Southwest Power Pool

Southwest Power Pool

TRANSMISSION WORKING GROUP

June 9, 2011

Webconference

• M I N U T E S •

Agenda Item 1 – Administrative Items

The meeting was called to order at 10:00 a.m. The following members were in attendance or represented by proxy: (Attachment 1 – Proxies)

TWG Members

John Chamberlin, City Utilities of Springfield
Ronnie Frizzell, Arkansas Electric Cooperative
John Fulton, Southwestern Public Service Company
Joe Fultz, Grand River Dam Authority
John Mayhan for Dan Lenihan, Omaha Public Power District
Randy Lindstrom, Nebraska Public Power District
Mark Loveless for Jim McAvoy, Oklahoma Municipal Public Authority
Nathan McNeil, Midwest Energy
Matt McGee, American Electric Power
John Payne, Kansas Electric Power Cooperative
Jason Shook, GDS Associates for ETEC
Mitch Williams, Western Farmers Electric Cooperative
Harold Wyble, Kansas City Power & Light

Other Stakeholders and Staff

Paul Arnold, Power Engineers
Roy Boyer, Southwestern Public Service Company
Derek Brown, Westar Enregy
Bruce Cude, Southwestern Public Service Company
Ricardo Galarza, PSM Consulting
Tony Gott, Associated Electric Cooperative
Dan Hartman
Rachel Hulett, SPP Staff
Deepthi Kasinaduni, Grand River Dam Authority
Lloyd Kolb, Golden Spread Electric Cooperative
Jim Krajecki, Customized Energy Solutions
Jake Langthorn, Oklahoma Gas and Electric
Tim Miller, SPP Staff
Nate Morris, Empire District Electric
Harshikesh Panchal, Constellation Energy
Ronda Redden, Oklahoma Gas and Electric
Josh Ross, SPP Staff

Agenda Item 2 – 2011 ITP10 Constraint Review

Josh Ross, SPP Staff, explained the ITP10 constraint review. Since the economic model can only use constraints to dispatch around, this identification of constraints is an important step in the economic assessment. SPP staff began the list with the NERC Book of flowgates and the latest TWG review of flowgates.

Several questions arose about new constraints being applied that might impact the results. Staff responded that any new proposed constraints would be evaluated by staff to determine if they warrant inclusion in the ITP10 constraint list. A question came up regarding the need for some of the constraints that would most likely go away by 2022 due to transmission upgrades that are currently being built. Staff responded that the OTDF constraints of this nature would not cause any congestion, as these constraints would not bind and would thus have zero impact on the economic dispatch. The PTDF constraints of this nature are being evaluated by SPP Staff to determine if they should be removed from the constraint list.

Staff noted that the constraints will be used in the economic analysis to determine congestion. Based on the congestion, staff and the members will have to determine if they should create a constraint to dispatch around the congestion or develop a transmission solution to resolve the congestion. This will be a crucial part of the assessment.

Staff has received member feedback, changing constraints or ratings. Staff asked TWG to provide any additional comments to staff by Friday, June 10.

Agenda Item 3 – ITP Draft Manual Review

Rachel Hulett, SPP Staff, asked the TWG for comments on the ITP10 portion of the draft ITP manual. A few comments were made in the meeting (Attachment 2 – ITP Manual). Rachel asked the group to provide comments prior to the next call. The TWG will be asked to endorse the manual at the next conference call.

Agenda Item 4 – Update on Criteria 5 Action Item

Rachel Hulett informed the TWG of progress on the Criteria 5 action item assigned to ORWG to revise the Criteria to reflect a high voltage maximum limit of 1.05 pu for operational studies ("Ask ORWG to provide clarification in Criteria 5.2.4.1d that "post-contingent bus voltages in excess of +/- 10%" should be the 30-minute allowance"). SPP Operations relayed this message: ORWG does not want to change the limits for the following reasons: the next day studies use the MDWG models as the starting point for analysis, and the MDWG models have high voltage problems present; this will require more interaction with the operators and they didn't want to supply mitigations for problems starting at 1.05 pu. SPP Operations is willing to change an area's next day study limits to 1.05. Please contact Jason Smith to change. TWG discussed this and took away an action item to talk to their operations folks to verify they're operating system at 1.05 pu and why they do not want to change the next day studies limits.

> **AI: Members talk to their respective operators to understand and determine if operational studies should use a maximum 1.05 pu voltage limit.**

Agenda Item 5 – Closing

The next meeting was scheduled for June 22, 2011 from 10-12 p.m. The meeting was adjourned at 11:15 a.m.

Respectfully Submitted,

Rachel Hulett
TWG Secretary

OPPD, John Mayhan for Dan Lenihan

From: LENIHAN, DANIEL J [mailto:djlenihan@oppd.com]
Sent: Wednesday, June 08, 2011 5:27 PM
To: Rachel Hulett
Cc: Williams, Noman; Mayhan, John
Subject: OPPD TWG Proxy for 6/9 meeting

Rachel,

John Mayhan will be my proxy for the TWG meeting tomorrow, 6/9/11.

Thanks.

Dan Lenihan, P.E.
Manager, Transmission & Distribution Planning
Omaha Public Power District
Energy Control Center, ECC-5
4325 Jones Plaza, Omaha, Nebraska 68105-1066
Voice: (402) 552-5126
Fax: (402) 552-5679
Email: djlenihan@oppd.com

OMPA, Mark Loveless for Jim McAvoy

Mark Loveless vocalized in the meeting that Jim McAvoy gave him his proxy for the meeting.

Recorded by staff secretary

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Draft

Integrated Transmission Planning Manual

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SPP Engineering

PUBLISHED: [Click **here** and type **MM/DD/YYYY**]
LATEST REVISION: 05/02/2011

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SPP Southwest Power Pool

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Table of Contents

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Southwest Power Pool

1 Introduction

1.1 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 300 kV or greater
6. ERCOT – Electric Reliability Council of Texas
7. 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
8. FERC – Federal Energy Regulatory Commission
9. 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. 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. MAPP – Mid-Continent Area Power Pool
12. 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. MISO – Midwest Independent Transmission System Operator
14. MOPC – Markets and Operations Policy Committee
15. 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. NERC – North American Electric Reliability Corporation
17. NERC TPL – NERC Transmission Planning Standards
18. 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. OATT – Open Access Transmission Tariff: SPP's transmission tariff as posted on SPP's website
20. PJM – PJM Interconnection

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21. 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. ROW – Right-of-Way: The ROW identifies the strip of land which is needed for transmission purposes
23. 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. SERC – SERC Reliability Corporation
25. SPP – Southwest Power Pool, Inc.: SPP is a Regional Transmission Organization
26. 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. 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. 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. 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. WECC – Western Electricity Coordinating Council

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1.2 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 also outline the processes for the three Integrated Transmission Planning components: 20-Year, 10-Year, and Near-Term Assessments.

1.3 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.

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.

[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.

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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.

1.4 Background

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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.

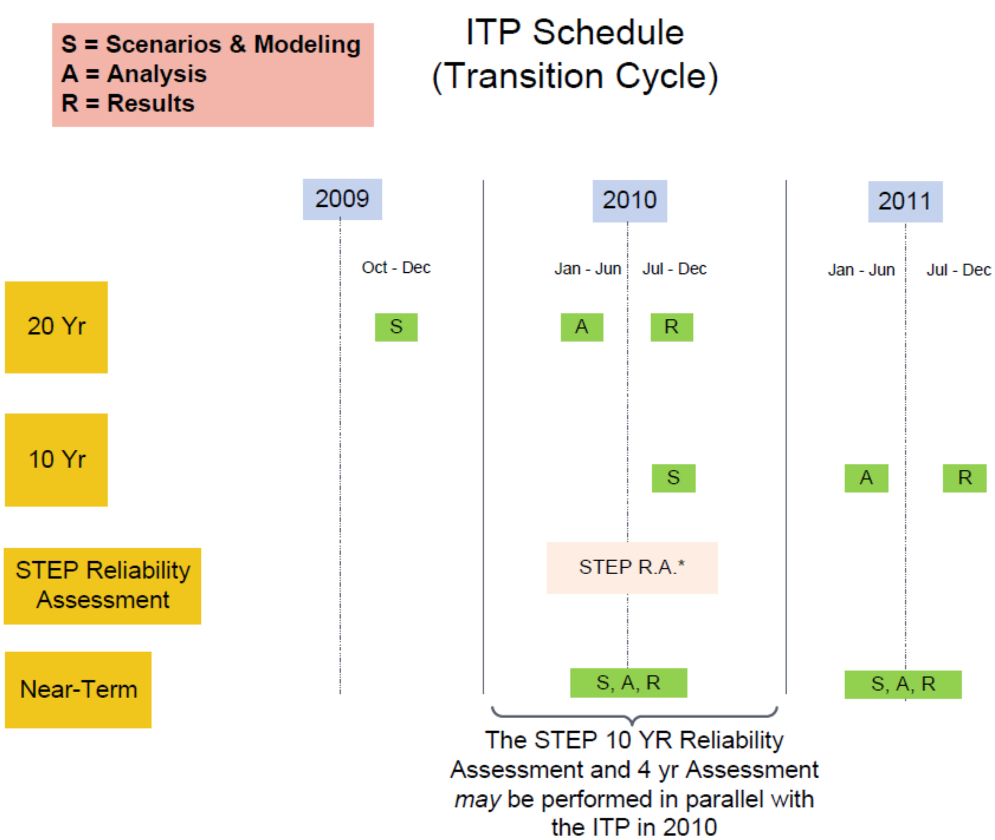
SPP began performing its planning duties in accordance with the ITP process in January of 2010, shortening the 20-year Assessment from an 18 month process to a 12 month process.

[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

2 Transmission Planning Upgrade Process

2.1 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.



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

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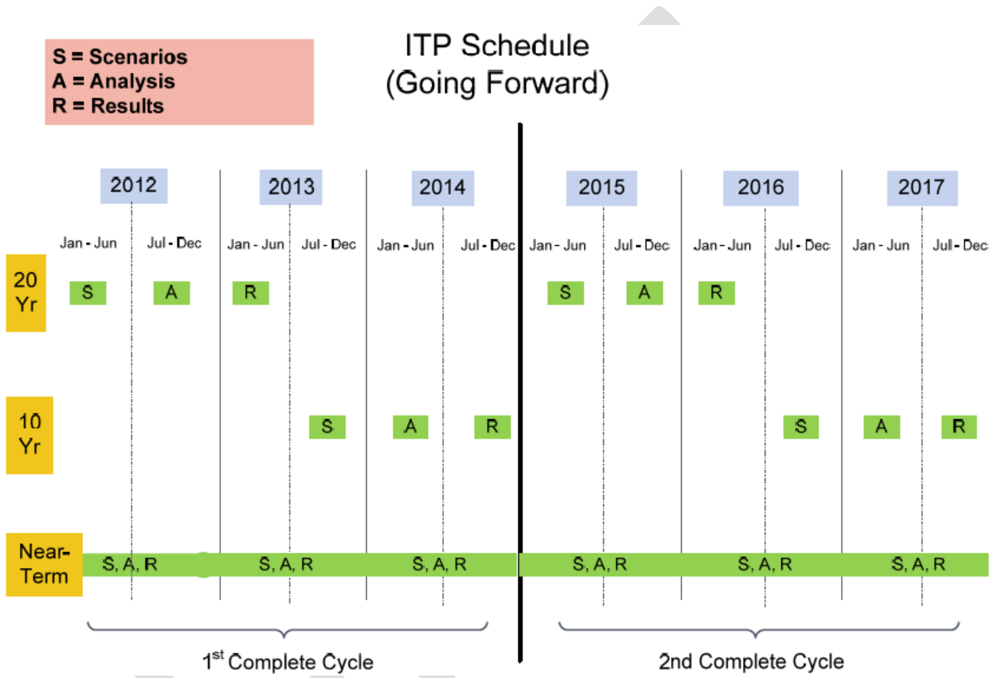
Moving forward, evaluation of future scenarios that may affect the ITP will occur during the first half of 2012 for the 20-Year Assessment and during the second half of 2013 for the 10-Year Assessment. The 20-Year Assessment will begin in year one and be completed in year two. The 10-Year Assessment 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.



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

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transmission network which adheres to the ITP principles and also keeps the FERC "Nine Transmission Principles" in the forefront.[4]

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

2.2.1 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.

[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.

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

2.3 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.

3 Twenty-Year Integrated Transmission Planning

3.1

3.2 Purpose

The first phase of the ITP process is the 20-Year Assessment 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.

3.3 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

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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.

3.4 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.

3.4.1 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)).

3.4.2 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.

3.4.3 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.

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3.4.4 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.

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3.4.5 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.

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3.4.6 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.

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3.4.7 Import/Export Limits

The ITP will focus on benefits to the SPP region. The interchange between SPP and other regions will 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.

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3.5 Modeling Methods

3.5.1 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 by SPP 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 (flowgate selection). SPP does not use Transmission Operating Guides in its 20-Year Assessment analyses.

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3.5.2 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 publicly 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.

3.5.3 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.

(Suggested TWG language: Typical dynamic models for projected generation will be used for the 20-Year Assessment in those scenarios in which steady state power transfers indicate minimal stability margins.)

3.5.4 Resource Planning Model

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.

3.5.5 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.

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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.

3.6 Twenty-Year ITP Assessment Process

3.6.1 Resource Planning

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. 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 resources will be spatially located within the SPP pricing areas with the aid of GIS databases showing locations of transmission lines, natural gas pipelines, railroads, waterways, substations, etc.

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

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3.6.2 Phase I

The data defining the generating characteristics of all existing 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 meet future peak demand and energy requirements. In addition generators 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 timeframe, maintaining the 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.

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.

3.6.3 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 siting effort will incorporate renewable requirements, 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 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.

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- Site proxy generation by zone: Site expansion 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 tendency to reduce impact on transmission system.
- Limit capacity to 2,400 MW maximum per location: Limiting total capacity per location potentially minimizes impact of contingencies removing large blocks of capacity from service.

3.6.4 Phase III

After the resource sitings are approved, the resource additions will be input to the SPP database 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 analysis by SPP and will allow SPP to connect the resource to specific buses for the transmission models.

3.6.5 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.

3.6.6 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.

3.6.7 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].

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

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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.

3.6.8 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, flowgate 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 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.

3.7 Valuation

Three distinct phases to the transmission plan development will occur. A transmission least cost analysis will create transmission plans that help the SPP system satisfy the requirements of each future, a cost-effective analysis will identify common elements found in the multiple future least cost plans and begin evaluating project alternatives in order to provide a single base for use in the application of the robustness metrics.

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

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Each phase of the valuation will rely upon certain metrics as outlined by the ESWG through its work with the Metrics Task Force (MTF). The Metrics for 20-Year ITP document includes a description of the metrics proposed to measure both cost-effectiveness and robustness.

3.7.1 Transmission Least Cost Evaluation

This initial engineering analysis phase will produce a transmission least cost plan for each future. The plans will be developed to ensure that the future is met in a manner that minimizes transmission construction and maintenance costs. The principles used to select projects in this phase of the valuation include preferences for shorter line lengths, simpler projects and project termination into existing substations. Requirements will be specific to the futures under study and in this phase of the study must be completely satisfied by the transmission plan developed for the future.

3.7.2 Cost-Effective Transmission Evaluation

The cost-effective transmission plan will combine the transmission least cost plans into a single plan for use as a base in the robustness valuations. The principles used to select projects in this phase include the minimization of the total costs (transmission capacity, generation capacity and APC). A common plan including the projects found in every transmission least cost plan will serve as the basis for these calculations. Additional projects will be added to the common plan in order to form the cost-effective plan when the benefit of the project outweighs the costs. Where multiple alternative projects are considered, the best performing project will be selected for inclusion in the plan.

3.7.3 Robustness Metrics

The robustness metrics are described in more detail in the ITP 20-Year Assessment Robustness Metrics Procedural Manual[7]. These 15 metrics are meant to be options which can be used to capture additional value provided by projects studied in the 20-Year Assessment. It is understood that all metrics may not be able to be calculated during the 20-Year Assessment in 2010.

1) **Ability to capture 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)

   This metric has three distinct components, or sub-metrics, each addressing a different aspect of improved reliability:

   1) Value of delaying or eliminating the need for previously approved reliability projects; monetizes the reliability benefit as the avoided cost (or additional cost) in dollars of delaying or canceling (or accelerating) previously approved reliability projects.

[7] http://www.spp.org/section.asp?pageID=128

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2) Value of improved Available Transfer Capabilites (ATCs) of the SPP grid; provides a qualitative (non-monetized) assessment of the added flexibility for the potential redirection of power flows within SPP made possible by increase ATCs. The challenge in defining this metric is to develop a meaningful weighting structure of ATCs defined for multiple combinations of points of receipt and points of delivery.

3) Other values, such as a backstop to a catastrophic event; provides a qualitative assessment of the improved reliability of the grid in its ability to withstand the impact of catastrophic events electrically expressed as multiple contingencies.

b) Enables efficient location of new generation
This metric is a quantitative measure of the ability of a transmission project or portfolio to provide for the efficient location of new generation capacity.

c) Reduced losses not captured in APC
Relative to a base case transmission expansion plan, each alternative transmission expansion plan will impact total losses in the system. This metric will serve as a first step in the calculation of the metric to calculation the impact on capacity losses and will give SPP stakeholders a qualitative measure for evaluating the relationship between a reduction in losses and the monetary and physical savings from reduced capacity and capital costs.

d) Increased effective capacity factors
The value of the capacity factor improvement of resources between the base and change cases should be captured. The capacity factor may change due to a reduction in congestion. This is a measure of the value of adding transmission to reduce congestion on curtailed resources.

e) Ability to reduce cost of capacity held in reserve for regulation. This metric has not yet been developed.

f) Positive impact on capacity losses
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. The reduced capacity can be reflected in reduced losses and the potential reduction in capacity margins.

2) Levelization of LMPs

The Levelization of LMPs metric will provide SPP stakeholders a qualitative indicator for the impact an alternate transmission topology makes on generation owners' ability, across the SPP footprint, to compete on equal grounds. In the absence of congestion and losses in the system, any generator has the potential to serve any load and there will be one single system price in each hour. A transmission system with no constraints and low losses makes the electricity market more contestable as it provides an equal opportunity to all generators with similar costs to compete for loads. Moreover, in such transmission systems the market for new entry will also be more contestable. An increase in congestion and losses places generators at certain locations at a disadvantage relative to other similar cost generators which makes the market less competitive. This metric will measure the levelization of LMPs for each transmission topology using the standard deviation of LMPs across locations for the

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SPP footprint. All else being equal, a decrease in the value of this metric indicates an improvement in the competitiveness of the SPP market as a whole.

3) Improved access to economical resources participating in SPP Markets

This metric will provide a qualitative measure of competitiveness across the SPP footprint. It will analyze a generating unit's ability to compete within its own technology type. Capacity weighted LMPs will be calculated for generating plants of type wind, steam coal, combined cycle, and combustion turbine on an hourly basis and then averaged across the 25% of the largest hourly standard deviations.

4) Change in operating reserves

If an alternative transmission topology improves the power transfer across the SPP system, it has a potential to reduce the reliability reserve margin in the SPP system and therefore reduce the potential installed capacity requirements. The purpose of this metric is to monetize the value that alternative transmission topologies have in reducing the installed capacity requirements in the SPP footprint. This value could be monetized using the savings in capital and fixed O&M costs attributed to the corresponding reduction in installed capacity requirements.

5) TLR Reduction – Enabling Market Solutions

This metric is intended to capture the impact of the reduction in Transmission Loading Relief (TLR) calls associated with transmission improvements. It is important to note, however, that with the implementation of the Day 2 market in SPP, the need for TLR calls between SPP control areas will be eliminated because all congestion will be managed by the economic security constrained unit commitment and dispatch.

6) Limited export/import improvements

This metric quantifies the change in available transfer capability (ATC) that corresponds to an alternative topology with respect to the cost-effective plan. There are three categories of ATC changes that are of interest and are addressed by this metric:

a) From major generation centers within SPP to key delivery points on the boundary of SPP. This category relates to export capability improvements.

b) From key external receipt points at the boundary of SPP to load centers within SPP. This category relates to import capability improvements.

c) From key external receipt points at the boundary of SPP to key delivery points on the boundary of SPP. This category relates to improvements in the ability of SPP to accommodate wheel-through transactions.

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

This metric will evaluate the benefit of a proposed transmission topology on reducing the potential for market power associated with congestion induced load pockets (e.g. Narrowly Constrained Areas). When an electrical area becomes constrained due to one or more binding flowgates, a re-dispatch of certain generators will typically act to relieve this congestion. However, if the suppliers owning this generation are *pivotal*, that is without their assets there would not be enough generation available to relieve the congestion, a potential for market power arises. This metric will analyze these potential situations and relative to the Cost Effective Topology will calculate the benefit from an alternative transmission topology *m* in reducing the number of instances of *pivotal* suppliers. The metric is defined as the number of such pivotal supplier instances.

8) Improved economic market dynamics measured in the nodal security constrained economic dispatch model

This metric will analyze the effect of transmission expansion on reducing the per MWh marginal cost across the SPP footprint. Absent transmission congestion in an hour, the marginal unit is uniquely defined; with congestion, the number of marginal units will equal the number of binding constraints plus one. Among these marginal units, certain units act to relieve congestion by balancing other, typically less expensive marginal units' impact on the binding constraints. A reduction in the overall cost of such units should be considered an improvement in market dynamics.

9) Reduction in market price volatility

The deterministic modeling of a transmission topology using production cost models typically understates the volatility of resultant wholesale electricity prices. Load, fuel prices, generator and transmission outages, and allowance prices are all perfectly known. With an alternate transmission topology, the same set of inputs will result in a different dispatch of generating units but will not address the potential benefits of transmission projects in reducing price volatility due to alternate realizations of energy market economics. A production cost model (PCM) could be considered as a complex input-output model, whose major inputs include among other things, forecast of fuel prices, emission allowance prices, electricity demand, hydro conditions, and generator and transmission outages. The outputs among other things include locational electricity prices.

The volatility of electricity prices addressed by this metric reflects the magnitude of variability of electricity prices in response to variability of major inputs. The volatility must be measured for each topology and then compared across topologies.

10) Reduction of emission rates and values

If an alternative topology, results in a lower fossil fuel burn (or less coal-intensive generation) than the Cost-Effective Topology, then SO_2, NO_X, CO_2, and Hg emissions will be lower with the alternative topology in place. APC captures the cost savings associated with reduced SO_2, NO_X, and CO_2 emissions because the allowance prices for these pollutants

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are inputs to the production cost model simulations. However, since mercury is not currently a pollutant subject to an allowance price, changes in coal generation and the corresponding changes in mercury emissions are otherwise not captured in the 20-Year Assessment framework. This metric addresses that analytical deficiency and quantifies the changes in mercury emissions. This metric also quantifies the changes in SO_2, NO_X, and CO_2 emissions based on the 20-Year Assessment assumptions.

The mercury emissions from a given simulation can be easily calculated if the mercury content of the coal, the coal burn, and the mercury capture efficiencies of the coal units' pollution controls are known. The production cost tool directly reports the SO_2, NO_X, and CO_2 emissions. This metric is calculated simply as the difference between the cost-effective topology's emissions and the alternative topology's emissions (for each pollutant separately). The change in mercury emissions should be quantified in units of lbs/year and the change in SO_2, NO_X, and CO_2 emissions should be tons/year.

11) Transmission corridor utilization

An alternative transmission expansion plan *m* that effectively utilizes existing right-of-way (ROW) is preferable – all else equal - to those that do not. In addition, a topology that largely avoids environmentally sensitive areas is preferable – all else equal – to those that do not.[8]

This metric is really two sub-metrics. The first sub-metric measures the proportion of transmission expansion plan cost that *does not* effectively utilize existing ROW. The second sub-metric measures the proportion of transmission expansion plan cost that traverses environmentally sensitive areas. For both sub-metrics the plan costs should be discounted to present value (as the plan costs would be staggered over time and require conversion to present value).

12) Ability to reduce cycling of base load units

The purpose of this metric is to evaluate the benefit from reducing cycling of large[9] base load generating plants. For the purpose of this metric, a cycle occurs during any start-up to shut-down period each time a unit's output crosses or reaches the average output and then goes below this average minus a tolerance[10]. Relative to the Cost-Effective Topology, a transmission project that reduces the total number of cycles for a base load unit will reduce maintenance costs and in turn prolong the life span of the unit. If SPP has data on the relationship between the number of cycles and O&M cost or has a dollar value associated

[8] If *m* largely avoids environmentally sensitive areas by facilitating the location of fossil generation more closely to load centers, the avoided environmental cost of the transmission siting can be offset by the increased, adverse urban air quality impacts at the load centers (e.g., increases in ground-level ozone concentrations). This tradeoff should be kept in mind when considering the amount of transmission (project cost) that traverses environmentally sensitive areas.

[9] The Cutoff for Large units should be set by SPP stakeholders

[10] To account for small modulations in generation, SPP stakeholders should establish a percentage tolerance level such that a change in generation within this tolerance would not count as a cycle

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with excessive versus normal or ideal cycling[11], this metric can be monetized to arrive at a value to generators from reduced cycling.

13) Generation Resource Diversity

If an alternative transmission topology *m* results in a more diverse generation capacity expansion plan than the cost-effective transmission expansion plan there would be a benefit to ratepayers in that the power system could respond more flexibly to relative fuel price changes.

This metric is a semi-quantitative metric based on the generation mix (*energy basis*) from the production cost model simulation. For a given future, this metric is simply a comparison of the generation mixes (energy basis) from the cost-effective topology and an alternative topology. Both the annual generation mix and the *fuel-on-the-margin* mix are considered. Of particular interest is whether the gas-fired generation approaches or exceeds X% of the generation mix - this is because the level and volatility of gas prices are typically relatively high compared to the level and volatility of coal and nuclear fuel prices.[12] Excessive dependence on gas-fired generation – to the detriment of a more balanced dispatch of gas, oil, coal, and nuclear energy - exposes ratepayers to greater fuel price risk. Note that wind and hydro dispatch is fixed for a given future, notwithstanding curtailments.

14) Ability to serve unexpected new load

This metric measure the ability of an alternative transmission topology, to serve new load at levels that are different from those considered in the derivation APC. The metric tests two types of load changes – an overall incremental load in proportion to load forecast used in the development of each future and load shifts between major load centers.

15) Part of Overall EHV Overlay Plan

This metric will not be developed for ITP20, because ITP20 is the process for the development of the EHV Overlay Plan.

3.8 Deliverable

3.8.1 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 EHV transmission plan that is robust, being adaptable for all of the futures considered, and adding greater incremental value than incremental cost.

[11] Excessive, Normal and Ideal levels of cycling should be defined by SPP stakeholders
[12] Oil prices are also volatile but oil-fired generation is small relative to coal, gas, and nuclear.

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3.8.2 Report

The deliverable for the 20-Year Assessment will be a single transmission plan 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 20-Year ITP Report.

4 Ten-Year Integrated Transmission Planning

4.1 Purpose

The second phase of the ITP process is the 10-year planning horizon assessment. This 10-Year Assessment is a value-based planning approach that will analyze the 10-year out Transmission System 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 10-Year Assessment will be utilized in integrating the ITP20 with the100 kV and above facilities to incorporate needs such as the following: a) resolving potential criteria violations; b) the mitigating known or foreseen congestion; c) improve access to markets; d) the staging of transmission expansion; and e) improving interconnections. In the 10-Year Assessment the scenarios considered in the 20-Year Assessment will focus on the combination of events that are determined to be most likely occurring within the 10-year horizon. This assessment is not intended to review each year in the planning horizon, but instead focus on the horizon year. Economic and reliability analyses will be utilized as a way to further refine and establish the staging of the projects.

4.2 Futures Evaluation

Due to the uncertainties involved in forecasting future system conditions, a number of futures will be considered that take into account multiple variables. Consideration of multiple futures will provide for a transmission expansion plan that will evolve as economic, environmental, regulatory, societal, and technological changes arise that affect the industry.

The futures used in the ITP process will be developed by SPP staff and stakeholders. Consideration of these futures will allow the ITP to take into account variability by considering the economic, environmental, governmental, 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.

4.3 Data Requirements

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 NDA's have been signed.

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4.3.1 Wind Farms

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, locations, and profiles of these additional wind farms are approved by the ESWG.

4.3.2 Interaction with ERCOT & WECC

DC ties connect the SPP to the WECC and ERCOT systems. SPP will use historical DC tie usage profiles as a best approximation for the respective DC tie.

4.3.3 Working Group Review of Modeling Data

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

Comment [rah4]: wording

4.4 Assumptions

4.4.1 Load Forecast Assumptions

The Study 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 through the MDWG for appropriate load forecasts to use in each of the pricing zones (modeling area) for the modeling footprint. Energy forecasts will be provided by the ESWG and other SPP staff contacts.

Comment [XPR15]: Is this a sentence? Is this trying to say the SPP staff will use MDWG data to obtain load forecasts? Please clarify.

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.

4.4.2 Fuel Prices

The price assumptions for fuels will be an important driver for the Study. The ESWG will review and approve the fuel prices used in the Study.

4.4.3 Emission Prices

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

4.4.4 Modeling Footprint

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The modeling footprint will include the entire SPP region and nearby areas. Other areas may be added to the model as described in the study scope.

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4.4.5 Import/Export Limits

The ITP will focus on benefits to the SPP region. The imports and exports will be set and benchmarked using hurdle rates and expected external system conditions for ten years in the future. The ESWG will review the hurdle rates.

4.5 Modeling Methods

4.5.1 Steady State Analysis

Power flow models with a market dispatch under coincident peak load and off-peak load will be developed. Steady state analysis will be conducted using output from the economic models as a starting reference for load and generation dispatch.

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4.5.2 Power Flow/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 publicly 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.

4.6 Ten-Year ITP Process

4.6.1 Constraint Selection

Staff will review the existing NERC Book of Flowgates (BoF) and determine what (if any) constraints need to be added or deleted from the list of constraints (event file) for the economic model runs. The constraint study should determine what additional constraints are needed in the 10 year models with the additional load and resources.

TWG will review the constraint selection analysis.

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4.6.2 Screening Analysis

SPP will start the screening analysis using prototypes which are developed based on previous 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 futures.

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4.6.3 Security Constrainted Unit Commitment and Economic Dispatch Analysis

SPP staff will use 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.

4.6.4 Solution Development

During the process of the 10-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, congestion, LMP variation and trapped generation. 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 will be placed in the economic model, and a full economic assessment will be performed. The results from the analysis will be used to determine benefit metrics. These benefit metrics may be a subset of the metrics used for the ITP20, which will be reviewed by appropriate working groups.

4.7 Deliverable

4.7.1 Report

The results from the ITP 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.

4.7.2 Recommended 10-Year Plan

This 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.

4.7.3 Staging and timing of project implementation

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 justification. NTCs will be issued for the ITP10 plan elements in accordance with the Tariff, Attachment O, Section VI and SPP written procedures (see Business Practice 1.15[13]). ATPs will be issued for the ITP10 plan elements in accordance with SPP procedures.

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

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5 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.

5.1 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.

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5.2 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.

5.3 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.

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.[14]

5.3.1 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)).

5.4 Assumptions

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;

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

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- o 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.

5.4.1 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.

5.5 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.

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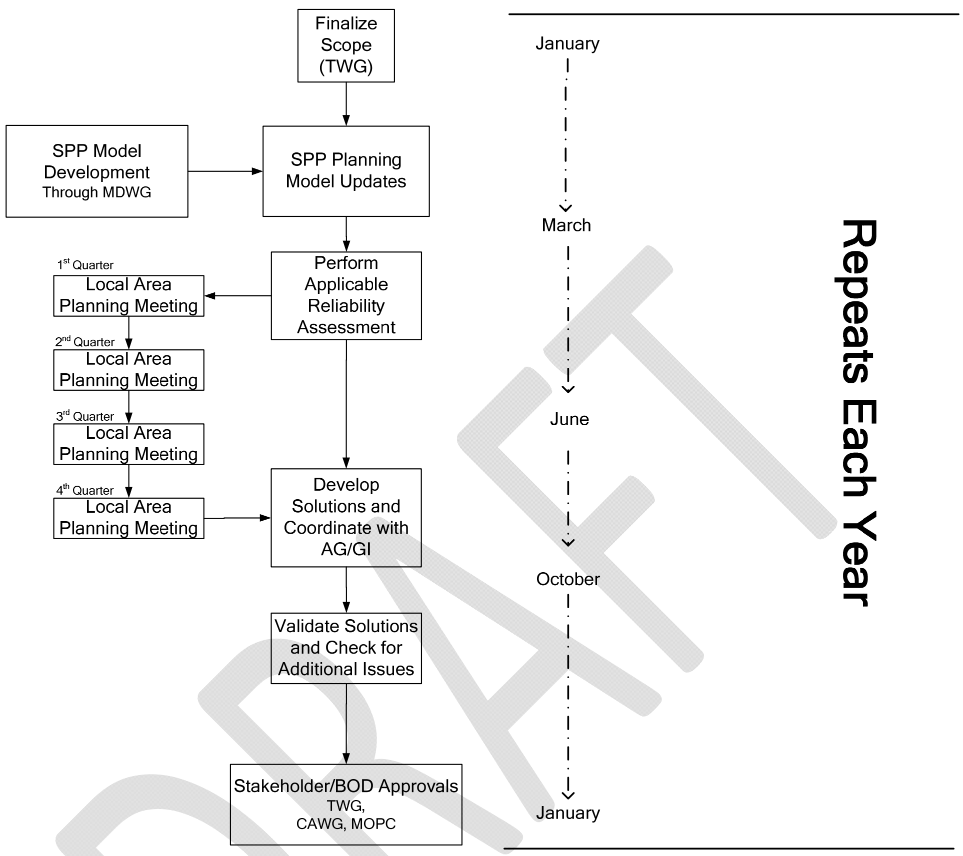

Details regarding key assumptions, models, project data, specific tasks, outstanding issues, progress reports, maps, and study results are available on the SPP web site.

5.5.1 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

Relationship-Based • Member-Driven • Independence Through Diversity

Evolutionary vs. Revolutionary • Reliability & Economics Inseparable

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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[15] 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[16];
- 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 ITP 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:

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

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- 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
- 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 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

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[17]:

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.

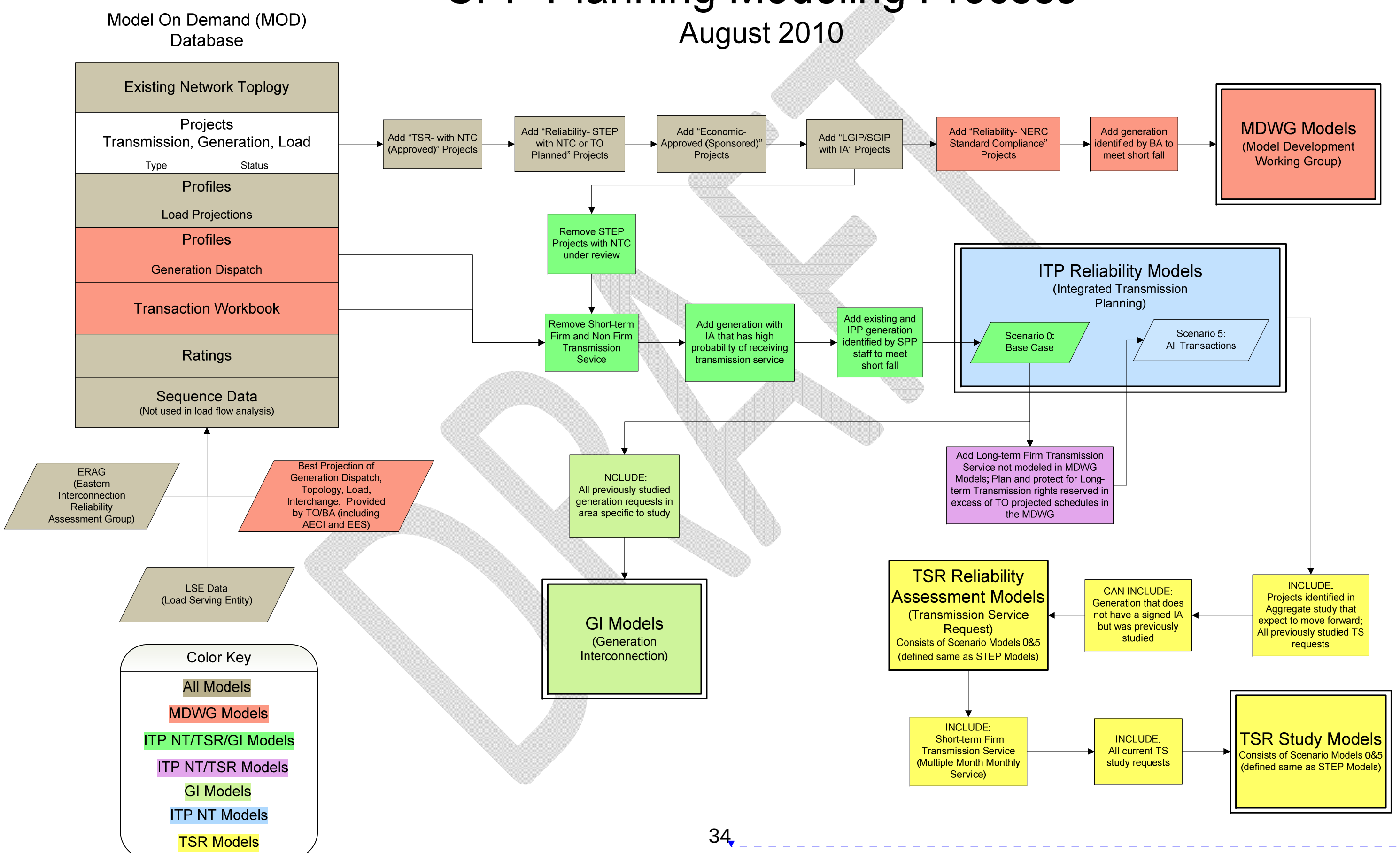
SPP uses scenarios to evaluate reliability. The number of scenarios is determined each year and approved by the TWG.

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

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

SPP Planning Modeling Process

August 2010



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5.5.2 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.

5.5.3 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.

5.5.4 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[18]

5.5.5 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.

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

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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.

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5.6 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:

- 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.

5.6.1 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.

6 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.

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7 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.

7.1 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.

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8 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			

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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

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9 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

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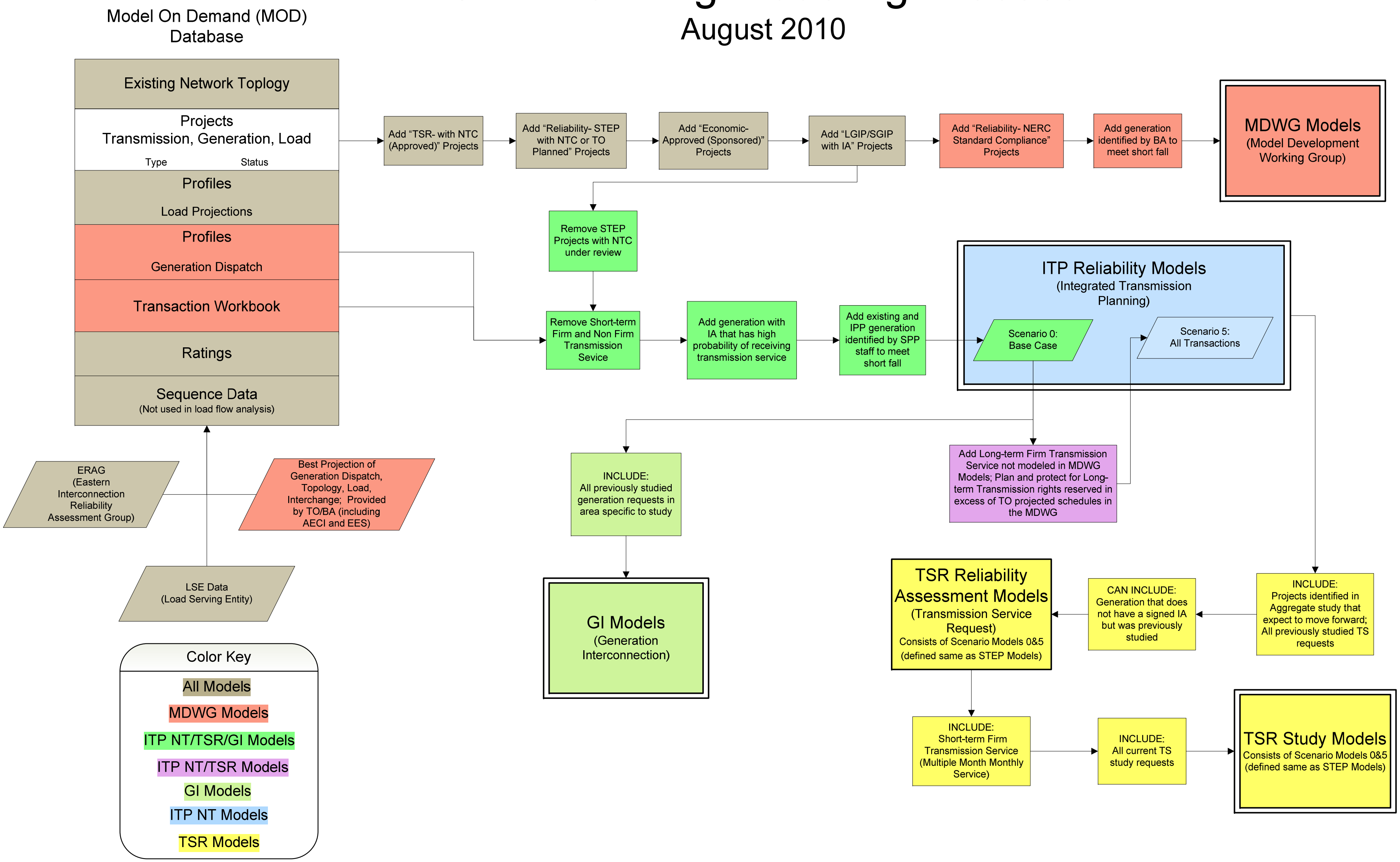
3. specificity means location is not critical and generators may be selected from the fleet the entity has authority to run. The ramp rate of the generation must be capable of relieving the overload or voltage issue within the time allowed as specified in the TOG.
4. A TOG must not cause a violation elsewhere on the Transmission System.
5. 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 34: [1] Deleted	jsm0111	4/28/2011 10:13:00 AM

SPP Planning Modeling Process

August 2010



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