BLACK HILLS/COLORADO ELECTRIC, LLC

Transmission System Planning Methodology, Criteria and Process Business Practice

April 8, 2010

Table of Contents

Introduction

Black Hills/Colorado Electric, LLC ("BHCE"), referred to hereinafter as the "Transmission Provider" or "TP", owns and operates certain transmission facilities with transmission service pursuant to a FERC-approved Open Access Transmission Tariff ("OATT"). The methodology, process and criteria described herein are used to evaluate the BHCE transmission system, ensuring system reliability is maintained throughout the planning horizon. Reliability, by definition, examines the adequacy and security of the electric transmission system.

The Federal Energy Regulatory Commission (FERC) Order No. 890 requires the TP to explain how they will treat retail native loads, in order to ensure that standards and processes are consistently applied to all customers. Consistent application of the TP planning process, standards, methodology and criteria for all customers (i.e., retail, network and point-to-point) is ensured through the coordination, openness and transparency of TP planning process. All customers are treated on an equal and comparable basis using the transmission system planning process, methodology and criteria described herein. All customer data is included in the planning analysis without regard to their classification. The TP transmission system planning process is designed to be transparent, open and understandable. The information described herein reflects existing practice, with the addition of new processes that encompass Order 890 transmission system planning requirements. For example, the TP planning process is being expanded to include input from stakeholders and other interested parties during the planning stage. As described in Attachment K to the OATT, a Transmission Coordination and Planning Committee ("TCPC") will be established to facilitate a coordinated, open and transparent planning process.

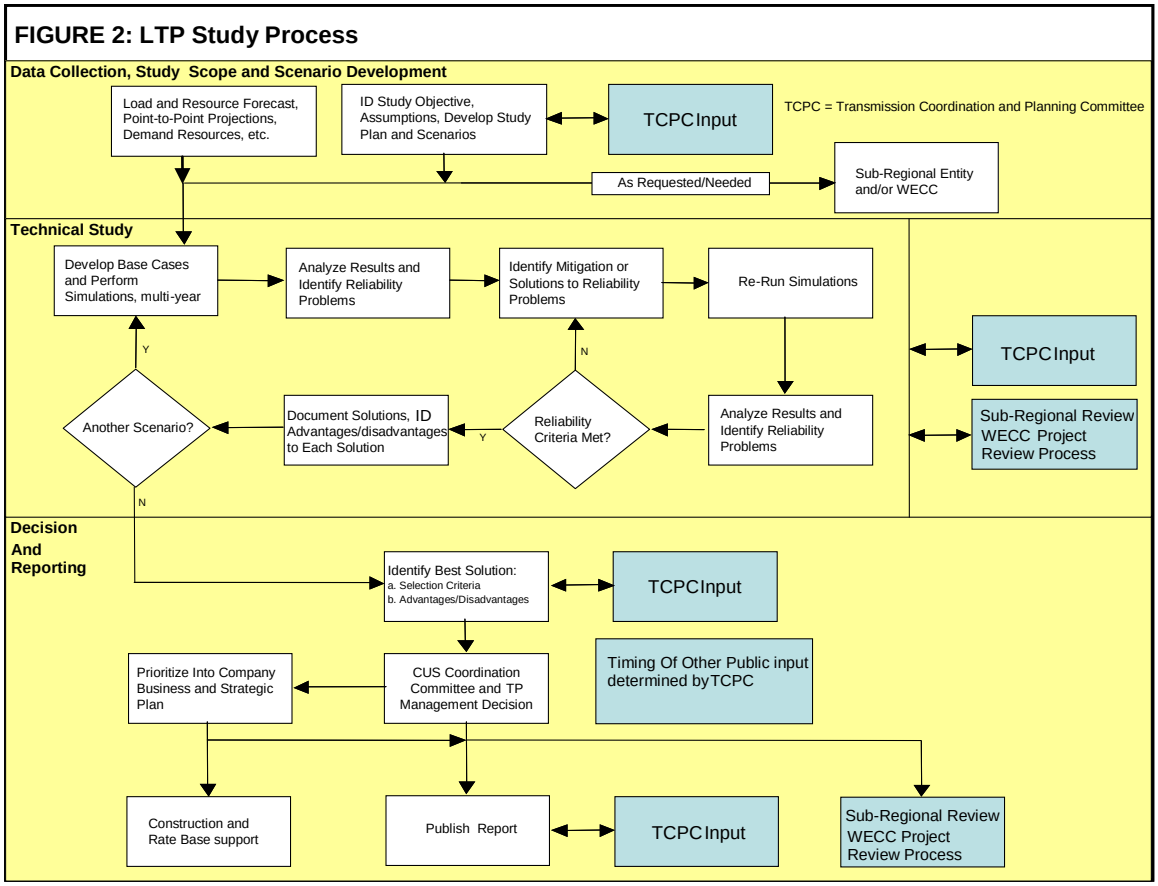
FERC Order 890 makes a distinction between the transmission system planning for load due to customers' needs (i.e., system planning) and planning for new generation interconnection. The TP adheres to the FERC Large Generation Interconnection Procedure ("LGIP") and Small Generation Interconnection Procedure ("SGIP") requirements to study generation interconnection requests. In studying a request for transmission service, the TP follows its tariff requirements as provided on the TP OASIS Website at http://www.oatioasis.com/BHCT.

Transmission Provider Electric Transmission System

The TP electric transmission system consists of approximately 194 miles of high voltage (115 kV) transmission lines located in southern Colorado. The transmission system generally follows the Arkansas River Valley from the Royal Gorge west of Canon City to the city of La Junta, Colorado.

Transmission Provider Planning Process

The Local Transmission Plan ("LTP") study process is depicted in the following flowchart.



The TP will follow a four (4) quarter study cycle that follows the process shown in Figure 2 above. This process will be used to develop a 10-year LTP. The planning process steps (i.e., Data Collection, Study Scope and Scenario Development, Technical Study, Decision and Reporting) are fully integrated and produce the LTP. This process is fully described in the following sections.

Timeline

The typical timeline for the LTP study cycle is shown in the following table. The Transmission Coordination and Planning Committee[1] ("TCPC") will meet quarterly to provide input throughout the LTP study process.

Typical Timeline - LTP Study Cycle

Quarter	Planning Steps	Data Collection	TCPC Meetings
Q4	Study Scope & Scenario Development	Open	X
Q1	Technical Study	Optional	X
Q2		Closed	X
Q3	Decision & Reporting		X

This timeline displays the approximate time dedicated to each of the planning steps and when forecast data will be collected. Data that is collected will fall into one of three time periods for inclusion into the TP planning process - "Open", "Optional" or "Closed". All data collected during the Open time period will be included in the study assuming the data is complete. Data obtained during the Optional time period may or may not be included in the study if it is not complete or the Technical Study has progressed to a point where including this information is not practical. The TP will consult with the TCPC in making this determination. Data collected during the Closed time period of the annual cycle will be compared to the data used in the technical analysis and any notable changes will be discussed in the final LTP report.

[1] TCPC is a stakeholder committee that meets regularly with the TP to provided input and comments throughout the LTP study cycle. Membership is open and communication is open and transparent. For more information see Attachment K to the OATT on the TP OASIS Website (http:/www.oatioasis.com/BHCT/).

Regional & Sub Regional Participation

The TP's participation in regional and sub-regional planning activities will be broad, ranging from providing data to participating in studies and committees. The TP transmission system data, assumptions and LTP will be shared with interconnected transmission systems, sub-regional and regional entities. The TP base case data and LTP will be provided to other Transmission Providers when appropriate.

The TP will provide its LTP study data and assumptions to sub-regional and regional committees[2] that are responsible for building databases and then using these databases for load and resource assessments or for operating and planning reliability studies. This is an annual process that requires the TP to provide basic transmission data, load forecasts and generation dispatch information to be shared and included in the databases used by regional and sub-regional planning entities. The TP will participate in these forums as appropriate.

The TP will provide its LTP to the WECC, Colorado Coordinated Planning Group ("CCPG"), WestConnect and other sub-regional entities as appropriate. In the sub-regional context, the TP is an active participant of CCPG and WestConnect. The TP will submit its data, assumptions and LTP to CCPG and WestConnect as required for inclusion in all applicable sub-regional transmission plans. The TP will actively participate in the CCPG and WestConnect planning process to ensure data and assumptions are properly represented in all applicable sub-regional plans. When appropriate the TP will provide its LTP to WECC or other regional entities.

The TP may participate in sub-regional and regional transmission planning studies as appropriate to ensure data and assumptions are coordinated. These studies may be focused on integrating new transmission lines into the regional transmission network or a broad planning study of regional or sub-regional transmission needs. The TP's participation in these studies will be guided by the intent of the study and how the TP transmission system might be affected.

Transmission Planning Process and Basic Methodology

Below is a discussion of the TP's LTP study process and basic methodology that is used to formally analyze the Common Use System. By application of this methodology, the TP ensures that a reliable transmission system exists to serve network customer load and firm point-to-point transmission service obligations. The TP's methodology is intended to define operating conditions that fail to meet reliability criteria and then identify mitigations or solutions (e.g., transmission and non-transmission[3]) that mitigate any criteria violations. The operating conditions are for a specific instant in time, such as peak load conditions, and are not an integrated time period, such as an hour, day, month,

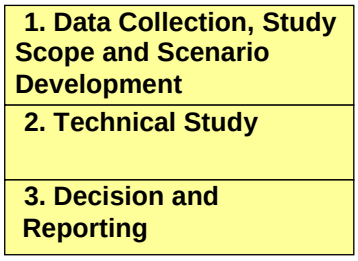
[2] For example: WECC System Review Work Group (SRWG), WECC LRS Subcommittee, WECC Technical Studies Subcommittee, Colorado Coordinated Planning Group, etc.
[3] Demand-side resource, generation, interruptible load, etc.

etc. The TP's basic process and methodology described below is focused on transmission reliability and not economic studies that can be requested by stakeholders.

The TP's goal is to design a reliable, least cost transmission system that will perform under expected system conditions wherein customer load can be served reliably throughout the planning horizon.

LTP Study Process

The TP planning process includes the three steps shown in the graph to the right. These steps are (1) Data Collection, Study Scope and Scenario Development, (2) Technical Study, (3) Decision and Reporting. How these steps are integrated to formulate the LTP is shown in Figure 2 above and further described below. The transmission lines monitored in the LTP study may range in base voltage and may be operated in either a networked or radial configuration.



The LTP study process involves modeling forecasted customer demand, identifying area reliability criteria violations, evaluating possible violation mitigation options and selecting solutions that meet the BHCE transmission system reliability needs. The LTP study evaluates the transmission system reliability using a 10-year planning horizon. The planning effort will consider transmission and non-transmission alternatives to resolve any reliability criteria violations within the BHCE transmission system. The TP's process is flexible, involves stakeholder input and is intended to develop an LTP that:

- Responds to customers needs;
- Is low cost (e.g., Total Present Value Revenue Requirement, Rate Impact, etc.);
- Considers non-transmission and transmission alternatives;
- Assesses future uncertainty and risk;
- Promotes the TP commitment to protecting the environment;
- Includes input from the public and other interested parties;
- Provides adequate return to investors;
- Complements corporate goals and commitments;
- Meets all FERC and WECC Standards;
- Meets all applicable state regulatory expectations;
- Meets regional and sub-regional planning requirements;
- Satisfies all requirements of FERC Order 890; and
- Conforms to applicable state and national laws and regulations.

Data Collection, Study Scope and Scenario Development

This first phase of the LTP study process, as can be seen in Figure 2 above, requires coordination and input from the TCPC. The TP will work with the TCPC to review non-commercially sensitive data collected, as well as identify the study scope and pertinent scenarios that should be studied in order to meet stakeholder needs. The TCPC will

provide input into the TP transmission planning process pursuant to FERC Order 890 Transparency requirements. Information regarding the TCPC can be found in Attachment K to the Transmission Provider OATT located on the BHCT OASIS Website at http://www.oatioasis.com/BHCT/.

Data Collection

Up-to-date and accurate input data is critical for producing meaningful results from any planning study. To this end, the TP will request the following data from all Transmission Customers during the first phase of the LTP study process:

Historical Load Data: Monthly energy, peak load data for the prior calendar year. Monthly energy, peak load data for the current year as it becomes available.

Load Forecast Data: Ten (10) year monthly energy, peak load and resource and minimum load and resource forecast. Ten (10) year annual energy, peak load and resource and minimum load and resource forecast.

Point-to-Point and other Transmission Customers: Ten (10) year forecast of projected use or rollover of existing reservations. Additionally, any expected additional reservations should be provided. All forecasts shall specify a Point of Receipt and Point of Delivery by bus.

Generation Forecast Data: Technical engineering data for all generators and interconnection facilities, peak capabilities (MW/MVAR) and maintenance cycle.

Demand Response, Demand Reduction, Conservation, DSM: Ten (10) year projected load reduction or alteration due to the listed initiatives.

Interruptible and Other Load: Peak load forecast with and without the interruptible portion of the forecast data applied.

Other Supply Sources: Monthly energy, peak load data for electrical supply sources not from generators.

A request for this data will be sent by the TP to all Transmission Customers no later than close of business Friday of the second full week of January. The data will request will specify the date that all data is due to the TP. The data will be submitted via an Excel workbook which will be posted on the TP OASIS website, along with instructions regarding the submittal of data as well as the data format.

Study Scope and Scenario Development

The TP uses scenario planning and not probabilistic planning for developing the electric transmission system plan. The TP may, however, use probabilistic assessment methods within a defined scenario to evaluate uncertainty

A scenario represents a "snapshot" in time that depicts a specific condition, for example: peak summer load, minimum area generation, maximum import, etc. Each scenario should be realistic and be designed to provide maximum stress to the transmission system regardless if it causes inadequate transmission system performance as measured against established criteria. Since a large number of combinations of load, generation and export/import conditions exist, careful consideration must be given to design each scenario to depict a future load and generation dispatch pattern that stresses the transmission system. Experience has shown that the BHCE transmission system is stressed during heavy summer conditions with minimum exports and during light load conditions with maximum export conditions. A good study plan and realistic scenarios will help ensure the LTP identifies upgrades which will ensure the transmission system remains reliable under all operating conditions.

The TP basic methodology is to develop the base scenarios to study and then to develop uncertainty scenarios from these base scenarios. This methodology is described in more detail below.

Base Case Scenarios

Base case scenarios will be used to examine the transmission system under a variety of future assumptions for a specific period of time. Varying the amount, type and location of generation, the load level and export/import conditions are all important in defining a scenario. These assumptions include, but are not limited to the following:

- Load Forecast (e.g., year to study)
- Load Condition to Study (e.g. season, peak load or light load, etc.)
- Generation Available (e.g., generation additions/changes)
- Generation Dispatch Conditions (e.g., how is the generation operated)
    - Different types of generation to determine how generation responds to outage conditions
    - Generation location and magnitude to determine transmission stress
    - Higher generation levels to cause more power to be exported out of the TP transmission system. Lower generation levels with high imports
- Transmission System Elements Available (e.g., transmission element additions/changes)
- Transmission System Configuration (e.g., what elements are out-of-service)

Even though new generation interconnection projects follow the OATT LGIP/SGIP, the study results from generator interconnection projects cannot be ignored in the LTP study. The addition of new generation to the BHCE transmission system can affect the flows throughout the system. Additional power flows from the new generation, and flow changes due to transmission system upgrades, may require additional transmission system upgrades. The TP, with input from the TCPC, will consider scenarios including queued generator interconnection projects with associated transmission facilities or develop uncertainty scenarios which include these projects.

Uncertainty Scenarios

The uncertainty scenarios are intended to recognize that the future, as assumed in the base case scenarios, is not known. This uncertain future creates risk, which may be quantifiable or non-quantifiable. Risk may be expressed as a dollar cost or other impact. The base scenarios must make assumptions about future conditions, but the uncertainty scenario helps with understanding the risk associated with those assumptions. The purpose of any uncertainty scenario is to develop information about the cost and electrical performance associated with that scenario so that an informed decision about future transmission investments, and the associated risks, can be made.

Technical Study

The technical study is the second phase in the LTP study process. The technical study will begins by developing base cases which reflect the base case scenarios identified in the first phase. This may require developing several base cases to span the 10-year planning study horizon. For example, to study summer peak conditions in the years 2010 and 2015, two distinct base cases that reflect the load, generation and transmission facility changes and/or additions for the specific year would be required. Developing a base case accurately depicting the base case scenario is critical and can take a significant amount of work and time to develop.

Once the base cases have been developed, the technical study is performed to examine the reliability of the CUS to meet the forecasted load and transfers. The TP uses a sophisticated computer model (i.e., Siemens PTI PSS/E) to simulate generator output, transmission line flows, electrical equipment operation, customer loads and power transfers. The technical study quantifies transmission system performance by measuring the bus voltage, equipment loading, reactive power requirements, system frequency and other electrical parameters and comparing them against established reliability criteria. If inadequate performance is observed, a solution or mitigation (e.g., transmission or non-transmission) is proposed, and the base case is modified to include the proposed solution. The simulation is repeated and system performance is again measured against established criteria. This circular process is repeated until the system performance meets or exceeds reliability requirements. It should be noted, that at the conclusion of the study, only a single solution will be defined and implemented, so once a solution is defined for a scenario, it must be included in all scenarios to ensure that it does not cause negative impacts under all conditions.

A model is developed that includes technical data for generation, transmission lines, electrical system equipment and customer load levels and geographic distribution. The basic methodologies for developing the base case data are described below.

- Transmission: The TP will use the existing transmission infrastructure as a starting point. This data will be reviewed and any updates to the existing transmission data will be coordinated with the TCPC and included in the base case. Any transmission facilities under construction will be included in the base case. Proposed transmission additions not under construction will not be included in the initial base case unless

both the TP and the TCPC agree that they should be included. These projects may be included in one or more uncertainty scenarios.

New regional transmission projects that affect the BHCE transmission system will be included if the project is in Phase 2 of the WECC Three Phase Rating Process and both the TP and the TCPC agree that it should be included. These projects may be included in one or more uncertainty scenario if they are not included in a base case.

- Generation: The TP will use the existing interconnected generation as a starting point. The generation data collected in the first phase will be reviewed and any updates or changes will be coordinated with the TCPC and included in the base case. Queued generation projects may be included, along with any associated transmission additions and upgrades, upon agreement of both the TP and TCPC. Queued generation projects may be included in one or more uncertainty scenarios.

- Demand Response Resources: The TP will review the demand response resource forecasts obtained in the first phase with the TCPC for inclusion in the base case. One or more uncertainty scenarios may analyze adjustments to the provided forecasts.

The technical analyses will use different engineering studies to evaluate the system performance. These studies are designed to use different engineering perspectives to ensure system reliability is maintained. These methods include, but are not limited to, the following:

- Steady-State Powerflow Analyses
- Post Transient Steady-State Powerflow Analyses (or Steady-State Post Fault Analysis)
- Transient Stability Analyses (or Dynamic Analyses)
- Fault Duty Analyses
- Reactive Margin Analyses

A study of the transmission system under static conditions is a steady-state power flow study, and a study over time[4] is called a transient stability study. The steady state power flow analysis is a static evaluation of a local area transmission system that examines the transmission system under normal operating conditions with all lines in-service and with single and multiple transmission lines or elements out-of-service (i.e., N-1, N-2, N-1-1, etc. conditions). Note that the "-1" in N-1 represents the number of transmission elements that are out of service. A transient stability study (i.e., a dynamic simulation

[4] The Siemens PTI PSS/E program completes a transient stability study by running the computer model repeatedly over time and recording how the generation and transmission elements change over time as the result of an outage. A sequence of results is produced that depict how the generation and transmission system equipment responds to this outage condition. The time step must be very small to accurately capture transmission system changes because generation and load are matched instantaneously. For example, a dynamic study runs a powerflow simulation of the system, with progressive "real" time adjustments, every ¼ cycle or 0.00417 seconds. Thus to make a 5 second study, the program must be run 1200 times.

study) evaluates the transmission system performance on a progressive time dependent basis. These studies evaluate credible outage events to determine if the transmission system will recover to acceptable steady-state operation after the outage. The studies include an assortment of outage events that are intended to provide a thorough test of the reliability of the transmission system. After a power flow simulation is completed, a search of the simulation results for unacceptable thermal overloads and voltage excursions is made. Unacceptable transmission system performance must be corrected by including transmission and non-transmission (e.g., demand-side resource, generation, etc.) fixes into a second simulation. Additional mitigation or fixes are included in the simulation until a valid solution is found. A valid solution is one that meets the reliability criteria describe below. System performance information for this scenario is identified and retained for comparative analysis between scenarios during the decision step.

The credible "worst case" single and multiple fault events must be simulated to determine if the transmission system will recover to acceptable steady-state operation. A dynamic simulation includes an assortment of outage events that are intended to provide a thorough test of the reliability of the transmission system.

From these studies the changes in system steady-state and transient voltage levels after the loss of a single line, multiple lines, or generating units; changes in the line and equipment thermal loading conditions; changes in Volt-Ampere reactive ("VAr") requirements (voltage support); and unacceptable frequency excursions are evaluated. All relevant reliability criteria are applied in these evaluations. Reliability criteria are defined in the Reliability Criteria section of this document. Any violations of reliability criteria are noted and will require mitigation.

The TP will also conduct fault duty and reactive margin studies as needed. A fault duty study is a study of electrical current interrupting devices (e.g., breakers) to ensure the device can open under maximum load conditions. When a fault or short circuit occurs on a power line, the protective relay equipment detects the increased current (i.e., fault current) flowing in the line and signals the line's circuit breakers to open. When the circuit breakers open, they must be capable of interrupting the full fault current. The worst-case fault current is commonly referred to as the "fault-duty". A reactive margin study is a study to ensure that the transmission system has sufficient voltage control to maintain adequate voltage levels.

Decision

An objective of a system planning study is to evaluate the range of potential transmission and non-transmission (e.g., demand side management, generation, conservation, etc.) solutions within the technical study and determine the best solution. The primary purpose of the decision phase is to provide descriptive information about the system and the problem (risk, cost, etc.) and identify the best solution or mitigation to resolve the problem. The TP will use selection criteria and weighting to provide a ranking of the solution(s). The TP will seek input from the TCPC in identifying and weighting the criteria to use in selecting the appropriate solution. This information along with documented advantages and disadvantages of each solution will be used to aid in

selecting best solution or mitigation that achieves the objectives of the transmission plan. Selection criteria may include, but is not limited to, the following:

- Total present value of upgrade costs
- Time available to implement upgrade
- System performance with each solution
- Probability of scenario requiring a solution
- Environmental assessment and/or costs
- Non-quantifiable assessment

The primary purpose of the selection criteria is to provide descriptive information (e.g., costs, risks, etc.) about the system and solution(s) needed to resolve the problems. This information can be ordered or weighted so that stakeholders can understand the differences between the scenarios and provide input to the TP. TP management can then use this information to make an informed decision regarding future transmission investment to serve future network load and point-to-point requests. Once approved, the solution will be prioritized into the TP Business and Strategic Plans.

Reporting

The TP, with input from the TCPC, will develop the LTP which will describe the study plan, scenarios, technical studies, selection criteria and selected solutions. The final LTP will be published on the TP OASIS web page.

Load Forecast Methodology

Pursuant to FERC MOD-016, the TP will obtain load forecasts from Load Serving Entities ("LSE") within the TP. A summer and winter peak load forecast will be collected from the LSE's within the TP for use in the study. Additionally, the TP will request a minimum load forecast for use in light load scenarios. The LSE's load forecasts will be summed, assuming they are time coincident, to calculate the TP area load forecast. The loads within the TP are metered and tracked. That is, the loads are well defined and monitored. If the LSE and TP load forecast, based on actual historical loads, results are significantly different, the TP will attempt to reconcile these differences. If the TP cannot reconcile these differences, the TP will choose which forecast to use in the study.

The TP area load forecast will be adjusted to reflect demand response resource reductions, conservation reductions and other appropriate peak load modifying sources.

Once the TP area load forecast is developed, this forecast is disaggregated to the respective transmission system load buses. There are two types of load buses – (1) a load bus where the load does not change over time (e.g., a single large industrial load bus); and (2) a load bus where the load changes over time (e.g., residential load). The TP will

use its knowledge of load characteristics along with historical loading observations to estimate the individual load bus data in time. The load bus forecasts are summed and compared to the TP load forecast. If the two forecasts do not match, the TP will adjust the variable bus load forecasts until the two forecasts match.

WECC Annual Study Program

In addition to the TP's own LTP study, the TP participates in the WECC Annual Study Program. This program examines the reliability of electric transmission lines that are instrumental in moving electricity across the TP system from sources of supply inside and outside the TP system to markets inside and outside the TP system. A detailed simulation model[5] is used for steady state and dynamic event analysis that assesses electric transmission stability before and after a loss of a critical electrical element (e.g., transmission line).

Two types of study assessments are conducted - Operating Transfer Capability ("OTC") studies and Bulk System Planning Studies. The distinction between these studies is that the OTC study establishes the next season's maximum transfer capacity for selected electric transmission paths and the planning studies evaluate the bulk transmission system's adequacy and security 2-10 years into the future. The Annual Study Program requires that each year approximately ten detailed studies be conducted to assess bulk electric transmission reliability. The mix of operating and planning studies varies each year.

If conducting a seasonal OTC study, the TP will follow the WECC policy outlining the process, procedures and assumptions to use for OTC studies. OTC studies are only required on WECC Rated Paths. The TP does not currently operate a qualified WECC rated path.

The Bulk System Planning Study originates through the WECC System Review Work Group ("SRWG") annual planning program. The WECC study follows the same process as the OTC studies, except the season can range from 2 to 10 years in the future and may include proposed new facilities. The goal of the planning study is to examine the reliability of the future transmission system under prescribed seasonal loads, generation patterns, and various outage conditions and to identify appropriate upgrades and/or new facilities to maintain bulk system reliability into the future.

Economic Planning Study

Pursuant to FERC Order 890, stakeholders may request an Economic Planning Study. The purpose of FERC Order 890 Economic Planning Studies is to ensure that customers may request studies that evaluate potential upgrades or other investments that could

[5] The TPs model the WECC transmission system using the Siemens PTI PSS/E software. The TP base case data includes 69 kV and 230 kV transmission system data.

reduce congestion or integrate new resources and loads on an aggregated or regional basis (e.g., wind developers), not to assign cost responsibility for those investments or otherwise determine whether they should be implemented. This is different than a proposed new generation interconnect study in that an interconnect study is to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the TP's transmission system.

A request for an Economic Planning Study will use the methodology and process as outlined in Attachment K of the OATT.

Criteria

The TP reliability criteria, NERC/WECC[6] regional reliability criteria (hereafter called Reliability Standards), FERC[7] Standards and industry standards (e.g., IEEE Standards) are the basis for the TP transmission planning criteria. This section describes these criteria.

Reliability Criteria

Electric transmission reliability is concerned with the adequacy and security of the electric transmission system. Adequacy addresses whether or not there is enough transmission capacity, and security is the ability of the transmission system to withstand contingencies (i.e., the loss of a single or multiple transmission elements). The TP uses two types of reliability criteria as shown below:

- TP Internal Reliability Criteria. A set of technical reliability measures that have been established for the safe and reliable operation of the CUS.
- FERC Standards and WECC Reliability Criteria. A set of minimum performance standards for system performance following a credible outage event on the transmission system.

The TP uses these criteria in evaluating the need for a modification or addition to transmission facilities and/or a modification to, or addition of generating facilities. The TP will use these reliability criteria as needed to fully evaluate the impacts of transmission facilities, generating facilities or loads on the BHCE transmission system. The TP may augment these criteria with other standards such as, but not limited to, the ANSI and IEEE standards.

The TP planning process ensures that changes which either directly or indirectly affect the BHCE transmission system will not materially reduce the reliability to existing

[6] WECC is in the process of removing standards that duplicate the FERC Standards; so only the more stringent WECC criteria will remain.
[7] The FERC Standards are implemented by NERC.

customers. The BHCE transmission system must provide reliable high quality service to all customers.

Internal Reliability Criteria

The TP Internal Reliability criteria are used for reliability performance evaluation of the electric transmission system. Steady-state implies the condition on the transmission system before an outage, or after an outage and after switching occurs, regulators adjust, reactors or capacitors to switch, and generation stabilizes (typically three minutes or more). This latter condition is also called post-fault reliability requirements.

These criteria support the FERC Standards and WECC Reliability Criteria that disallow a blackout, voltage collapse, or cascading outages unless the initiating disturbance and corresponding impacts are confined to either a local network or a radial system. An individual project or customer load may require an enhanced reliability requirement.

The TP plans that the BHCE transmission system to provide acceptable voltage levels during system normal and outage conditions. Areas of the BHCE transmission system that are served by radial transmission service are excluded from single contingency evaluation.

Steady State, Transient and Post-Transient Voltage Criteria

The TP follows the voltage limits as outlined in the Colorado Coordinated Planning Group's Voltage Coordination Guide ("VCG").

- The VCG defines "Acceptable Voltages" as between the range of 0.95 to 1.05 per unit. "Acceptable Voltages" are used by the TP as the steady state voltage criteria. This criteria is based on the assumption that all switching has taken place, all generators and transformer Load Tap Changer's ("LTC") have regulated voltages to set values, and capacitors or reactors are switched.

- Transient voltage criteria require that the first-swing voltage at all buses shall not exceed 0.70 per unit.

- The VCG defines "Emergency Voltages" as in the range 0.9 to 0.95 and 1.05 to 1.10 per unit. "Emergency Voltages" are used by the TP as the post fault voltage criteria. This criteria is based on the assumption that only automatically adjusting equipment has operated, such as generator excitation systems, automatic LTC's, automatically switched reactors and capacitors.

Transmission Equipment Rating and Loading

Transmission facility ratings are determined by BHCE's Facility Ratings Methodologies.

Facility Connection Requirements

Each Transmission Owner is required per NERC Reliability Standard FAC-001-0 to have documented facility connection requirements. These documents dictate the specific requirements for connecting new facilities to the BHCE transmission system.

Remedial Action Scheme (RAS) and Overload Mitigation Scheme (OMS) Application

The TP may consider a RAS or an OMS application to protect the CUS against certain types of events, but each application will be evaluated on a case-by-case basis with no assurance that a RAS or an OMS application will be acceptable.

- An OMS may be used to mitigate a thermal overload that is less than the thermal rating of a system element by tripping or by generator run-back. This may be an appropriate application for an overload that results from a single (or multiple) contingency outage event. The OMS may be manual (with a response time not greater than 30 minutes) or automated (with a faster response time). Typically, response time for an OMS application is measured in tenths of seconds to minutes. Generally, an OMS can be thought of as a scheme that can be backed up by relay operation or operator intervention if necessary. An OMS will not be considered as acceptable mitigation for system element overload if its failure to operate properly could lead to widespread outages on the Bulk Electric System.

- A RAS may be used for certain single and multiple contingency outage events that result in unacceptable electric system reliability performance that is not related to minor thermal overloading and that requires a more immediate response (e.g., unacceptable transient stability performance). A RAS must be an automated response to the outage. Typically, response time for a RAS application is measured in cycles or at most a few seconds. While the ranges of expected response times may overlap, there is a distinctly different character to a RAS. It may be expected to meet a higher reliability standard, depending on the application. There is no expectation that a transmission system operator could intervene if the RAS were to fail to operate. Any RAS application must meet WECC system planning criteria. The TP will submit any RAS application that may be proposed to the WECC RASRS for their approval if the RAS failure could lead to widespread outages on the Bulk Electric System of the Western Interconnection. If a RAS does not receive the approval of the RASRS, the TP will not use it.

Voltage Ride Through

The TP will follow FERC and WECC voltage ride through criteria as appropriate. Under certain circumstances, the TP may require the generation to trip offline to maintain system reliability instead of riding through the event.

NERC Reliability Standard Requirements and WECC Reliability Criteria

The NERC Reliability Standards and the WECC Reliability Criteria are used to evaluate the system performance under steady state and transient stability and the recovery performance of the BHCE transmission system.