Transmission System Studies Guide

November 7, 2014

Transmission System Studies Guide

Approved by: Manager (Growth Capital Planning)

1. Introduction

Transmission planning is an ongoing process of assessing the electric system and its ability to deliver electricity reliably, efficiently to customers and recommending system reinforcements to meet forecast load demand. Transmission planning decisions are based on an integrated planning approach that considers key inputs: forecast load growth, plans for new generating capacity, sustainment needs related to asset maintenance, First Nations and the public. The transmission planning effort includes the technical aspects of transmission studies: scoping study requirements, preparing study data, clarifying study assumptions, undertaking technical analysis, documenting study results. Study results are compared to required reliability standards for system performance to identify whether system reinforcements are required, and if so, assess the effectiveness of reinforcement alternatives. BC Hydro's reliability standards are based on industry standards established by the North American Reliability Corporation (NERC), supplemented by Western Electricity Coordinating Council (WECC) Regional Criteria.

This Studies Guide is intended to serve as an information document that describes the study process and the technical and economic aspects involved in transmission planning at BC Hydro. It is structured to take the reader through the steps of data preparation, technical studies, identification of reinforcement alternatives, and recommendation of projects. Certain aspects of the study process – data preparation, assessment documentation, technical studies, and reliability standards – are subject to review by WECC for compliance with the BCUC adopted NERC Mandatory Reliability Standards. NERC Mandatory Reliability Standards go beyond simply specifying the reliability standards for performance of power systems. Related to system transmission planning study, MRS addresses aspects of data preparation, facility ratings, system operating limits, transfer capabilities for open access service, and long term planning assessments, including documentation and communications.

This document does not address aspects associated with transmission system planning that are process related, process specific to BC Hydro, and new facility design, such as:

- Transmission Planning (Attachment K) Process and procedures for coordination of planning, (internal and external), First Nations consultation, Public consultation, the preparation of Capital Plans, and project approvals. This is addressed by the OATT Attachment K, BC Hydro's regulatory filings, and other internal documents.
- Detailed study assumptions.
- Facility and equipment standards, such as transmission line and substation equipment overload capability, and system specific issues such as sub-synchronous resonance, electromagnetic transients, and insulation coordination.
- Special technical evaluation procedures, such as probabilistic planning.
- Environmental considerations.

Section 2 discusses the sources of study data, which includes load forecasts and equipment and facility ratings data, and the preparation of system model base cases.

Section 3 discusses reliability standards for system performance.
Section 4 describes the technical studies undertaken by BC Hydro using the planning study data and reliability standards.
Sections 5 discusses aspects of identifying system reinforcements and **Section 6** discusses the benefits of these reinforcements. **Section 7** describes the economic methods for evaluating system reinforcement alternatives.
Section 8 describes how a project recommendation is made from the various alternatives.
Section 9 discusses the final steps of system transmission planning, project application and operating studies that follow project approval.
Section 10 provides a brief discussion on Mandatory Reliability Standards and BC Hydro's compliance requirements.
A Glossary of Terms is included in **Section 11**.

Four appendices include detailed reference documents for various aspects of system planning studies.

Contents

2 Planning Study Data

The BC Hydro power system is a complex network of transmission lines at various voltage levels, substation interconnections, transformers, generators and customer loads. BC Hydro is also interconnected to other utilities in B.C., Alberta, and the U.S. To support an efficient planning study process, study data that models the BC Hydro system and interconnected systems is prepared by BC Hydro, and stored electronically as base cases for planning studies. Study data includes load, facilities and equipment, system parameters, and information provided to the planning process by customers and stakeholders. Base cases are prepared for the current system and future years. This section of this Transmission System Studies Guide discusses study data that is included in system planning base cases for power flow and stability studies of the interconnected system.

2.1 Load forecasts

Two load forecasts are developed for system planning studies, a non-coincident Station peak load forecast, and a coincident system peak forecast.

2.1.1 Non-coincident Station Peak Load Forecasts

These ten year load forecasts are developed for each distribution substation and are based on the action metered load in the substations as well as projected development of the load area. This forecast provides the four peak MVA loads –high and mid with and without incremental DSM impact[1] expected at each of the BC Hydro substations. Actual historic metered loads are normalized (adjusted) to reflect abnormal historic conditions, such as recent colder than normal winters. Normally these are peak winter loads, but some substations are summer peaking. In areas with more than one distribution substation, these forecasts will reflect load transfers from one substation to another. For example, if the load at one substation is nearing its supply capacity and another nearby substation has spare capacity, and distribution upgrades can be made to transfer loads to the substation with spare capacity.

High forecasts with DSM for distribution substations are used for planning transformer and other substation upgrades and for transmission planning.

2.1.2 Coincident System Peak Load Forecast

[1] There is an approximate to a 90% chance that the peak demand will not exceed the forecast peak demand value. It includes rate uncertainty, weather elasticity, GDP and residual uncertainty. In also includes DSM impact (low DSM).

Not all substations peak at the same time, or on the same day of any given year. Even among winter peaking and summer peaking substations, there is some diversity in the timing of peak non-coincident loads. Normalized coincident peak load forecasts, provided for each of the 20 years in the planning horizon, are based on historic peak generation and forecast economic development in the province and its dependence on electricity. Coincident load forecasts are also used for generation resource planning. Transmission system planning base cases incorporate coincident load forecasts.

2.2 Major Transmission Facility Ratings

Detailed procedures for the major transmission facility rating facilities are documented in BC Hydro's Bulk Electric System Facility Rating Methodology. Major Facilities addressed by this Methodology include:

1. Transmission Lines
2. Transmission Cables
3. Transformers
4. Shunt Reactors
5. Circuit Breakers
6. Shunt Capacitors
7. Series Capacitors
8. SVC (Static Var Compensators)
9. STATCOM
10. DC Terminal

Most facilities have been rated according to BC Hydro's Bulk Electric System Facility Rating Methodology. However, some facilities that have been in service for a significant length of time may not be accurately rated according to this methodology. For example, a transmission line built some years ago may have had a nominal rating because the load has been well below the lines supply capability. However, as the line loading approaches the line's nominal rating, BC Hydro will initiate a review of the rating.

2.3 Generator Capacity and Dispatching patterns

2.3.1 Generator Ratings

For each generating resource, BC Hydro specifies three plant capacities that are used to define generation dispatch assumptions in transmission system studies:

Maximum Power Output (MPO): This is the maximum output that the generating unit or plant is capable of producing. The MPO value is the highest output that the plant would be able to produce under the most favourable conditions (e.g. maximum head for hydro plants and coldest weather for gas turbines) considering the season.

Dependable Generating Capacity (DGC): The generator output that can be reliably supplied coincident with the system peak load, taking into account the physical state and availability of the equipment, and water or fuel constraints.

System Capacity (SC): The SC of a wind farm or run-of river (ROR) hydro plant is equal to it ELCC value. The SC of a large hydro plant and any other non-intermittent resource is equal to its DGC value.

Effective Load-Carrying capability (ELCC): This is the incremental amount of load demand that an intermittent plant can supply when it is added to the system based on maintaining the one day in ten years Loss of Load Expectation (LOLE) generating capacity adequacy criterion. The ELCC of an intermittent resource like a wind farm is equivalent to the capacity of a conventional generating plant (e.g. large reservoir hydro plant) in terms of load supply reliability. The ELCC of an intermittent resource is the amount by which the load duration curve in an LOLE study can be shifted up when the intermittent resource is added to the resource stack while keeping the LOLE index value the same as the addition of the intermittent resource.

2.4 Base Cases

Base cases are prepared according to established procedures, documented in BC Hydro Data Management Procedures. This document outlines the responsibilities for base case preparation. Base cases will include facility representation data described above. Base cases will also include load forecast data and external system representation data.

Planners may have to modify base cases for their specific study uses. For example, various generation dispatch scenarios may need to be assessed to determine the system limitations. All modifications to the base case are documented in the study report.

2.4.1 External System Data

Western Electricity Coordinating Council (WECC) coordinates the preparation of member system base cases representing the whole of the Western Interconnection. WECC prepares specifications for conditions to be represented in each base case and each WECC member submits data appropriate for those conditions. The intent of each base case is to stress some portion of the western interconnection for certain typical conditions in a current or future year. An example of such a base case would be summer peak loads in California with peak hydro generation in British Columbia, Washington and Oregon. This base case is designed to stress the transmission system between Washington/Oregon and California.

The need for accurate representation of external systems in BC Hydro system transmission studies will depend on the nature of the studies. At one bookend, accuracy of external system representation is not critical for BC Hydro sub- transmission studies. At the other bookend, bulk transmission studies involving export on existing interconnections, new interconnections, transient stability studies, or extreme multiple contingency events, may require more accurate representation of external systems. BC Hydro base cases include a representation of external systems, normally an equivalent representation based on a current or recent past year base case. BC Hydro will become familiar with the needs for external system representation through study experience and shall ensure that external systems are adequately represented in studies. In cases involving studies of interconnections with other systems it may be necessary to replace the equivalent representation of external systems provided in the BC Hydro base case with a detailed representation. This will be coordinated by the appropriate BC Hydro System Planners and the external system planners.

2.4.2 Reference Documents

The following reference documents are included in the Appendices:
Appendix 1 – Bulk Electric System Facility Rating Methodology, 30 August 2013
Appendix 2 – (BCTC) SPPA Data Management Procedures, Report No. SPA2008-53, 23 April 2008

3 System Planning Performance Requirements

BC Hydro Transmission Planners study the reliability of the power system by simulating normal and outage conditions and comparing the results of these simulations to system performance requirements. BC Hydro's system performance requirements are documented in BC Hydro System Operating Limits (SOL) Methodology. This document summarizes the NERC and WECC Reliability Standards and Regional Criteria adopted by BC Hydro as well as BC Hydro's own additional standards. The title of these BC Hydro reliability standards originates from a NERC standard that requires power utilities to document their reliability standards for system performance in a document referred to as a SOL Methodology. BC Hydro's SOL Methodology includes not only reliability standards, but also summarizes various assumptions regarding use of the reliability standards.

NERC Reliability Standards summarize the industry practices followed by the majority of utilities for system reliability across North America. These NERC Standards address both internal system performance and the allowed impact on other external systems. WECC Regional Criteria defines additional external system performance requirements Western Interconnected Utilities must meet. The WECC Regional Criteria has also been adopted by BC Hydro for its internal system performance. In addition to the WECC criteria, BC Hydro has added its own system performance criteria that is specific to the BC Hydro system and addresses how the WECC/NERC standards and criteria will be applied during unplanned conditions. System reliability standards are based on certain fundamental principles. Firm loads must have a high level of reliability and system disturbances must be contained within the affected part of the system and not cascade to other areas. Contingency/Performance requirements for the BC Hydro system are provided in the BC Hydro System Operating Limits Methodology and are reproduced here in Table 1 for conditions of all lines in service and during planned maintenance outages and Table 2 for conditions of forced outages and unplanned load. Some contingencies, such as the loss of an overhead transmission line, will occur more frequently but have shorter outage durations. A transmission line may be returned to service within an hour or be out of service for a few days if a tower is damaged. Other contingencies may occur less frequently but be of longer duration. Power transformers and cable circuits have few outages but, when they fault, can be out of service for weeks or longer. The reliability standards do not distinguish between contingencies based on frequencies of occurrence and durations of the outage. Instead they categorize contingencies by the number of elements out of service following the system disturbance.

3.1 Contingency Categories

The following highlights the major requirements contained in Tables 1 and 2 of the BC Hydro System Operating Limits Methodology. Further details are provided in the BC Hydro System Operating Limits Methodology.

3.1.1 Categories A, B, and C

Required system performance is based on the contingency that occurs on the system and the resulting number of elements out of service. In Table 1, Category B is an N-1 contingency (N-1 stands for normal condition, all lines in service, minus one facility out of service) for which there should be no loss of firm load (except consequential load loss). Category C is an N-2 (normal condition minus two facilities tripping out of service simultaneously), for which the requirement is power transfers, voltages and frequencies within acceptable limits. Category C contingencies are mostly multiple element outages resulting from a failure of a circuit breaker to open following a Category B contingency. Category C also includes adjacent circuit simultaneous contingencies, two circuits on a multiple circuit tower and two adjacent lines on a common right of way. An N-1-1 contingency (normal condition minus one facility out of service, followed by system adjustments, minus another facility out of service) would be addressed by Table 2, unplanned single contingency system condition, after system adjustment, Category B. The type of fault (e.g. SLG, 3-phase) is specified for stability studies, because some faults are more severe than others for stability.

3.1.2 Category D

This category includes extreme low probability events. The system is not designed to fully cover for every multiple contingency that may occur on the system. Category D requires an evaluation of risks and consequences of extreme contingencies. Category D contingencies are not normally considered in system studies related to reinforcement projects, but instead are addressed in separate studies addressing safety nets for extreme events. Undervoltage load shedding is an example of a safety net that would be used to address extreme events. Rather than responding to specific contingencies, undervoltage load shedding responds to relays sensing that the system voltage is lower than would be expected due to Category B and C contingencies. Controlled system islanding is another example of a safety net. These safety nets are reserved as a response to extreme unplanned events and are not used in response to Category B and C contingencies.

3.2 System Limits and Allowed Impacts

3.2.1 Facility Rating Limits

Facility loadings must be within emergency rating limits before operator action and within continuous operation limits after operator action. Both limits must be met.

3.2.2 Transient Voltage Dip and Minimum Transient Frequency

These are nominal limits based on general protection system settings including a margin, provided in the WECC Regional Criteria. BC Hydro attempts to meet these limits if at all possible. If studies indicate these limits will not be met and there are no practical corrective actions, BC Hydro may consider investigating whether the margin can be reduced without loss of firm load or risk of cascading.

3.2.3 Post Contingency Steady State Voltage

These limits must be adhered to under all conditions except as noted in tables 1 and 2 of the SOL Methodology.

3.2.4 Voltage Stability Margin

These limits are based on a WECC Regional Criteria and must be met.

3.2.5 System Stable

The system must be stable for Category A, B, and C.

3.2.6 Loss of Load or Curtailed Firm Transfers

BC Hydro and industry standards permit consequential load loss, which NERC defines as all load which is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault. In other words, it is not permissible to transfer trip a load. Loads served by a single radial line will lose service when the line is tripped. There is no standard regarding the maximum load size that can be lost as a consequential load loss.

3.2.7 Cascading Outages

Cascading outages are not permitted for Category A, B, and C.

These system limits and allowed impacts are included in BC Hydro's SOL Methodology. The SOL Methodology also provides clarifications for studies and how to apply these tables. Some clarifications are worth highlighting.

The WECC transient voltage and frequency specifications are parameters agreed to by WECC members as the allowed impact on other systems. These allowed impacts by others are applicable as long as the member system uses them for its internal system disturbance allowed impacts. Should a member system not adhere to these specifications for its own internal disturbances, it must also permit other member systems to have the same impact on its system for their system disturbances.

Automatic reclosing, a protection system feature which recloses circuit breakers following a fault detection clearing, is used on some transmission lines in an attempt to quickly return the line to service following a temporary fault. The reliability standards apply to both temporary and permanent faults. Where automatic reclosing is used, simulations include an assumption of a permanent fault with automatic reclosing occurring onto the permanent fault.

One important consideration of the reliability standards is loss of load following an N-1 contingency. This is usually a case in which a load is served by a single radial line. When the line is removed from service, supply to the load is lost. BC Hydro has many radials lines. When the load reaches the rating of the line and reinforcement is required. The appropriate reinforcement will be determined case by case. Sometimes, the appropriate solution is to upgrade the radial supply capacity and maintain radial supply; other times, upgrading to a redundant supply is desirable.

Performance during planned maintenance outages is addressed by Table 1 of the SOL Methodology. The premise is that planned maintenance outages will be done at off peak periods when full transmission capacity is not needed. However, for certain configurations such as radial transmission lines, it might not be possible to find an off peak period for maintenance outages while still adhering rigidly to this standard without constructing additional facilities. In these situations, BC Hydro will document its findings and seek approval of a recommended course of action.

The following reference document, outlining the BCH SOL Methodology is included in the appendices:

Appendix 3 – BC Hydro System Operating Limits Methodology for planning Horizon, Report No. SPA 2008-02.Rev.3

Table 1 Contingency/Performance Requirements - All Lines in Service or Planned Maintenance Outages

Pre-Existing Conditions	Category	Contingencies		System Limits or Allowed Impacts							
		Initiating Event(s) and Contingency Element(s)	Elements Forced Out of Service	Facility Rating Limits	Transient Voltage Dip	Minimum Transient Frequency	Post Contingency Steady State Voltage	Voltage Stability Margin	System Stable	Loss of Firm Load or Curtailed Firm Transfers	Cascading Outages
Planned System Conditions	A - No Contingencies	No Contingencies - All Facilities in Service , Planned Outages	None	Continuous			Normal Operating Range	105% of the SOL	Yes	No	No
Planned System Conditions	B – Event resulting in the loss of a single element.	Single Line Ground (SLG), 3-Phase (3Ø) Fault with Normal Clearing, or loss of element without a fault (including failure to operate and inadvertent operation of related protection): 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt device (e.g. reactor, capacitor, SVC, synchronous condenser) Single Pole Block, Normal Clearing : 5. Single Pole (dc) Line	Single	Before Operator Action – Emergency Limits After Operator Action – Continuous Limits	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6** Hz for 6 cycles or more at a load bus.	Non-ESA busses: Deviation not to exceed **5%** at any bus. ESA customer POD: per ESA.	Non-ESA busses: 105% of the SOL ESA customers: 100% of forecast load.	Yes	No loss of firm load or firm transfers, except consequential loss. Generator tripping permitted only for special circumstances and WECC's MORC must be met.	No
Planned System Conditions	C – Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing : 1. Bus Section 2. Breaker (failure or internal fault) – internal system impacts Bipolar Block, with Normal Clearing : 3. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing, excluding short distance situations: 4. Any two circuits of a multiple circuit towerline 5. Two adjacent circuits SLG Fault, with stuck breaker or primary protection system failure: 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section - internal system impacts Failure to operate or inadvertent operation of protection: 10. Protection related to any Category C event.	Multiple	Before Operator Action – Emergency After Operator Action - Continuous	Not to exceed **30%** at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0** Hz for 6 cycles or more at a load bus. Internal exception for conditions resulting in islanding: Minimum 57.9 Hz	Non-ESA busses: Deviation not to exceed **10%** at any bus. ESA customer POD: not considered.	Non-ESA busses: 102.5% of the SOL ESA customer POD: not considered.	Yes	Planned/Controlled	No
		Other common mode failures and external impacts 11. Common mode loss of two generating units connected to the same switchyard not addressed above,	Multiple						Yes	Controlled	No
Planned System Conditions	Category D – Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of-way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. • May involve substantial loss of customer demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may or may not achieve a new, stable operating point. Evaluation of these events may require joint studies with neighboring systems.								

Table 2 - Contingency/Performance Requirements - Forced Outages and Unplanned Load

Pre-Existing Conditions	Category	Contingencies		System Limits or Allowed Impacts							
		Initiating Event(s) and Contingency Element(s)	Additional Elements Forced Out of Service	Facility Rating Limits	Transient Voltage Dip	Minimum Transient Frequency	Post Contingency Steady State Voltage	Voltage Stability Margin	System Stable	Loss of Firm Load or Curtailed Firm Transfers	Cascading Outages
Unplanned system conditions, after system adjustment	A - No Additional Contingencies	No Additional Contingencies	None	Continuous			Non-ESA busses: Deviation not to exceed **5%** at any bus. ESA customer POD: per ESA.	Non-ESA busses: 105% of the SOL ESA customers: 100% of forecast load.	Yes	Pre-existing single contingency - No loss of firm load or firm transfers, except consequential loss. Pre-existing multiple contingency – Controlled.	No
Unplanned single contingency system conditions, after system adjustment	B – Event resulting in the loss of an additional single element.	Single Line Ground (SLG), 3-Phase (3Ø) Fault with Normal Clearing, or loss of element without a fault (including failure to operate and inadvertent operation of related protection): 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt device (e.g. reactor, capacitor, SVC, synchronous condenser) Single Pole Block, Normal Clearing: 5. Single Pole (dc) Line	Single	Before Additional Operator Action – Emergency Limits After Additional Operator Action - Continuous Limits	Not to exceed **30%** at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0** Hz for 6 cycles or more at a load bus. Internal exception for conditions resulting in islanding: Minimum 57.9 Hz	Non-ESA busses: Deviation not to exceed **10%** at any bus. ESA customer POD: not considered.	Non-ESA busses: 102.5% of the SOL ESA customer POD: not considered.	Yes	Controlled	No
Unplanned multiple contingency system conditions, after system adjustment	B – Event resulting in the loss of an additional single element.	Single Line Ground (SLG), 3-Phase (3Ø) Fault with Normal Clearing, or loss of element without a fault (including failure to operate and inadvertent operation of related protection): 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt device (e.g. reactor, capacitor, SVC, synchronous condenser) Single Pole Block, Normal Clearing: 5. Single Pole (dc) Line	Single	Before Additional Operator Action – Emergency Limits After Additional Operator Action – Continuous Limits					Yes	Controlled	No
Unplanned system conditions, after system adjustment	C – Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing : 1. Bus Section 2. Breaker (failure or internal fault) Bipolar Block, with Normal Clearing: 3. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing: 4. Any two circuits of a multiple circuit towerline 5. Two adjacent circuits SLG Fault, with stuck breaker or primary protection system failure: 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section Failure to operate or inadvertent operation of protection: 10. Protection related to any Category C event	Multiple	Before Additional Operator Action – Emergency Limits After Additional Operator Action – Continuous Limits					Yes	Controlled	No
		Other common mode failure Common mode loss of two generating units connected to the same switchyard not addressed above,	Multiple						Yes	Controlled	No

4 Technical Studies

The purpose of the technical studies is to simulate stressed conditions on the system to determine if the system will perform within the system limits and allowed impacts for possible pre-contingency and contingency conditions. Technical studies are conducted by running computer model simulations of system normal and contingency conditions on the power system. The computer model simulations use the data and base cases described above in Section 2. The Contingency/Performance Requirements tables of Section 3 list the contingency conditions studied and required system performance.

Studies are set up by first tuning a steady state "normal condition" (pre-contingency) base case representation of the system and the scenario to be studied. In a real system, rarely are all facilities in service. In technical studies, "normal condition" refers to all facilities (eg transmission lines) are in-service Contingency cases are "what if" tests of the system – what if a fault occurs at this point on the system and the faulted element is removed from service – and the system response is evaluated.

Post fault steady state power flow outage conditions with Category B contingencies could trigger the need for major facility reinforcements. During Category B conditions, many facilities remaining in service could have higher flows than before the outage and most voltages could be lower than before the outage. Transient stability immediately following a fault can also be a limiting condition for longer, loosely coupled systems. After fault clearing, a stable system will settle to a new stable operating point. However, a system that is too highly stressed could cause generators to swing out of synchronism and may cause cascading outages. Even if a system is initially stable and damped, over a longer time period a heavily loaded system may collapse due to voltage instability. Therefore, worst case conditions need to be studied that includes the effects of automatic controls such as transformer tap changers and generation controls.

For Category C contingencies that are related with substation bus and circuit breaker configurations, planning first evaluates system upgrade solutions to mitigate the impacts. Category C contingencies not addressed via system upgrades can be addressed with Special protection Scheme.

4.1 Preparation for Technical Studies

Preparation for technical studies begins by preparing a study scope. The study scope should be commensurate with the stage of planning and addresses the following:

- Identify system modeling and data requirements. List any assumptions that may impact the study results. Technical studies often involve a multitude of possible initial conditions and working with uncertain or imperfect data. If necessary, identify possible sensitivity studies required as a result of these study assumptions.

- Identify the problem or issue to be investigated (e.g. load growth increasing the loading on the system, new generation interconnection, replacement of aging facility, new substation)
- Review and identify possible constraints in the system and contingencies that might stress these constraints. Prepare contingency lists for power flow studies and, if required, transient stability studies.
- Identify system reinforcement alternatives and other solutions to address the system limitations and impacts identified in the study. Section 5 below provides discussion of identification of solutions.

4.2 Study Simulations

BC Hydro uses a commercial computer simulation program package provided by Power Technology Industries (PTI) for power flow and stability analysis. This is one of two computer programs supported[2] by WECC, the other being GE. WECC also conducts simulations of actual system events for comparison with disturbance monitor records, which further verify the accuracy of these simulation programs. BC Hydro also uses Power Tech PSAT, VSAT TSAT tools for power flow studies. Other specialized simulation programs are also used by BC Hydro such as EMTP for detailed transient study analysis, and MECORE for system reliability analysis.

When running contingency cases, BC Hydro will ensure that simulations reflect substation equipment outages that can occur due to substation arrangements. Base cases may not reflect all the details of substation arrangements. For example, a transmission line outage may result in an outage of a transformer or line end reactor within the circuit breakers zone for a transmission line, but these may be modeled as separate branches in the base case.

Simulation study results shall be documented in either tables or in power flow diagrams, or both, as appropriate for the study.

4.3 Study Report

BC Hydro will prepare a study report documenting the study scope, study assumptions, simulation results, conclusions and recommendations of the study. The report will discuss salient study results, pointing out limiting conditions.

Study reports for a shorter term planning horizon will focus on those recommendations that can be implemented in the short term, such as changes in operating procedures, remedial action

[2] Support by WECC means that WECC provides its base case data in a format appropriate for use in one of the two supported programs.

schemes, and changes in amounts of generator shedding. Longer term planning horizon reports will address system upgrades, such as new facilities, system reconfigurations, and changes in substation arrangements (e.g. additional circuit breakers, line termination rearrangements). Section 5 below, Identification of Solutions, discusses alternatives for addressing system constraints.

5 Identification of Solutions to System Constraints

When system transmission studies identify that the system response to a disturbance will not meet reliability standards, BC Hydro will identify a solution or number of potential solutions and undertake studies to assess the performance of each solution. Short term solutions are often low cost and can be often implemented operationally. Ideally, all system reliability standards will be adhered to and these short term solutions are simply low cost stop gap measures to delay the implementation of higher cost longer term solutions. However, a short term solution may also be necessary if a load or generator has an aggressive in-service date that system reinforcement cannot be implemented to meet the requested in-service date. Long term solutions typically require higher capital investments that may require up to a decade to implement, but will also provide for meeting all reliability standards. “Non-wires” solutions include actions that can be taken by customers to mitigate the issue that is causing system limitations and impacts.

5.1 Short Term Solutions

For the transmission system, a common short term solution is to implement or increase the amount of generator shedding or load shedding. For Category C contingencies, this is also an acceptable long term solution. Also, this remedial action is also acceptable for non-firm load and new unplanned firm load (load that is added to the system within a time horizon for which new facilities cannot be constructed). If used for unplanned firm load, technical studies must commence to identify long term solutions.

During the development of a short term solution, the rating of the critical facilities will be reviewed. For example, if the limitation is a thermal rating of a transmission line that has not been reviewed recently, a rating review should be initiated. It may be possible to alleviate the system limitation or implement an operating procedure to operate the facility at more discrete levels without significant loss of life. On the other hand, possible outcome of such a review is that the actual rating might be lower than recorded, but this is also an important outcome of the review since the facility may be unknowingly operated beyond its rating.

System reconfiguration may also provide a short term solution for unplanned firm load. This might involve opening network connections to radially supplying loads on single lines.

5.2 Long Term Solutions

Long term solutions to address Category B contingencies generally focus on system reinforcements such as: new transmission lines, new substations, substation facility additions, voltage support equipment, and transmission line upgrades. New facilities have long lead times, with some transmission lines requiring more than 10 years from inception to commissioning.

Thermal constraints typically require a new transmission line or the upgrading of the existing lines. If the constraint is low voltages, then voltage support facilities may be all that is needed. The type of equipment used will be determined by the system needs and performance requirement for various operating scenarios. Generator reactive capability can be used for normal conditions subject to generators not reaching reactive power output limits during contingencies. Category C contingency limitations are often addressed by substation configuration changes. Substation layouts can be configured such that no two sources or load lines are connected on adjacent line termination positions, separated by a single circuit breaker. In some large substations with many critical transmission lines terminated, breaker and a half and double breaker bus arrangements can avoid loss of multiple lines due to breaker failure. Even when it might be possible lose a second line without violating thermal limits, keeping a 500 kV line in-service during outages of other lines can be an effective means of providing voltage support.

Transmission and substation planning are coordinated with distribution planning. Distribution feeders have more outages than transmission lines and incur proportionally higher losses. Very long distribution feeders have power quality issues. As new load areas grow, new substations resulting in the extensions of the regional transmission system should be considered to shorten the distances power is transmitted on distribution feeders.

5.3 Non-wires Solutions

Non-wires solutions include new generation, generation re-dispatch, load management, and other options that typically involve customers modifying their demand or use of the transmission network. Non-wires solutions may provide a long term solution, or possibly just a short term bridging solution until long term system reinforcement can be implemented.

Demand side management programs are often designed to reduce energy consumption. Energy consumption reduction programs may or may not also reduce peak demands.

5.4 Documentation of Short Term, Long Term, and Non-Wire Solutions

Each project, including the alternatives, to address a system limitation requires a cost estimate and a timeline for implementation. Expected accuracy of the cost estimate should be commensurate with the stage of planning (Study, Definition, and Implementation), taking into account the cost of refining the accuracy of cost estimates. Feasibility level planning evaluations require lower expected accuracy than project proceeding to implementation.   Required accuracy for each stage of planning is defined in BC Hydro’s Estimating Practice document contained in the Practices Reference Tool.

6 Secondary Benefits, Impacts, and Considerations

6.1 General Considerations

BC Hydro applies an Integrated Planning approach to consider needs, benefits, and impacts, from both a growth and sustainment perspective to develop and evaluate alternatives. A significant secondary benefit for some system reinforcements compared to others is a reduction in system losses. This can occur when a new transmission line is added to a network instead of using voltage support. It can also occur when a load is served by a closer or higher voltage transmission source, such as a new substation reducing the length of distribution feeders to customers. Normally, a long term losses savings would be valued at the long term value of electricity, short term at the current market value. Losses reduction estimating methods are described in more detail below.

A new high capacity facility may allow an older facility to be retired, avoiding typically higher operation, maintenance, and sustainment costs of the older facility. BC Hydro would not only review opportunities to retire entire facilities (e.g. transmission line, substation), but also review opportunities to replace individual components within a facility that are end-of-life (e.g. circuit breakers, transformers). Other benefits may also be found, such as, improved system flexibility during off peak periods, and overall higher system reliability. Many of these benefits can be quantified and included in the planning evaluation.

6.2 Transmission Losses Reduction

Reductions in transmission losses can be a very significant benefit of new additional transmission lines, compared to other system reinforcement alternatives such as additional voltage support, series compensation, and increasing transmission line ground clearances. Transmission line re-conductoring can also reduce losses.

A new transmission line reduces overall transmission grid losses by off-loading other transmission lines. Losses are a function of the square of the current , so two lines in parallel will each have one quarter of the losses of a single line, and total losses will be one half of the losses of one line. During the transmission line design phase, conductors are optimized to reduce losses compared to the additional costs of a larger conductor.

Two alternative methodologies are used to estimate losses reductions. BC Hydro's PLOSS program uses power flow calculations at various load levels and generation dispatches to estimate losses for various operating conditions throughout the year. These results are summed to obtain a total annual energy losses estimate. PLOSS is described in further detail in the program user manual.

A second methodology for estimating losses uses a power flow calculation of losses at peak load and a load loss factor to estimate total annual energy losses. The load loss factor can be estimated using a traditional formula or using the PLOSS program.

6.3 Capacity Considerations

Some system reinforcement alternatives may have a higher capacity than others. Higher capacity reinforcements serve more load growth for a longer time, before the next reinforcement is required. Planning evaluations should identify the residual value of a higher capacity reinforcement and reflect this in the comparison of alternatives. If one of the alternatives provides a relatively low capacity addition that may require further reinforcement within the 10 year planning horizon, the capacity difference can be evaluated by assuming a further reinforcement is required and comparing scenarios. Also, various economic comparisons techniques can be employed to equalize projects and scenarios. This is discussed in Section 7.

6.4 Environmental Considerations

Some alternatives may have a lower environmental impact than others. BC Hydro projects must adhere to all environmental requirements. Efforts to address environmental concerns beyond established standards can be very subjective. Significant environmental issues would normally be addressed under the auspices of a project manager. Environmental issues may be mitigated by redesigning or rerouting the facility, which affects the cost of the facility, and thereby potentially the economics of this planning alternative relative to other alternatives.

7 Economics

System planning economics usually involves identifying the lowest cost reinforcement alternative among the technically acceptable alternative solutions. The costs of alternative projects, including benefits and impacts, are evaluated using a Net Present Value (NPV) methodology. This is an established financial evaluation technique, using discount rates, which converts future costs and benefits to an equivalent value in the current time period. The alternative with the lowest NPV cost would normally be identified as leading. Economic comparisons of project alternatives should include, in addition to project capital costs, new project operating and maintenance costs, taxes, and any other costs that will be incurred as result of proceeding with the project. Quantifiable benefits such as lower transmission system losses are also included in the comparison. Comparisons should also recognize that different types of facilities may have different expected lifetimes until replacement is needed. For example, steel tower lines have a longer lifetime than wood pole lines.

Net present value comparisons are typically done using “real” dollars (current year dollars with no inflation added for future years) and real discount rates (interest rates net of allowance for inflation) to simplify calculations. If inflation is included in the calculations, this is known as nominal dollars and nominal discount rates are used.

If two alternatives have similar NPV costs, a sensitivity analysis can be completed to evaluate how the NPV costs are impacted by changes in key inputs. For example, if one alternative has a high capital cost but will provide future benefits over a long period of time, resulting in an NPV cost comparable to another lower capital cost alternative, a sensitivity analysis would evaluate the impact on the NPV cost of capital cost variations and the risk of future benefits actually materializing. Sensitivity analysis is also sometimes done using a higher discount rate in the NPV calculation to determine the sensitivity of the economic assumptions to the NPV costs of the alternatives.

8 Project Recommendations

At the conclusion of a study, BC Hydro will make recommendations on system reinforcements. Some planning recommendations may require only technical study results to support the recommendation while others may require consideration of multidisciplinary aspects such as environmental, safety, and stakeholder impacts. Preliminary system planning studies will normally focus on the results of technical studies, assessing only the technical advantages of alternative reinforcements. At this stage, decision makers want to know which projects are the best solutions from a system benefits point of view. Other aspects of the project can be brought into the decision making process as the project progresses, possibly leading to consideration of an alternative project. Also, simple projects that are next stage developments of an earlier development plan may also require only technical studies to support a decision to proceed.

If planning studies progress to projects, then the scope of work will be much broader that involves engineering, environmental, and social aspects. A project manager will often take the lead on these projects and the system planning studies are one input to the project recommendation.

As planning project evaluations become more complex and more trade-offs become apparent between inter-disciplinary issues, higher levels of management involvement will be required to support decision making for the project. Greater complexity of issues can also add significantly to project lead times. Therefore, although preliminary project recommendations may focus on technical system studies, timelines at the preliminary stages should consider the time it may take to resolve complex project issues.

9 System Application and Operating Studies

A system application and operating studies are the final two steps in the planning process. These steps communicate technical and operational information to the designer and other technical disciplines such as station and protection planners, operators, etc.

9.1 System Application

A system application is a summary of the technical requirements for the reinforcement project. It may comprise some or all of the following, many of which would be determined through coordination with the designers engaged in the project:

- From and to buses
- Voltage level
- Transmission line configuration
- Insulation Coordination
- Overhead line type or cable parameters
- Line rating and conductor
- Series capacitor station location and ratings
- Related station equipment, with ratings
- Protection requirements
- Metering and location, if applicable

The purpose of the system application is to communicate the technical specifications identified by the BC Hydro System Planner to the project designers that are required to obtain the system performance determined by the technical studies. The application should list all features of the project that are relevant to system performance, even if not determined in the technical studies. For example, whether a transmission line is wood pole, steel tower, or aesthetic pole may be a design aspect, but the resulting conductor configuration is relevant because it determines the impedance of the line.

9.2 Operating Studies

Operating studies may be performed by the BC Hydro System Planner responsible for the planning of the project or by an operations planner. Operating studies results would be incorporated in operating orders for the control centres. They would address the following:

- Generator dropping associated with the project
- Load shedding associated with the project
- Transformer tap /shunt capacitor bank settings

- Synchronous check relay settings
- Special operating considerations

Operating studies related to a new project coming into service are often undertaken as part of a regular recurring update to operating studies for a portion of the system.

10 NERC Mandatory Reliability Standards

BC Hydro system planning complies with NERC Mandatory Reliability Standards which have been adopted by the BC Utilities Commission. NERC Mandatory Reliability Standards address not only system reliability standards, but also a broad range of planning activities such as data preparation, documentation and communications of study results. BC Hydro is required to document evidence of compliance with these standards. NERC Mandatory Reliability Standards also address a broad range of operating procedures and maintenance practices, including documentation, records retention, personnel training, etc., which apply to other areas of BC Hydro, not discussed in this studies Guide.

One NERC Standard addressing requirements to develop system plans, applicable to system planning is NERC Standard TPL-001-2, Transmission System Planning Performance Requirements. This standard describes the system planning performance requirements and also requires BC Hydro to undertake annual planning assessments and studies, plan the system to meet planning performance requirements, identify Corrective Action Plans, and document all responses to this standard.

The system planning performance requirements is based on BC Hydro's System Operating Limits Methodology, which references TPL-001-2 for voltage limits and deviation.TPL-001-2 is included in Appendix 4 - NERC Standard TPL-001-2 Transmission System Planning Performance Requirements.

11 Glossary of Terms

Following is a glossary of terms used in this Studies Guide. Where available, NERC definitions from the NERC Glossary of Terms have been included. Additional terms have been added for clarity. Note that some terms included below are used by NERC but are not included in the NERC Glossary of Terms.

Cascading (NERC definition) - The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Contingency (NERC definition) - The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

Consequential Load Loss (NERC definition) - All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Continuous Rating – Refer to Normal Rating (NERC standards refer to Continuous Ratings, but NERC does not include this in its Glossary of Terms. NERC's Normal Rating is assumed to mean Continuous Rating.)

Emergency Rating (NERC definition) - The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Evaluation (as used in this Studies Guide) – The entire collection of assessments, analyses, studies, economic comparisons, and other considerations that go into making a project recommendation.

Load (NERC definition) - An end-use device or customer that receives power from the electric system.

Long Term Transmission Planning Horizon (NERC definition) - Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

(Mandatory) Reliability Standard – A NERC document, adopted by the NERC Board of Trustees, posted on the NERC web site, which describes the responsibility of a functional entity to address reliability of the Bulk Electric System. Reliability standards encompass procedures, documentation, communications, system performance requirements, training requirements, and other standardization in the electric industry. (Note that NERC does not have a definition of its standards.)

Near Term Transmission Planning Horizon (NERC definition) - The transmission planning period that covers Year One through five.

Non-Consequential Load Loss (NERC definition) - Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Normal Rating (NERC definition) - The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Planning Assessment (NERC definition) - Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

System Performance Requirements – A technical specification that describes the required response of the system following a system disturbance as well as in a steady state condition. System Performance Requirements have in the past also been called reliability standards, reliability criteria, and planning standards. However, as a result of NERC now using the term Mandatory Reliability Standards to refer to more than just technical standards, these earlier terms are no longer applicable and are now a potential source of confusion for referring to the technical specifications.

Special Protection System/ Remedial Action Scheme (NERC definition) - An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

Stability (NERC definition) - The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.

Stability Limit (NERC definition) - The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.

Study (as used in this Studies Guide, based on NERC Standard TPL-001-2) – Computer simulations of power flow (steady state), stability, or other, required to analyze the performance of the system. (NERC uses "study" throughout TPL-001-2 but does not include it in its Glossary of Terms. The preceding definition is implied from the usage in TPL-001-2.)

System Operating Limit (NERC definition) - The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

Appendix 1 - BC Hydro Bulk Electric System Facility Ratings Methodology

80_10_08_00.pdf

Appendix 2 - BC Hydro TSP Data Management Procedures; Report No. SPA2008-53 Revision September 7, 2012

PRCD TD TSP Data
Management Procedur

Appendix 3 - BC Hydro System Operating Limits Methodology for planning Horizon, Report No. SPA2008-02 Rev.3 Revised: 24 June 2014

RPT TD BC Hydro SOL
Methodology Report N

Appendix 4 - NERC Standard TPL-001-2 Transmission System Planning Performance Requirements adopted by NERC Board of Trustees: August 4, 2011

tpl-001-2.pdf