Integrated Resource Plan

BC hydro

Appendix

2D

Technical Assumptions for Integrated Power System Planning

Table of Contents

List of Tables

1 Introduction

This document describes planning guidelines that BC Hydro uses to conduct integrated power system studies[1] such as those associated with developing the Integrated Resource Plan (**IRP**).

This document is an updated version of the document published as Appendix F9 of the BC Hydro 2008 Long-Term Acquisition Plan (**LTAP**) Application and Appendix C of the former BCTC's 2008 Transmission System Capital Plan (**TSCP**) Application.

2 General

The purpose of this document is to describe the definitions, criteria and assumptions used in the full range of power system planning processes and related studies undertaken by BC Hydro from the high level studies associated with development of the IRP to more detailed studies associated with the submission of an application for a Certificate of Public Convenience and Necessity (**CPCN**) for a specific capital project. This document also clarifies the assumptions used in BC Hydro's application of the BCUC-approved NERC Reliability Standards in its planning processes.[2]

There are a number of planning criteria, guidelines, assumptions and definitions that need to be applied consistently across all power system planning studies regardless of whether those studies are required for: supporting an IRP, responding to a Network Integration Transmission Service (**NITS**) application, the development of a transmission or generation capital project, an application for government or BCUC approval of a particular capital project, or compliance with other requirements of BC Hydro's Open Access Transmission Tariff (**OATT**). The level of detail in the study simply increases at each stage of the planning process.

[1] Integrated power system planning generally includes system studies that model the complete interconnected electric system including generators, transmission lines and load substations. These studies can, but generally do not, model the distribution feeders.

[2] Refer to section 9, item 1.

BC Hydro's planning process starts with the development of an IRP wherein BC Hydro identifies new potential resources (both demand-side measures, (**DSM**) and supply-side resources) for serving future electricity requirements over a range of load forecasts and discrete load growth scenarios. In considering alternative portfolios of new generation resources, BC Hydro also needs to consider the costs and other impacts of the associated transmission system reinforcement requirements. Given the significant number of portfolios to be analyzed, the transmission reinforcements identified to meet reliability criteria are chosen from a relatively small set of alternatives that have different capabilities and costs.

The IRP results in the development of a Base Resource Plan (**BRP**) and a set of Contingency Resource Plans (**CRP**s) in accordance with BCUC's Resource Planning Guidelines.[3] Under the OATT, BC Hydro acting as a "Transmission Customer", must request transmission service from BC Hydro acting as the "Transmission Provider."[4] Under the OATT, this is referred to as Network Integration Transmission Service (**NITS**), which is the transmission service BC Hydro uses to serve its domestic customers.[5] The OATT defines the application process and requirements for a NITS agreement.

The BRP and CRPs are submitted to the Transmission Provider as part of a NITS Application and this process triggers two study phases: (1) the System Impact Study (**SIS**) that identifies the transmission reinforcements needed to provide the required service; and (2) the Facilities Study (**FS**) that provides estimated costs and construction schedules for the associated transmission network upgrades identified in the SIS. The NITS studies also include trade-off analyses that compare

3 BCUC Resource Planning Guidelines: http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf.

4 BC Hydro's Grid Operations Division of the T&D Group acts as the Transmission Provider under the OATT.

5 The OATT, section 28.1, defines Network Integration Transmission as "a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to section 31.3 of the Tariff."

generation re-dispatch options with transmission upgrades in accordance with section 32.3 of the OATT. The process culminates in an agreement for NITS.

BC Hydro also undertakes studies in response to specific requests from entities interested in taking electricity service from BC Hydro (i.e., new domestic customers that will add to BC Hydro's NITS load), as well as other potential transmission system users (i.e., Point-to-Point transmission customers and generator interconnection customers).

For large loads that can have system-wide impacts, the scope of studies will be similar to NITS-level studies. To the extent various studies are being undertaken concurrently, BC Hydro must ensure there is an appropriate level of coordination between them. Subsequently more detailed studies related to specific capital projects and associated CPCN applications provide further opportunities to optimize transmission reinforcement plans.

Electricity supply acquisition plans are implemented in accordance with the OATT through a combination of BC Hydro projects (e.g., Mica Unit 5) and private sector acquisitions to fill the gap between net demand and available supply. Private sector acquisitions can result from a series of staged Competitive Electricity Acquisition Processes (**CEAP**s), which is also prescribed in the OATT.

In evaluating the various supply proposals, a high-level assessment of the impact on transmission upgrade requirements associated with each proposal or clusters of projects is identified and the associated costs estimated. BC Hydro obtains approval from the BCUC to execute Electricity Purchase Agreements (**EPA**s).

Once BC Hydro has entered into EPAs with the proponents of the selected generating projects, the transmission upgrades or generation restrictions needed to reliably connect the new plants to the integrated network are determined using the criteria described in this document.

The following sections summarize key planning assumptions associated with:

- Integrated system load forecasts and DSM;
- Generation;
- Transmission;
- Integrating new generation;
- Economic dispatch; and
- Imports and exports.

3 Integrated System Load Forecasts and DSM

BC Hydro develops two types of integrated system load forecasts: (1) An Energy Forecast – a forecast of annual energy consumption for the BC Hydro system; and (2) A Peak Demand Forecast – a forecast of annual peak demand for the BC Hydro system and for each of the four major regions. The peak demand forecast informs future transmission requirements. The energy forecast is not generally used in distribution or transmission planning studies except when estimating losses.

BC Hydro's long-term load forecasters provide the following "Mid" integrated[6] system forecasts to BC Hydro's transmission planners:

(a) A Mid total integrated system coincident peak demand and a High total integrated system peak demand forecast for a minimum of 20 years.

(b) A Mid integrated system coincident total peak forecast for each of the Lower Mainland (**LM**), Vancouver Island (**VI**), Southern Interior (**SI**) and Northern Region (**NR**). The regional coincident peak forecasts exclude transmission losses.

(c) A Mid non-coincident peak forecast for each individual transmission customer station for 20 years or more.

[6] In this document, "integrated" means that loads in Fort Nelson, the Purchase Areas, Zone IB or Zone II. Other loads not currently connected to BC Hydro's transmission grid are not included in the forecast.

Items (a) to (c) above are prepared (i) before incremental DSM savings[7] and before the impact of future rate increases (i.e. rate impacts) and (ii) with the impact of future rate increases and incremental DSM savings. The DSM savings option selected in the IRP process for the BRP and CRPs are used in developing the forecast items (a) to (c) above.

In addition to the forecasts provided to transmission planners, the long-term load forecasters provide guidelines to distribution planners to use in their development of regional ten-year Mid and High distribution substation peak forecasts. The guidelines provide (a) the regional load growth outlook before incremental DSM savings and before rate impacts and (b) the expected DSM savings and the expected impact of future rate increases for each region. The distribution planners use the regional guidelines to develop individual distribution substation non-coincident peak load forecasts.

In response to the BCUC directive in the (BCTC) Vancouver City Central Transmission Project Decision (dated June 2, 2010) regarding the treatment of DSM in planning studies, DSM savings are fully integrated into distribution substation planning practices while ensuring that risks from DSM demand reduction uncertainty are mitigated. As such, the ten-year plans for managing the distribution assets, as prepared by BC Hydro's distribution planners, are based on the ten-year High distribution substation forecast with the lower DSM level.

In addition to the Mid and High load forecasts, BC Hydro develops load scenarios that depict discrete events that could ultimately cause BC Hydro's load to significantly increase.

BC Hydro's load forecasts are incorporated into the assumptions used in a variety of planning activities, including:

[7] DSM savings means load reduction from programs, codes and standards and rate design such as two-tier rates. Rate impacts means the load reductions for future rate increases under the assumption of a flat or single-tier rate structure.

- IRP;
- Bulk transmission system planning;
- Regional transmission planning;
- Stations planning;
- Distribution planning; and
- Load and generation interconnection studies.

How specific load forecasts/scenarios are incorporated into each planning activity is not described in this document, but is included in planning documents related to those particular activities. For example, a transmission system reinforcement impact study for a CPCN application would include forecasts before and with DSM for base case transmission studies and scenarios, if applicable. Planners involved in concurrent planning activities must coordinate their efforts to ensure, where appropriate, assumptions are applied consistently.

4 Generation

4.1 Generating Plant Capacity Definitions

This section briefly explains the generating capacity terminology used in integrated power system planning studies. For any particular plant, the values associated with these terms may vary seasonally. For example, due to seasonal variations in reservoir elevations, G.M. Shrum and Mica have higher maximum power output[8] (**MPO**) ratings and dependable generating capacity (**DGC**) ratings in August than in February.

For each generating resource, BC Hydro specifies three key plant capacities MPO, DGC and System Capacity (**SC**) that are used to define generation dispatch assumptions in transmission planning studies.

[8] The IEEE definition of *"maximum power output (hydraulic turbines): The maximum output which the turbine-generator unit is capable of developing at rated speed with maximum head and maximum gate."*

Maximum Power Output (**MPO**): this is the maximum output that the generating unit or plant is capable of producing for at least one minute. 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**): This is the capacity value used in the Load-Resource Balance tables and graphs. The SC of an intermittent resource like a wind farm or run-of-river (**RoR**) hydro plant is equal to its 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 before the addition of the intermittent resource.

Reliability-Must-Run (**RMR**) Generating Capacity: This is the minimum generating capacity that a generator owner commits to have on line during peak load periods. Committing to providing RMR generating capacity in a load centre would have the effect of deferring the need to reinforce the transmission system supplying that region.

Conditional Reliability-Must-Run (**CRMR**) Generating Capacity: This is the generating capacity that must be produced by local generating resources (i.e., it cannot be simply spinning reserve) depending on some pre-condition like low output levels from intermittent resources (e.g., RoR hydro or wind) in the load region. For example, suppose a load region requires a certain amount of the local load to be served by local generating resources in order to provide adequate reliability to that region because the transmission system serving the region is constrained. Suppose this region contains some peaking units (e.g., pumped storage hydro or simple-cycle gas turbines, **SCGTs**) with sufficient DGC to back up the region's intermittent resources such as wind and RoR hydro plants that have little or no DGC. The peaking units would provide some level of CRMR so that, should the intermittent resources be shut down, the capacity committed as CRMR generating capacity would be sufficient to serve the Non-Firm load under normal system conditions (i.e., N-0) and also sufficient to serve the Firm load should a prolonged single contingency occur on the transmission system serving the region (i.e., N-1 condition).

Presently, the total aggregate RMR+CRMR value for a region is usually the sum of the DGC values of all plants in the region with the exception of the Burrard Thermal Generating Station (**BGS**) that is subject to the requirements of the *Clean Energy Act* (***CEA***) and a B.C. Government directive.

4.2 Generation Capacity Adequacy And Dispatch

Future generating capacity requirements are informed by periodically conducting probabilistic generating capacity adequacy studies that determine the generating capacity reserve required to achieve a LOLE of one day in ten years, a criterion widely used by electric utility resource planners. BC Hydro's current load and generating resource characteristics indicate that a generating capacity reserve margin of 14 per cent is appropriate for planning purposes. This reserve requirement is included in the total generating capacity in the load/resource balance (**LRB**) tables associated with the portfolios studied when developing the BRP and CRPs.

In the operating time frame, BC Hydro controls generation dispatch to ensure the reliability of the integrated system based on existing system conditions. For transmission planning studies, BC Hydro specifies regional generation dispatch requirements for transmission demand analysis. For single- and multiple-contingency studies, BC Hydro specifies which plants could be automatically shed or run back to meet BCUC-approved NERC Reliability Standards and BC Hydro's transmission planning standards. BC Hydro also specifies the regional aggregate generation dispatch ranges for any prolonged single system contingency.

4.3 Generation Adequacy and Transmission Constraints

BC Hydro's generation capacity adequacy determination (section 4.2) assumes no generation capacity resources are located "behind" a constrained transmission path. If there are situations where some generating capacity is behind a constrained transmission path, the aggregate SC[9] associated with the affected plants must be reduced accordingly in the LRB resource stack. For example, if the aggregate MPO and SC values behind a transmission constraint are 4,000 MW and 3,000 MW respectively and the N-1 capability of the transmission path limits the aggregate generating capacity behind the constrained path to 2,800 MW, the SC value that should be used in the LRB resource stack should be no greater than 2,800 MW (i.e., not 3,000 MW). Similarly if the N-0 capability of the transmission path limits the aggregate generating capacity behind the constrained path to 3,600 MW, then the SC used in the LRB for that group of plants must be reduced on a pro rata basis. That is, instead of using 3,000 MW as the aggregate SC for that group of plants in the LRB, an SC value no greater than 2,700 MW should be used (3000*3600/4000=2700) if that is less than the N-1 constraint.

[9] SC is equivalent to ELCC; refer to section 4.1.

5 Transmission

5.1 Firm and Non-Firm Transmission

This section describes the criteria and assumptions associated with both Firm and Non-Firm transmission requirements for serving BC Hydro's domestic load and BC Hydro's external commitments.[10]

In an OATT, the difference between "Firm" and "Non-Firm" transmission primarily defines the order in which electricity transfers are curtailed when the loading on a transmission path needs to be reduced to maintain system security. All transfers using Non-Firm transmission reservations are curtailed before any transfers using Firm transmission reservations would be curtailed. However, for transmission planning purposes, it is necessary to define "Firm" and "Non-Firm" transmission capacity from a system reliability perspective. In its simplest form, this is based on a deterministic planning criteria that primarily considers normal, (N-0, Non-Firm) and single contingency (N-1, Firm) system conditions. In an OATT, a transmission path consisting of a single transmission line can provide "Firm" transmission service, whereas, from a transmission planning reliability perspective a single line would rarely, if ever, provide any "Firm" transmission capacity.

The transmission system that is ultimately planned, built and operated should meet all BCUC-approved NERC Reliability Standards. Those standards define acceptable system performance for a wide range of system conditions and contingencies. They are not restricted to defining acceptable performance for normal system conditions (N-0) and single contingencies (N-1).

[10] BC Hydro's external commitments include the supply to Seattle City Light under the Skagit River Treaty, the supply to FortisBC under the Power Purchase Agreement (**PPA**) and various small border loads such as Point Roberts.

In particular, adherence to the following BCUC-approved NERC Reliability Standards is important to ensure the planned transmission system will be adequate to supply BC Hydro's domestic customers and import/export commitments reliably:

(a) The transmission planning (**TPL**) series of standards;

(b) The Facilities (**FAC**) series of standards;

(c) The Modeling (**MOD**) series of standards; and

(d) The System Protection (**PRC**) standards including those dealing with Remedial Action Schemes (e.g., PRC 015).

Some studies need to consider inter-control area Transmission Reliability Margins (**TRM**s) that are described in BC Hydro's TTC/ATC business practice.[11]

In addition, it is necessary to define a simpler set of criteria to minimize the complex transmission planning studies needed to assess the adequacy and security of the transmission system and reinforcement options.

Therefore, for deterministic integrated system planning studies, "Firm" supply is defined in this appendix as the system load-serving capability provided when any single major element (transmission line, transformer, HVDC pole, generator, etc.) is out-of-service for a prolonged period. "Non-Firm" supply capacity is defined as the load-serving capability with all elements in service. The Non-Firm transfer capability across a transmission cut-plane is the transfer capability with all lines in service. The Firm transfer across a transmission system cut-plane is the transfer capability under the worst-case single contingency condition.

5.2 Worst-Case Normal Conditions In Planning Studies

Most transmission planning studies are deterministic in nature due to the many static and dynamic conditions that would need to be simulated, assigned probabilities and

[11] Refer to BC Hydro's transmission-related TTC/ATC Business Practice which deals with transfer capability: http://transmission.bchydro.com/transmission_scheduling/business_practices/.

then amalgamated to develop probabilistic measures and rules for assessing transmission system adequacy and security. In the planning environment it is typically not practical to conduct the exhaustive studies needed for a probabilistic evaluation although some approximate probability-based measures have been developed and can be useful in some instances like comparing two options that both meet the deterministic reliability criteria.

In light of the above, transmission planning studies are traditionally based on simulating the worst-case initial system conditions (but with all equipment available for service) for the contingency being simulated and the phenomenon being assessed (e.g., thermal limits, electromechanical stability, voltage dips/sags). These deterministic studies are considered to be "benchmark" tests. The power system is rarely, if ever, in a completely normal state (i.e., all equipment available for service), but if the system meets reliability performance standards for normal worst-case initial conditions (i.e., no equipment unavailable for service), then it is expected that under the more common, less-stressed system conditions it should be able to survive more common, less-severe contingencies with some equipment unavailable.

It is important to note that some possible system conditions would be more extreme than "worst case" because they would not occur in the actual operation of the system. Those extreme and abnormal situations are not modeled in planning studies. For example, if a load region served by a constrained transmission connection contains CRMR[12] peaker units (e.g., SCGTs) to provide needed back-up for intermittent resources in the region in order to reliably serve the local load, the CRMR peaker units might only be providing capacity to the system when the output from the intermittent resources in the region is low and the local load is high. If the generating capacity of those peaker units is not needed to meet the generating capacity adequacy requirements for the system as a whole, they should not be modeled as being at their maximum output levels at the same time as the

[12] Refer to section 4.1 for definitions of generating capacity terms including CRMR.

intermittent resources in the region are at their maximum output levels because that would not occur in the normal operation of the system.

However, if some of the CRMR peaker units that provide back-up to local intermittent resources in a load region are also counted on to provide (**SC/ELCC**) generating capacity to serve the aggregate system load, then the capacity of those peaker units should be modeled as (a) contributing to the aggregate MPO of the upstream or source side of any bulk system cut-planes for N-0 studies and (b) contributing to the SC for N-1 studies.

5.3 Transmission Cut-Planes And Generation Dispatch

Cut-planes are used in bulk and regional transmission studies to illustrate the capability of transmission paths to move energy from one location to another. They are hypothetical lines "cutting" through the circuits connecting two areas of the system.

By defining transmission cut-planes and specifying the load and generation levels to assume “upstream” and “downstream” of each cut-plane, the Non-Firm (N-0) and Firm (N-1) transfer limits across the cut-plane can be assessed and upgrade options compared.

“Upstream” is the source side of the cut-plane and “downstream” is the sink side. If the transfer limit from north to south across a particular cut-plane is being studied, the north side would be considered “upstream”. If the transfer limit from south to north across the same cut-plane is being studied, the south side would be considered “upstream”.

There are three basic types of transmission cut-planes, (1) source, (2) sink and (3) network cut-planes.

Several of the more significant cut-planes in the B Hydro transmission system are shown in the BCTC “Information Release” document (dated January 30, 2008) entitled, *“Bulk Transmission System Cut-Planes Total Transfer Capability (**TTC**)”.*

5.3.1 Source Cut-Plane Studies

A “source” cut-plane study involves a cut-plane that divides a region of surplus generating capacity (i.e., a generation-rich region) from the rest of the integrated system. An example of a source cut-plane study would be a study of the transfer capability of the transmission system connecting the G.M. Shrum (**GMS**) and Peace Canyon (**PCN**) plants to the Williston (**WSN**) substation. In this case the transfer capability northward is not of interest because the amount of dependable generating capacity north of WSN far exceeds the local load requirements and many generators would have to fail before the load could not be served even without a transmission connection into the region from the south.

The transfer capacity southward is of interest because the Peace region contains a significant portion of the total system DGC (i.e. GMS and PCN plants) and therefore providing adequate transmission capability to deliver that capacity to the aggregate system load is important.

5.3.2 Sink Cut-Plane Studies

A “sink” cut-plane study involves a cut-plane that divides a high load (i.e., load-rich) region that has little DGC, from the integrated system. An example of a sink cut-plane study would be a study of the transfer capability from the Lower Mainland to Vancouver Island.

It is possible that the same cut-plane can be the subject of both a source cut-plane study and a sink cut-plane study if the aggregate MPO of the region is greater than the minimum load, but the aggregate DGC of the region is less than the peak load. This might be the case if there were a large amount of wind resources connected to a region with a peak load in the same range as the aggregate MPO of the wind resources. On a warm windy night when the load is light, the transmission system would be loaded in one direction and on a hot calm day during the peak load period the flow would be in the opposite direction.

5.3.3 Network Cut-Plane Studies

A “network” cut-plane study is one in which there is more than one group of “generation-rich” or “load-rich” regions on one side or the other of the cut-plane. An example of a network cut-plane study would be the study of the transfer capability across the Interior to Lower Mainland (**ILM**) portion of the system. A series of nomograms can be used to define the capability of a network cut-plane for the full range of possible generation dispatch assumptions.

In a network cut-plane study, the worst-case contingency depends on how the generation is dispatched among the different groups of generators. For the ILM network, the critical outage would be to one of the lines connecting the Nicola (**NIC**) substation to the Lower Mainland (e.g., 5L81) when generation dispatch from the South Interior plants (Mica, Revelstoke, Kootenay Canal, Seven Mile, etc.) was high. With high Peace generation, an outage to one of the lines connecting the Kelly Lake (**KLY**) substation to the Lower Mainland (e.g., 5L42) would be the most onerous.

When studying a network cut-plane, the aggregate DGC, SC and MPO levels of two or more groups of generating plants need to be defined. For example, in the case of the ILM, the aggregate SC and MPO generation values would be needed for (a) the group of generators located east of Nicola and (b) the group of generators located north of Kelly Lake to assess the Firm and Non-Firm ILM limits and the aggregate DGC values would be needed for all plants west and south of Kelly Lake and Nicola.

5.3.4 Load Levels

For “sink” cut-plane studies, peak load conditions (either summer or winter) are likely the most onerous and should be used to represent worst-case conditions. The same is likely true of “network” cut-plane studies.

For “source” cut-plane studies, both the generation and the load in the area of the generation as well as the system load needs to be considered for determining the worst-case scenario. Often a light load scenario in the generation area would represent the worst-case load conditions. However, it may be unreasonable to study the lightest load possible as discussed in section 5.3.5.

5.3.5 Light Load Studies Related to Integration of New Generation

Light load conditions would be the worst-case generation/load combination for "source" cut-plane studies. However, under light load conditions there is an abundance of generating capacity in the system. Hence, when assessing the Firm and Non-Firm transmission capacity required to transmit surplus generating capacity out of a region or across the bulk system, light load studies should permit N-0 generation restrictions up to the level that would result in generating capacity reserves as low as 15 per cent[13] considering the amount of generating capacity that should be expected to be out of service for maintenance (and therefore unavailable as reserve capacity) and the load level for the season/month being studied.

For N-1 studies, generation shedding and/or run-back (turn-down) should be allowed up to the level at which the Automatic Generation Control (**AGC**) system is suspended (presently 1,200 MW), provided the remaining generating capacity reserve level does not drop below 15 per cent considering the amount of capacity that should be expected to be out-of-service for maintenance.

The generating capacity that should be assumed to be out-of-service and unavailable by month should match that assumed in the most relevant LOLE[14] study available. In the absence of specific information on generator maintenance schedules, the percentages of total installed generating capacity assumed to be out of service for maintenance should be as shown in the following table:

[13] A value of 15 per cent for generating reserves was chosen after reviewing the results of monthly contributions to the total annual LOLE value. The contribution to annual LOLE was insignificant in months with greater than 15 per cent generating capacity reserve. Refer to section 4.2 for a discussion of LOLE.

[14] LOLE: Loss of Load Expectation is a probabilistic assessment of generating capacity adequacy.

Table 1 F2012 LOLE Study

	Capacity Out-of-Service (on Maintenance)	
Month	**(MW)**	**(% of Total)**
OCT	433.09	3.7
NOV	147.90	1.4
DEC	0.00	0.0
JAN	0.00	0.0
FEB	0.00	0.0
MAR	851.51	7.3
APR	1,506.13	12.9
MAY	1,605.90	13.7
JUN	1,589.13	13.6
JUL	1,160.03	9.9
AUG	965.06	8.3
SEP	523.16	4.5

5.3.6 Dependable Peaking Units Backing up Intermittent Resources in a Load Area

In some cases, peaking generating units can serve to back up intermittent resources in a load region that is served by a constrained transmission connection. However, only the dependable capacity of some of those peaking units may be needed to achieve a system-wide LRB. In this case the worst-case generation dispatch should not have all of the peaking generating plants and all of the intermittent generating plants in the region generating at their maximum power output levels at the same time to determine the transmission capability required under normal system conditions (N-0). This is particularly important for assessing a bulk transmission cut-plane that is electrically down-stream of the transmission-constrained load region as described in section 5.2. Refer to section 4.3 for LRB resource stack implications of transmission constraints.

5.4 Integrating New Generation

This section deals with generation dispatch assumptions used in power system planning studies associated with integrating new generating plants.

5.4.1 Non-Firm (N-0) Transmission - Generation Dispatch

In general, to meet reliability requirements (i.e., economics ignored) in deterministic transmission planning studies conducted to determine transmission requirements for normal system conditions (N-0), the generation dispatch assumptions are:

(i) All plants located "upstream" of a cut-plane that contribute to achieving a LRB for the aggregate system (i.e., their "System Capacity" values are included in the LRB tables developed by the resource planner) are modeled at their seasonal MPOs to determine transmission capacity requirements for the most onerous, but normal, system conditions (e.g., the system load level used in the study would be the level at which the performance criteria would be most difficult to meet for the cut-plane being studied). Note that modeling extremely low load conditions may not be appropriate in some circumstances as discussed in section 5.3.5. Note also that if a unit that is upstream of a bulk system cut-plane is also downstream of a regional cut-plane and is committed as CRMR for that regional cut-plane, but is not included in the resource stack in the LRB for serving the aggregate system load, then that unit would be modeled as being out-of-service and the intermittent resource that it is backing up would be modeled at its MPO level or vice versa, but both would not be modeled as being at their MPO levels as discussed in section 5.3.6.

(ii) Each plant "downstream" of a transmission system cut-plane is modeled at the greater of its (i) minimum output level (possibly zero) or (ii) RMR or CRMR[15] commitment level. In high-level studies such as those conducted in the IRP process, the RMR commitment level is often, but not always, assumed to be the plant's DGC. Government directives and economic and contractual

[15] Refer to section 4.1 for a description/definition of CRMR.

considerations may moderate this assumption in some studies as discussed under "Coastal RMR" below.

- Coastal RMR: The *CEA* does not allow BC Hydro to count on the 905 MW DGC of Burrard Thermal in planning studies *("The authority must plan to rely on no energy and no capacity from Burrard Thermal …")* except as needed in the short term (a) as RMR until 5L83 enters service, (b) until the Mica Units 5 and 6 enter service and (c) as backup capacity during Meridian 500/230 kV transformer outages until the Meridian transformation capacity is increased. Presently, the aggregate DGC of all other Coastal plants is committed as RMR generation, but this may change for some plants depending on economic analyses (i.e., it could be less expensive to advance transmission reinforcements than commit to run expensive generating capacity as RMR during peak load periods). Committing to lesser RMR amounts that would advance the need for transmission reinforcements would involve an economic trade-off between the cost associated with advancing transmission grid upgrades and the savings associated with committing less regional generating capacity as RMR.
- No Manual Actions: In the operating timeframe, manual operator actions would be expected to take place continually as the system conditions are monitored. However, to meet planning criteria, no manual operator actions are to be modeled in either N-0 or N-1 transmission planning studies. If, under some normal (but perhaps rare) system conditions, a sudden increase in the output from intermittent plants (e.g., wind and RoR hydro), would cause a facility (e.g., line or transformer) to overload and the Transmission Customer is willing to accept generation restrictions to avoid an expensive transmission upgrade, the means to prevent the overload must be automatic and not rely on operator action.

5.4.2 Firm (N-1) Transmission - Generation Dispatch

For integrated system studies, the following generation dispatch assumptions are used in deterministic transmission planning studies that define Firm transmission capacity requirements for various system single-contingency (N-1) operating conditions:

(i) Generating Plants "Upstream" of the Cut-Plane being Studied:

- All plants, including intermittent resources like wind farms and run-of-the-river hydro plants, are modeled as operating at their MPO levels prior to the contingency. All peaker units including CRMR units whose capacity is needed to meet generating capacity adequacy criteria for the aggregate system are also modeled as operating at their MPO levels, but those CRMR peakers whose only role is to back up a regional intermittent resource to provide adequate local load reliability due to a regional transmission constraint would be modeled as being shut down. All upstream generating resources would be modeled at their SC levels following single contingencies (N-1) with Remedial Action Schemes provided to automatically reduce the aggregate generation in the upstream region from the MPO level to the aggregate SC level for bulk system studies (an additional 500 MW of generation shedding/runback is permitted in regional studies; see section 5.4.3). In the operating timeframe, manual operator actions would be expected to take place immediately following a contingency to prepare for the next set of possible contingencies, but to meet planning criteria, no manual operator actions are to be modeled in N-1 transmission planning studies.

  Each plant need not be reduced to its SC level, but the aggregate generation in the entire region is reduced to the sum of the SCs of all plants in the region. Note that in actual operation, generator shedding or run-back will often be applied to plants other than intermittent plants, but the aggregate effect would be equivalent to each intermittent resource in the upstream region being shed or run back to its SC level following the outage for bulk system studies and by an additional 500 MW for regional system studies.

- The MPO and SC used in the studies should be appropriate for the season being studied (e.g., a gas turbine might have a higher rating in the winter and the ratings of hydro plants with storage will depend on reservoir elevation that would vary seasonally).

(ii) Each generating plant (including intermittent resources) "downstream" of the cut-plane being studied is modeled as operating at the greater of (i) the plant's minimum output level (possibly zero) or (ii) the plant's RMR commitment level. In high-level studies such as those conducted in the IRP process, the RMR commitment level is often, but not always, assumed to be the plant's DGC. Government directives and economic and contractual considerations may moderate this assumption in some studies.

- BC Hydro may specify aggregate RMR generation capacities that are less than the aggregate total of the DGCs of all generating plants in the regions "downstream" of the cut-plane being studied, considering the operating costs and reliability risks associated with specific plants and other factors such as guidelines that may be established to assign generating capacity reserves on a regional basis. The transmission planning studies would identify the transmission system reinforcement needs consistent with the RMR commitment levels specified by the BC Hydro.

5.4.3 Generation Shedding/Run-Back

Generally, as a system reliability criteria, first contingency (N-1) generation shedding or run-back required to maintain system electromechanical or voltage stability and prevent overloading of equipment will be limited to the lesser of:

(a) the difference between the aggregate MPO and the aggregate SC in the region "upstream" of the cut-plane being studied for bulk system studies (500 MW more than this amount is allowed to be shed or run back for regional transmission studies[16]) and

(b) the maximum amount of generation loss that would not suspend the AGC system. Presently the AGC system is suspended when the interchange deviation exceeds 1,200 MW.

6 Upgrading From Single To Redundant Supply To A Load Region

The decision to upgrade the supply to a load area from a single radial line to two lines in parallel to provide N-1 reliability must consider a number of factors and weigh the reliability improvement against the expected cost. Some of the considerations include:

- The historical reliability of the existing line;
- The dependable generating capacity and reliability of local generation;
- The size and nature of the area load or the critical loads in the region;
- The results of a composite system reliability analysis using BC Hydro's "MECORE" or a similar probabilistic program to estimate the expected reduction in customer outages associated with redundancy options;
- The expected customer outage costs[17] considering the amount of different classifications of loads in the region; and
- DSM options including Direct Control Load Management[18].

[16] Allowing an additional 500 MW to be shed or run back under N-1 conditions on a regional cut-plane aligns with the criterion of permitting up to 500 MW of dependable generating capacity to be connected to the system via a single transmission line.

[17] For data on customer outage costs refer to BCUC IR 2.162.1 from 5L83 Proceeding (2008-Mar-6) and BCUC IR 3.186.2 from VITR Proceeding (2006-Jan-25).

[18] As defined by NERC: http://www.nerc.com/files/Glossary_of_Terms.pdf.

In general, sufficient dependable generating capacity is provided to supply the residential and commercial loads in a region that has a single radial transmission connection to the rest of the system.

7 Economic Dispatch

Transmission line outages are infrequent and usually of very short duration. Hence, N-0 transmission system limits are normally applicable in economic dispatch studies, like those undertaken using BC Hydro's Generalized Optimization Model (**GOM**) program to assess the "energy-shaping" benefits of new generating units.

In addition, while planning studies may be based on limiting the amount of generation shedding to the aggregate difference between MPO and SC "upstream" of the limiting cut-plane as indicated in section 5.4.3, the limit on the amount of generation shedding armed in the actual operating timeframe is based on the amount of generating capacity that can be shed without violating the NERC/WECC Disturbance Control Standard (**DCS**) that requires the Area Control Error (**ACE**) to be returned to zero within 15 minutes.[19] A reasonable limit on generation shedding for economic dispatch studies is the maximum generation loss that does not trigger AGC suspension. This is presently approximately 1,200 MW.

8 Imports And Exports

8.1 Long-Term Firm Point-To-Point (LTFPTP) Commitments

All applicable LTFPTP commitments should be modeled in each transmission study, including the following BC Hydro contracts:

- BC Hydro holds a 230 MW LTFPTP transmission reservation on the B.C.-U.S. path for the Skagit River Treaty obligation to deliver that capacity to Seattle City Light (**SCL**), but the expected transfer level to SCL coincident with BC Hydro's

[19] The 15-minute Disturbance Recovery Period is stipulated in Clause R4.2 of the BCUC-approved NERC Standard BAL-002-0.

system peak load is only 123 MW. Nevertheless, in transmission planning studies, the SCL export is modeled as 230 MW because that is the capacity of the LFTPTP reservation which is used to determine the associated reservation payments.

- BC Hydro Generation (NERC/OASIS customer code BCPS) currently holds 249 MW in LTFPTP transmission reservations on the Alberta-B.C. path (TSR #71583712 and 71685250). These reservations have full roll-over rights. However, there is a historical operating practice whereby BC Hydro's generation scheduling group (**PSOSE**) will reduce either the total generation east of the West of Selkirk (**WoS**) or the West of Ashton-Selkirk (**WoAS**) cut-plane or the amount of BC Hydro's import from Alberta, if necessary, to avoid congestion on the BC Hydro cut-planes west of Cranbrook (i.e., WoS, WoAS and ILM).

In addition, the TRMs of the two WECC paths (65 MW for Path 1, Alberta-B.C. or 50 MW for Path 3, B.C.-U.S.) should be modeled in transmission planning studies for the purpose of determining transfer capabilities.

8.2 FortisBC Power Purchase Agreement

BC Hydro's Network Load includes a 200 MW delivery to FortisBC under the Power Purchase Agreement (**PPA**). This 200 MW is deemed to be delivered from BC Hydro's Network Resources to the Okanagan point of interconnection (**POI**) (170 MW) and the Princeton POI (30 MW).

FortisBC is modeled as a region within the BC Hydro system because FortisBC is not a control area since it doesn't have an AGC system to control the flows over the various lines connecting the FortisBC system to the rest of the BC Hydro integrated system. BC Hydro dispatches all of plants on the Kootenay, Columbia and Pend d'Oreille rivers including those operated by FortisBC, Columbia Power Corporation and Teck Metals Ltd.

8.3 Columbia River Treaty Down-Stream Benefits

The Canadian Entitlement (**CE**) portion of the Columbia River Treaty Downstream Benefits are not assumed to be equivalent to dependable system capacity or as equivalent to Coastal RMR in transmission planning studies unless it is specified as such in BC Hydro's IRP or NITS Applications. Except as specifically designated, the CE is not considered as a source of either dependable capacity or firm energy for the BRP or CRPs or as Coastal RMR.

However the CE is a potential source of firm energy and dependable capacity and CRPs may specify that the CE will be relied upon to supply a portion of the required system dependable generating capacity. In effect, BC Hydro retains the CE as an "operational contingency" to meet Firm load commitments for situations where planned generation or transmission additions are delayed. When the CE is designated as a dependable Network Resource, single-contingency (N-1) transmission capacity should be provided to allow CE import levels between zero and the amount indicated in the NITS data as "dependable".

Sufficient N-0 transmission capability should be provided to allow the full NITS-Designated CE amounts (e.g., 1,400 MW beyond five years from the current date). This means that, when studying the ILM transmission requirements for the condition of maximum South Interior generation, the initial conditions should consider that the maximum CE amounts might be imported (i.e., maximum inflows on the eastern tie at Nelway, that would increase ILM loading) with the generation in the Northern Region reduced to achieve a load/resource balance. For N-1 conditions the CE should be assumed to be reduced to the dependable values shown in the NITS data. How the CE is split between western and eastern interties would be determined from power flow studies since the CE splits according to physics. The typical CE split (11/14$^{\text{ths}}$ on the western ties and 3/14$^{\text{ths}}$ on the eastern ties) are from the Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement dated March 29, 1999.

8.4 Rio Tinto Alcan Imports And Exports

BC Hydro specifies the Firm (equivalent to dependable generating capacity) and Non-Firm import and export transfers to assume for the intertie with Rio Tinto Alcan (**RTA**)[20] for transmission planning studies. The level of import on the RTA intertie to be assumed coincident with operation of all northern generating plants at the maximum aggregate dispatch level is specified for defining normal (N-0) and contingency (N-1) transmission requirements for the specific transmission systems, for example, south of the Williston substation.

9 References

1. BCUC-Approved NERC Reliability Standards: http://www.nerc.com/page.php?cid=2|20

2. Western Electricity Coordinating Council (**WECC**) Interpretations: http://www.wecc.biz/Standards/Interpretations/Forms/AllItems.aspx

3. BC Hydro's Open Access Transmission Tariff (**OATT**): http://transmission.bchydro.com/regulatory_filings/tariff/

4. BCUC Decisions Index: http://www.bcuc.com/DecisionIndex.aspx

[20] BC Hydro's station code for the Rio Tinto Alcan facility is "ALN".