BRIEF ON DETERMINING TRANSMISSION CAPACITY FOR INTERMITTENT RESOURCES

BC Hydro's Current Practice
(Draft d02a; 2013-May-31)

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A. INTRODUCTION

This document describes BC Hydro's current practice for determining the transmission capacity associated with integrating regions with significant amounts of intermittent generation resources like wind and run-of-river hydro plants.

B. SYSTEM LOAD-CARRYING CAPABILITY

BC Hydro uses Loss-of-Load-Expectation (**LOLE**) studies to determine the level of generating capacity reserves to use in long-term planning studies. Presently reserves are 14% of the load-carrying capacity of the aggregate of all generating resources in the system.

The total load-carrying capacity in any given year must exceed the total system coincident load by 14% (ie, total load-carrying capacity minus 14% must be greater than the hourly system peak load). This is the basis for BC Hydro's Load-Resource Balance (**LRB**) tables that demonstrate that the planned total system generating capacity exceeds the forecasted load by 14% in each year of the 20-year plan.

The Effective Load-Carrying Capability (**ELCC**) to assign to a variable resource like a wind farm is determined as follows:

1. An LOLE study without the wind farms is done with the load duration curve scaled up or down to achieve an LOLE of 1 day in 10 years.
2. A 5-step Capacity/Probability table is added to the other resources in the LOLE study to represent the aggregate of all wind farms that will be in service in the study year.
   - 2.1. The load is scaled up until the LOLE value is the same as without the wind farm (1 day in 10 years).
   - 2.2. The difference in the peak load values is considered to be the ELCC contribution of all wind farms.
   - 2.3. The ELCC value of the wind farms is added to the resource stack in the LRB tables (ie, a 100 MW wind farm with an ELCC value of 25 MW is considered equivalent to a 25 MW large storage hydro plant).
3. The aggregate ELCC value of all wind farms can be assigned on a pro rata basis to each site.
4. This is a slightly simplified description of BC Hydro's LOLE analysis process. BC Hydro uses a 1 day in 10 years criterion using load duration curves formed from daily peak values (ie, 365 points per year). However, BC Hydro calculates LOLE on a monthly basis, to account for unit maintenance, and the monthly values are summed.

C. TRANSMISSION REQUIREMENTS

While generating capacity adequacy is determined on a probabilistic basis (based on LOLE analysis), transmission capacity requirements are identified using deterministic studies. Typically the worst-case pre-contingency conditions are modeled in terms of generation dispatch and load levels and a worst-case fault (usually 3-phase fault at the sending end of a critical transmission line) is simulated in powerflow and dynamic studies. The results are analyzed to ensure performance standards are met.

Since LOLE studies assume a perfectly reliable transmission system with no constraints, traditionally the transmission requirements were based on meeting performance standards without resorting to generator shedding when the system did not contain any significant amount of intermittent generating resources. Now that there are significant amount of intermittent capacity, the no-shedding rule has been modified to allow shedding down to the aggregate ELCC capacity on the upstream side of a cut-plane.

The general rules for transmission capacity associated with integrating a region containing a surplus of generating capacity are:

1. Sufficient Non-Firm (N-0) transmission capacity is provided on the Bulk Electric System (**BES**) to allow all “up-stream” generators to operate at their Maximum Power Output (**MPO**) levels with all transmission equipment in-service during the worst case load condition.
2. Sufficient Firm (N-1) transmission capacity is provided on the BES to allow the aggregate of all upstream generators to operate at the aggregate ELCC of the upstream group of generators. This means that, after the fault, the wind farms and other intermittent plants can operate at their MPO levels and the area’s large hydro storage plants can be modelled as operating below their MPO levels such that the total generation in the upstream area is no greater than the aggregate ELCC of all the generators in the upstream area). This maintains the validity of the LOLE study assumption of a perfect transmission network because ELCC values are used for determining Firm (N-1) transmission needs (ie, we are only counting on the ELCC values of intermittent plants in the LRB, so that is the value for which Firm transmission capacity is provided).
3. Curtailment of upstream generation is permitted for single contingencies provided the resulting remaining total system generating capacity reserves do not decrease below 15% considering generating capacity expected to be out for maintenance in the season/month being modelled.

For load “pockets” where the need to upgrade the transmission system depends on how much reliance is placed on the local generating plants, the following rules are being considered by BC Hydro:

1. The “Dependable Generating Capacity” (**DGC**) to assign to a generating plant is based on the output level that is expected to be exceeded 98% of the time (not considering equipment forced outages, but only “fuel” limitations) in each of the two winter months (December and January) that the system peak load is expected to occur.
2. The maximum amount of Reliability-Must-Run (**RMR**) capacity to assign to a region is the aggregate DGC minus the greater of either (a) 14% or (b) the DGC of the largest generator.

The rationale for these two rules is:

a. The RMR capacity committed will defer transmission upgrades and transmission lines are very reliable compared to generating units. The forced outage rate (**FOR**) of a transmission line is usually in the 0.001% to 0.300% range whereas a typical hydro unit has a FOR of about 3.500% and the FORs conventional fossil-fired steam turbine-generators are about 6.410%[1]. The bottom line is that a generating unit is usually much less reliable than a transmission line so they can’t be considered equivalent sources for supplying Firm load.
b. Keeping 14% DGC in reserve is consistent with the 14% reserve applied on a system-wide basis.
c. Being able to survive the loss of the largest generator is prudent for situations where there is one very large unit and one or more small units.

[1] FORs are from the Canadian Electrical Association (CEA) 2011 Generation Equipment Status Annual Report for the period 2007-2011 for units 100 MW and larger.