed to address an ineffective TOG may work towards either eliminating the TOG or the ineffectiveness of the TOG.

Effective TOGs
1. A TOG addressing Transmission System loading must include a short-term emergency rating which allows sufficient time to implement the TOG.
2. A TOG requiring generation redispatch must indicate if generator location is critical and, if so, must state in detail which units or plants will be re-dispatched. Absence of such specificity means location is not critical and generators may be selected from the fleet the entity has authority to run. The ramp rate of the generation must be capable of relieving the overload or voltage issue within the time allowed as specified in the TOG.
3. A TOG must not cause a violation elsewhere on the Transmission System.
4. A TOG addressing a voltage violation must provide for restoring minimum acceptable voltage conditions within a time frame so as not to cause permanent equipment damage.

A TOG shall identify the means by which system control is implemented. That is, if supervisory control is utilized it must so state.

Page 26: [1] Deleted	Rachel Hulett	9/13/2010 5:48:00 PM

Exhaust the customer's dispatchable designated network resources until the network resources are sufficient to meet network load.

Dispatch generation by using dispatch orders provided by the transmission planning personnel of the SPP Transmission Owners and by representatives of the transmission service customers.
Add generation from behind the meter generating units. This generation consists of dispatchable behind the meter generation that may not already included in the SPP MDWG models.

If the customer's dispatchable designated load cannot be served after Step One, then exhaust the customer's other dispatchable, operational generation that is not designated.

Dispatch generation by using dispatch orders provided by the transmission planning personnel of the SPP Transmission Owners and by representatives of the transmission service customers.
Add generation from behind the meter generating units. This generation consists of behind the meter generation that may not already included in the SPP MDWG models.

If the customer's designated load cannot be served after Step One and Step Two, exhaust the Host Transmission Owner's existing dispatchable generation.

Dispatch generation by using dispatch orders provided by the transmission planning personnel of the SPP Transmission Owners and by representatives of the transmission service customers.

If the customer's network load cannot be served after the above steps, exhaust Independent Power Producer's ("IPP") existing dispatchable generation in the Host Transmission Owner's modeling area.

Exhaust IPP generation on a pro rata, as available basis accounting for firm transmission commitments. In other words, Use power from each IPP to meet the customer's designated load. The amount of power from each IPP will be determined using the total amounts available based on the IPP's historical generating levels minus the amount of power to model existing transmission service from the IPP.

Finally, if a customer's network load cannot be served after applying the above steps, exhaust existing primary modeling area dispatchable generation with includes IPP's existing generation and existing primary modeling area generation.

Similar to Step Four, exhaust this generation on a pro rata, as available basis for firm transmission commitments. The amount of power from each IPP and from each primary modeling area generation will be determined using the total amounts available based on the maximum generating levels minus the amount of power to model existing transmission service from the IPP and primary modeling