Q. **Reference Application**

Please provide a summary of Hydro planning criteria used in formulating the 2021 Capital Budget Application.

A. Rural Planning Criteria are applied to systems operating at 25 kV and below. For Diesel Generation Plants, please refer to CA-NLH-019, Attachment 1 for the Rural Planning Standard "Rural Isolated Systems Generation Planning Criteria Doc # RP-S-002." For Distribution Systems please refer to CA-NLH-019, Attachment 2 for the Rural Planning Standard "Distribution Planning Criteria Doc # RP-S-003."

Transmission Planning Criteria are applied to systems operating at 46 kV and above. Please refer to CA-NLH-019, Attachment 3 for the NLSO[1] Standard "Transmission Planning Criteria Doc # TP-S-007." Considerations associated with the application of these criteria are presented in Newfoundland and Labrador Hydro's response to LAB-NLH-004 of this proceeding.

[1] Newfoundland and Labrador System Operator ("NLSO").

RURAL PLANNING STANDARD

Rural Isolated Systems Generation Planning Criteria

Doc # **RP-S-002**

Date: 2020/08/21

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1 PURPOSE

The purpose of this document is to present Rural Isolated Generation Planning Criteria to be applied to the Diesel Generation Plants within the Province of Newfoundland and Labrador.

2 TERMS, ABBREVIATIONS, AND ACRONYMS

Firm Capacity means the amount of capacity that can be reasonably guaranteed from a generating unit at a particular instant when required. In the case of capacity planning, it describes the capacity that can be expected from a diesel generating plant during the system peak load.

Standby Power[1]: Output available with varying load for the duration of the interruption of the normal source power. Average power output is 70% of the standby power rating. Typical operation is 200 hours per year, with maximum expected usage of 500 hours per year.

Prime Power[1]: Output available with varying load for an unlimited time that is typically 90% of Standyby Power Rating. Average power output is 70% of the prime power rating. Typical peak demand is 100% of prime rated ekW with 10% overload capability for emergency use for a maximum of 1 hour in 12. Overload operation cannot exceed 25 hours per year.

Continuous Power[1]: Output available with non-varying load for an unlimited time that is typically 70% of Standyby Power Rating. Average power output is 70-100% of the continuous power rating. Typical peak demand is 100% of continuous rated ekW for 100% of operating hours.

[1] Based on the IOS8528 Standard

3 INTRODUCTION

A Rural Isolated System is an electric power system that is isolated from either the Island or Labrador Grid, and is typically supplied by diesel based generation. Hydro has established criteria related to the appropriate reliability, at the generation level, for the System that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the System to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities for Rural Isolated Systems the following have been adopted.

4 RURAL PLANNING CRITERIA

4.1 Capacity

Capacity for Rural Isolated Systems is provided by Diesel Generating Plants which house a number of Diesel Generator Sets (Gensets). The minimum number of units in a diesel plant is three, and typical plant size is from three to four units, although some (typically larger) plants contain more units. The prime power rating of the gensets is used to calculate the firm capacity in the rural isolated diesel plants. Gensets are assumed to be capable of achieving their respective nameplate ratings throughout their lifecycle.

In some cases power is also supplied to the system by alternative energy sources such as wind, solar, and small hydro. To date, wind and solar are considered as non-firm energy sources even when coupled with an energy storage system. That is, the wind and/or solar generation is not considered to provide firm capacity to the system during peak load. This is due to the random nature of the energy supply (wind/solar) which will not necessarily be present when it is needed. In the case of hydro-electric plants, run-of-river plants, are treated the same as wind or solar, and provide no firm capacity to the system during peak load. A hydro-electric plant with a storage reservoir will provide some degree of firm capacity to the system. The amount of capacity is dependant on the particular site and the design of the plant.

Hydro applies firm capacity criteria, which considers all the firm power sources available to the system, when determining the amount of capacity needed to supply the system's peak load according to the five year load forecast. The criterion used to guide Hydro's planning activities in relation to system capacity is described below.

4.1.1 Firm Capacity Planning Criteria

Hydro's generation reliability criterion for the Isolated Rural Systems is stated as follows: Hydro shall maintain firm generation capacity to meet the system peak load. Firm generation capacity is defined as the total installed capacity on the system not including non-firm energy sources as noted above minus the largest single unit. Exemptions or modifications to this criterion may be considered in the following situations:

- Additional generation may be prudent in situations where the introduction of a subtransmission system supplying multiple communities decreases existing system reliability.
- Less generation may be prudent in situations where non-firm generation has a historical record of operating at a low unavailability rate.
- Additional generation may be prudent in situations where major diesel plant modifications, such as the construction of a new diesel plant or major extension, are planned and the cost to add additional generation is of minor incremental cost.

Rationale:

The Firm Capacity Planning Criteria covers a first contingency situation. It is considered to provide a reasonable level of reliability to customers in the Rural Isolated Systems, and gives a good compromise between cost of service and reliability. Hydro has a long standing practice of using this criterion with good success. A survey conducted by Hydro in 2007 has confirmed that this criterion is similarly practiced in other utilities. This criterion can be reasonably considered to be an industry standard practice.

4.2 Energy

Energy for Rural Isolated Systems is provided from either Type A (Arctic Grade), or Type B Diesel Fuel supplied by a local fuel vendor or stored on site by Hydro. Where cost-effective, Hydro will contract with a local fuel vendor for supply of diesel fuel to the diesel plants. In cases where this arrangement is not feasible, or not possible, Hydro will maintain long-term bulk fuel storage at the site. The amount of fuel to store is planned such that the diesel plant can supply energy requirements of the system over the winter period when fuel deliveries to the site are unavailable.

4.2.1 Vender Delivered Fuel:

In the case where Hydro relies on a contract with a local fuel vendor, the following criteria are used to guide Hydro's planning criteria.

- Sufficient fuel shall be stored on site, such that the energy requirements of the system can be met for two weeks at all times of the year.
- The total available fuel storage capacity required on site shall meet the energy requirements of the system for a minimum of three weeks at all times of the year.

Assumptions:

- The local fuel vendor has enough storage to meet Hydro's winter fuel requirements.
- The local fuel vender is scheduled to fill up Hydro's storage at least once every seven days.
- If more than twenty-one days of storage is available, then deliveries may occur less often.
- If a location has a much higher, or lower risk of delay in fuel storage than then typical, additional, or less fuel storage may be required.

Rationale:

For planning purposes a fuel delivery of once every seven days is assumed because fuel carrying ferries operate on a weekly schedule. The Fuel Storage Planning Criteria covers the contingency situation of a one week delay in fuel delivery. If the vendor fills Hydro's storage every seven days and Hydro's fuel storage is large enough for at least twenty-one days of fuel then there should always be at least two weeks of fuel in storage. If the vendor cannot supply fuel on the seventh day due to an emergency (pipe failure, pump failure, or ferry delay, etc.) there is two weeks fuel available for backup.

4.2.2 Bulk Fuel Storage

In the case where Hydro must maintain long-term bulk fuel storage, the following criteria are used to guide Hydro's planning activities.

- Island Isolated Systems; sufficient fuel shall be stored on site, such that the energy requirements of the system can be met for four consecutive months.

- Labrador Isolated Systems; sufficient fuel shall be stored on site, such that the energy requirements of the system can be met for nine consecutive months.

Assumptions:

- Final Fuel delivery via shuttle tanker is in late November.
- Hydro's fuel requirements are communicated to the vendor in the fall before the final fuel delivery.

Rationale:

The Fuel Storage Planning Criteria covers a first contingency situation. It is considered to provide a reasonable level of reliability to customers in physically isolated communities, and gives a good compromise between cost of service and reliability. Hydro has a long standing practice of using this criterion with good success. A survey conducted by Hydro in 2007 revealed that most other utilities surveyed only maintain short-term fuel storage and rely on deliveries from fuel vendors. Only one utility surveyed maintained long-term bulk fuel storage. It appears that fuel storage practices are region specific and dependant on the local resources available (i.e. road access, local fuel vendor, etc.).

4.3 Diesel Plant Equipment

In addition to generating capacity, and energy, Hydro plans the capacity of the major diesel plant equipment that is responsible for getting the power from the individual diesel units to the power distribution system. The components covered under this criterion are the Main Breaker, Main Bus, and Service Conductors and is defined as follows:

Diesel Plant Equipment Capacity Planning Criteria

No equipment shall be loaded above 100% of its rated capacity at rated ambient temperature.

Assumptions:

- The ratings are continuous ratings.
- Ambient temperature is thirty degrees Celsius.

4.4 Diesel Plant Substations

Capacity planning of diesel plant substations (step-up transformers) is covered under Hydro's Distribution Planning Criteria. The criteria are re-iterated here since the substation forms the critical interface between the diesel plant and the distribution system.

Substation Capacity Planning Criteria

Transformers at Substations shall not be loaded above 110% of the nameplate rating.

In the case of diesel plant substations; a spare shall be retained on site such that in the event of the loss of a single unit; the spare can be installed to restore power within a reasonable time frame. The standard substation is an aerial bank of three single-phase transformers connected in a three-phase bank. The maximum size aerial bank is 1500 kVA (3x500 kVA). This transformer size was selected since it is considered to be the largest size transformer that can be handled without assistance from a bucket truck, or crane.

If transformer capacity exceeding the maximum size aerial bank is required a three-phase padmount transformers may be used. Due to the size of these units and the remote nature of these plants, the equipment and personnel required to replace a three-phase transformer may not be available when needed. To prevent a prolonged system outage, in the event of a three-phase transformer failure, a second padmount transformer may be installed and available as a spare to use when required.

Document Summary

Document Owner:	Rural Planning
Document Distribution:	Rural Planning

Revision History

Revision	Prepared by	Reason for change	Effective Date
1	Tyler Stevens	Updated and included in DMS	2020/08/21

Document Approvers

Position	Signature	Approval Date
Team lead, Rural Planning	Scott Henderson	Sept 17, 2020

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RURAL PLANNING STANDARD

Distribution Planning Criteria

Doc # **RP-S-003**

Date: **2020/10/02**

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1 Purpose

Hydro's distribution planning criteria are established to ensure an adequate supply of power to customers served on Hydro's distribution systems. As a general rule to guide Hydro's planning activities the following criteria have been adopted.

2 Voltage Level Criteria

A) The range of normal operating voltage is based on the Canadian Standard CSA CAN3-C235-83 ("Preferred Voltage Levels…") and the CEA "Distribution Planner's Guide".

B) Voltage Unbalance – maximum 2% voltage unbalance.

C) Voltage Flicker Limit – maximum of 5% voltage flicker.

D) Temporary Overvoltage – maximum 110% overvoltage

2.1 Operating Voltage

Hydro uses the CSA standard *CAN3–C235–83 – Preferred Voltage Levels for AC Systems 0 – 50,000 V* as the guide for determining acceptable steady-state voltage limits at customers' service entrances. This is a National Standard of Canada that establishes a guideline for voltage standards for AC Systems in Canada. It was adopted by Hydro as its standard for the range of acceptable voltages that will be provided to customers and is used by utilities across Canada. A standard for voltage levels is necessary because the devices connected to the electrical system are designed to operate within a certain range of voltages. When voltages supplied to the device deviate from this acceptable range, the device can be damaged or fail to function properly. The standard is meant to ensure that the devices connected to the electrical system will receive voltage within their normal operating range so that they function normally and damage does not occur.

The standard refers to two separate operating conditions, normal and extreme. The normal operating condition is applied when the distribution system is operating as designed and not experiencing continuous operation outside design limits. The extreme operating condition is applied during continuous operation of a power system outside of design limits and planned capital or operating work is scheduled to be carried out to correct the issue. These conditions do not include voltages levels experienced during fault conditions or heavy starting loads.

Under normal operating conditions where there are no operational anomalies and the feeder is performing as designed, the customer service entrance voltage must be held between a minimum of 110 V for single-phase customers and 112 V for three-phase customers and a maximum of 125 V for a nominal 120 V service. Table 1 displays the normal and extreme operating condition nominal voltage ranges for many types of electrical services.

Table 1: Recommended Voltage Variation Limits for Circuits up to 1000V, at Service Entrances[1]

Nominal System Voltages	Voltage Variation Limits Applicable at Service Entrances			
	Extreme Operating Conditions			
		Normal Operating Conditions		
Single Phase (V)	**Lower Limit**		**Upper Limit**	
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635
Three Phase 4-Conductor (V)				
120/208Y	110/190	112/194	125/216	127/220
240/416Y	220/380	224/338	250/432	254/440
277/480Y	245/424	254/440	288/500	293/508
347/600Y	306/530	318/550	360/625	367/635
Three-Phase 3-Conductor (V)				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

The standard also states that primary service voltages are to be supplied within six percent of the nominal system voltage.

Under extreme operating conditions the distribution system is operating outside of the normal operating voltage limits and an operational anomaly has been identified on the system. In this case, work must be planned to correct the deficiency so that voltages remain within the normal operating condition limits. During extreme operating conditions, the customer service entrance nominal voltage must range from a minimum of 106 V for single-phase customers and 110 V for three-phase customers to a maximum of 127 V for a nominal 120 V service.

If the customer service entrance nominal voltage falls outside of the extreme voltage range as outlined in the CSA standard, emergency work must be completed as soon as possible to rectify the issue. If not, damage to customer equipment may occur. Hydro is responsible for ensuring voltage levels up to the service entrance, i.e. weatherhead, are within stated limits.

The above CSA standard has been adopted by Hydro to ensure customer service entrance voltages remain within the stated limits. However, planning engineers complete system design and analysis using nominal voltages on primary distribution feeders. To relate the two, the System Planning Department references the CEA Distribution Planners Manual. The manual provides estimates of the

[1] From CSA standard CAN3–C235–83 (R2006) – Preferred Voltage Levels for AC Systems 0 – 50,000 V, Table 3 - Recommended Voltage Variation Limits for Circuits up to 1000 V, at Service Entrances.

average voltage drop that can be anticipated between the primary and the service entrance to define a minimum and maximum planning voltage on a 120 V base for the primary distribution line.

Table **2** and Table 3 outline the Hydro standard voltage drop for each line section and transformer between the primary conductor and the service entrance for single phase and three phase customers respectively.

Table 2: Preferred Voltage at the Primary for Single Phase Customers

		Voltage (120 V Base)	
		Heavy Load	**Light Load**
Service Entrance Voltage*		110	125
Voltage Drop at	Service Drop Wire	1	0.375
	Secondary Conductor	2	-
	Distribution Transformer	3	1.125
Total Voltage Drop from Primary to Service Entrance		6	1.5
Voltage at Primary		116	126.5

Note: Some customers are supplied from express service drops. Therefore, no secondary voltage drop occurs under the light load condition.
*** Hydro is responsible for voltage up to the service entrance.**

Table 3: Preferred Voltage at the Primary for Three Phase Customers

		Voltage (120 V Base)	
		Heavy Load	**Light Load**
Service Entrance Voltage*		112	125
Voltage Drop at	Service Drop Wire	1	0.375
	Secondary Conductor	-	-
	Distribution Transformer	3	1.125
Total Voltage Drop from Primary to Service Entrance		4	1.5
Voltage at Primary		116	126.5

Note: 3Φ General Service Customers are normally supplied from express drops off their own transformer bank. Therefore, no secondary voltage drop occurs.
*** Hydro is responsible for voltage up to the service entrance.**

Therefore, Hydro uses a planning voltage range of 116 V to 126.5 V on distribution primary lines, assuming a 120 V base.

2.2 Voltage Unbalance

Voltage unbalance occurs when loads are not equally distributed across all three phases of a distribution feeder. The percentage voltage unbalance is calculated as the maximum phase voltage deviation from the average voltage, divided by the average voltage, multiplied by 100%. It is common on many Hydro distribution systems to have long single phase lines with large end of line loads which can increase voltage unbalance. A feeder experiencing a high percentage of voltage unbalance can cause excessive motor heating, increasing the likelihood of failure.

2.3 Voltage Flicker

Voltage flicker is a transient phenomenon that occurs when large loads are switched on the system causing an instantaneous change in voltage. Usually this is experienced during motor starting or pick-up of a large customer load. In these cases, a dip in voltage is experienced due to the increase in current flow, causing lights to flicker. This can dim lighting and interrupt motor operation. Hydro will allow a maximum of 5% voltage flicker before work must be initiated to correct the problem. If voltage flicker worsens, the problem becomes much more noticeable and pronounced. Hydro addresses flicker at the operational level by setting limitations on the amount of current the system can supply to a customer without causing disturbances to other customers on the system.

2.4 Temporary Overvoltage

Temporary overvoltage is an increase in ac voltage greater than 1.1 pu for a duration longer than 1 min. Overvoltages can be the result of load switching (e.g., switching off a large load) or of variations in the reactive compensation on the system (e.g., switching on a capacitor bank). Poor system voltage regulation capabilities or controls can cause overvoltages.

3 Equipment Loading

Increases in customer load on distribution feeders can lead to overloading of overhead conductor and/or related equipment. A detailed load flow analysis will indicate areas which are experiencing current overloads during peak load conditions. Equipment affected by overloads includes transformers, circuit breakers, reclosers, voltage regulators and switches.

Equipment loading shall be no greater that 100% of its planning rating. These ratings indicated the maximum peak load permitted on a system component during normal operating conditions. It is recognised that under emergency or abnormal operating conditions, such as after recovering from extended outages, system components may be operated above the planning ampacity.

One abnormal operating conditions that is of particular importance when planning distribution systems is Cold Load Pick-Up (CLPU). CLPU is the amount of electricity that customers demand as they are re-energized after being without electrical service for an extended period of time. This is a function of the profile of customers/loads connected to a feeder. Generally, feeders with a high penetration of electric heating have the highest CLPU factors. The CLPU factor is defined as the CLPU divided by the normal winter peak load. If the maximum CLPU on a feeder is unknown, then the CLPU factor is assumed to be 2.0 and the duration is assumed to be 1.0 hour.

To manage CLPU on distribution system, utilities divide distribution feeder into sections so that not all load has to be picked up at the one time. This allows utilities to defer the substantial costs of upgrading s distribution system. However, doing this decreases the reliability of the system in terms of the System Average Interruption Duration Index (SAIDI) because customers are subjected to longer outages. For this reason only two designated sections may be permitted per feeder. These sections are separated by a sectionalizing switch that shall be located such that it maximized the planning ampacity for the system.

The optimum location for a sectionalizing switch is at the point where 66.67% of the load is on the first portion of the feeder and 33.33% of the load is on the second section of the feeder. Under this situation when recovering from an extended outage, when the first section of the feeder in energized the CLPU will be 133.3% (66.67% x 2) of the full feeder peak load. After this load settles the load on the first section will be back to 66.67% of the feeder peak load. When the second section of the feeder in energized, the load on the second feeder will be 66.67% of peak load (33.33% x 2) and the total feeder load will be 133.3% of peak load (66.67% first section + 66.67% second section).

To include CLPU and sectionalizing into Hydro's planning ratings the following formula is used.

- Planning Factor = Sectionalizing Factor * CLPU Factor

Where:

- CLPU Factor = CLPU load/winter peak load, (assumed as 2.0 unless system specific data is available)
- Sectionalizing Factor = amount of load in first section of feeder, (assumed to be 66.67% of feeder load unless physical constraints prevent this)

As a result the Planning Factor will range between 1.33 and 2.0, indicating a temporary loading between 133% and 200% of normal peak load when recovering from a CLPU event.

Planning ratings are determined based on Equipment Rating and Planning Factor which vary depending on the equipment being studied. Below is a summary on how Planning Ratings are calculated:

A) Transformers and Voltage Regulators: Planning Rating = 100% of name plate rating
B) Overhead Bare Conductor: Planning Rating = Winter Ampacity / Planning Factor
C) Reclosers: Planning Rating = Overload Capability/Planning Factor

3.1 Transformers and Voltage Regulators

The thermal limits of distribution step down transformers, and voltage regulators are based on IEEE – C57.91-1981. This standard shows the amount of load a transformer can withstand without affecting its service life. Although the amount of load on these transformer varies by transformer type, it is necessary to plan based on the worst case scenario so only the lowest overload capability will be utilized.

The planning ampacity for distribution transformers will depend on the configuration of the substation:

- In a distribution substation, the planning rating of the transformer will be 100% of the 30^{o} C nameplate rating. By restricting the system peak load to the name plate rating, a 175% overload capability[2] provides capacity to restore a distribution system after an extended outage where CLPU is present.
- The planning ampacity for diesel plant substation transformer is provided in *RP-S-002 Rural Isolated Systems Generation Planning Criteria*

As stated above, CLPU on a particular distribution system may range from 133% of peak load to 200% of peak load depending on the sectionalizing ability of the distribution system. For distribution systems that contain one distribution feeder and where the CLPU exceeds 175% of the normal winter peak load, a sectionalizing switch may be required on the feeder to limit CLPU. Where substations contain two or more feeders and a CLPU potential greater than 175% of the name plate rating exists, in addition to sectionalizing, feeders may need to be restored on a sequential basis to limit CLPU.

[2] The 175% overload capability is based on a 25% loading bonus due ambient temperatures and a 50% loading bonus due to the equivalent load before a CLPU peak load.

3.2 Conductors

Overloads on bare overhead conductor are identified during load flow analysis for the particular distribution feeder. Hydro has adopted the IEEE738[3] method for calculating the continuous ampacity of overhead conductor based on ambient temperatures. Table 4 below shows the continuous and planning ampacities for Hydro's most commonly used aerial conductors.

Table 4: Conductor Planning Ratings

Size and Type	Cont. Labrador Winter Ampacity	Cont. Island Winter Ampacity	Planning Ampacities Planning Factor = 2.0		Planning Ampacities Planning Factor = 1.33	
			Lab Winter Ampacity	Island Winter Ampacity	Lab Winter Ampacity	Island Winter Ampacity
#4 Copper	226	196	113	98	170	147
#2 ACSR	244	213	122	107	183	160
1/0 AASC	358	317	179	159	269	238
2/0 AASC	412	365	206	183	309	274
2/0 ASCR	389	345	195	173	292	259
4/0 AASC	557	493	279	247	418	370
477 ASC	904	800	452	400	678	600

These ampacities indicate the maximum allowable amperage on an aerial conductor under any circumstance during winter. These calculations are based on the assumptions found in Hydro's Distribution Planning Assumptions Standard.

3.3 Reclosers

The planning rating for reclosers is based on the overload capability of the recloser. This overload capability varies by model type and manufacturer. For example, most of Hydro's reclosers are cooper VWVE reclosers. These reclosers have an overload capability of 150% for a maximum of 2 hours. Therefore the planning rating for reclosers will be overload capability of the recloser divided by the planning factor of the feeder. For the Cooper VWVE reclosers this will be 646 A.

3.4 Switches

Hydro has two standard types of switches, group operated switches and single-phase cutouts. Group operated switches are rated for load breaking and are operated by a single handle to break all phases at the same time. These switches do not use any fuses for line protection. Single-phase cutouts are used

[3] IEEE738 - IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors

for isolating sections of line once they have been de-energized, as they are not rated to break load. Cutouts, however, can be fused to a number of ratings depending on the protection requirements. For planning and analysis purposes, the System Planning Department uses 100% of the continuous current rating for switches. Gang switches are rated for 600A per phase, where solid blade (no fuse) cutouts are rated for 300A. If the cutout is fused, the rating then becomes the rating of the installed fuse.

3.5 Circuit Breakers

The planning rating for circuit breakers is based on the IEEE std C37.010-1979. This standard provides the overload capabilities of circuit breakers for ambient temperatures less than the 40 deg name plate rating.

3.6 Load Imbalance

Load imbalance occurs when customer loads are not equally distributed across all three phases of a distribution feeder. The percentage of load imbalance is calculated as the maximum phase load deviation from the average load, divided by the average load, multiplied by 100%. A highly unbalanced load on a feeder can lead to a high degree of voltage unbalance along the feeder due to varying voltage drop on the phase conductors. An unbalanced feeder will experience higher losses due to currents flowing in the neutral circuit.

Document Summary

Document Owner:	Rural Planning
Document Distribution:	Rural Planning

Revision History

Revision	Prepared by	Reason for change	Effective Date
1.0	Scott Henderson	Criteria added to DMS	2020/10/02
2.0	Scott Henderson	Modified transformer loading criteria to reflect 46kV transfer to TP	2020/10/02

Document Approvers

Position	Signature	Approval Date
Team lead, Rural Planning	Scott Henderson	2020/10/02

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NLSO STANDARD

Transmission Planning Criteria

Doc # TP-S-007

Date: 2020/10/02

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 PURPOSE

The purpose of this document is to present the NLSO Transmission Planning Criteria to be applied to the interconnected transmission system within the Province of Newfoundland and Labrador. These criteria shall be applied in accordance with NLSO Standard TP-S-003 - Annual Planning Assessment.

2 INTRODUCTION

A key function of the NLSO Transmission Planning Department is to ensure the coordinated development of a safe, reliable and economical transmission system for the benefit of users within the Province of Newfoundland and Labrador.

The transmission planning process requires the use of computer software to perform power system studies in order to demonstrate that the power system meets planning criteria for the present and future states of the system. When the simulations of the power system indicate that the system is not meeting the stated planning criteria, the transmission planning process is used to develop cost effective transmission system enhancements to ensure the system meets the planning criteria. The adherence to stated transmission planning criteria is critical in ensuring a long term reliable transmission system.

Within the electric utility industry, North American Electric Reliability Corporation (NERC) and Northeastern Power Coordinating Council (NPCC) standards provide the North American and regional reliability standards and criteria, respectively. While not a registered member of either entity, the NLSO Transmission Planning Department aligns its planning criteria with the recognized reliability organizations where practicable for the Newfoundland and Labrador Interconnected System.

This NLSO Transmission Planning Criteria sets out the specific acceptable pre- and post-contingency responses of the elements within the Newfoundland and Labrador Interconnected System rated 46 kV and above.

3 COMPLIANCE REQUIREMENTS

Newfoundland and Labrador Hydro and subsequently the NLSO, is not a registered entity with the North American Electric Reliability Corporation (NERC) or the Northeast Power Coordinating Council (NPCC). However, recognizing that the neighbouring jurisdictions are registered entities with respect to system reliability, the NLSO must make provisions for regional compliance. To this end the NLSO Transmission Planning Department participates in the Maine Atlantic Technical Planning Committee (MATPC) and in studies with neighbouring jurisdictions to ensure that there are no adverse impacts across the interfaces.

3.1 NERC Criteria

The NLSO Transmission Planning Department will assist its neighbouring jurisdictions to ensure that its interconnections meet the applicable criteria set out in the NERC Reliability Standards as they pertain to transmission planning. Note that these standards are applicable to the power system elements which are considered to be part of the **Bulk Electrical System** (**BES**) within the neighbouring jurisdiction. Information pertaining to the standards is available on the NERC website (www.nerc.com).

3.2 NPCC Criteria

The NLSO Transmission Planning Department will assist its neighbouring jurisdictions to ensure that its interconnections meet the applicable criteria set out in the NPCC Document Directory #1 “Design and Operation of the Bulk Power System”. Note that these criteria are applicable to the power system elements which are considered to be part of the **Bulk Power System** (**BPS**) as set out in the NPCC Document A-10 “Classification of Bulk Power System Elements” within the neighbouring jurisdiction. For new additions to the Newfoundland and Labrador Interconnected System the A-10 test shall be used to determine if a **BPS** element exists. Information pertaining to the standards is available on the NPCC website (www.npcc.org).

4 TRANSMISSION PLANNING CRITERIA

This NLSO Transmission Planning Criteria defines the specific acceptable pre- and post-contingency response of the power system for all elements 46 kV and above.

4.1 Computer Based Power System Models

The NLSO Transmission Planning Department uses the Power System Simulator for Engineers (PSS®E) program for completing its transmission planning/power system analysis studies. The Transmission Planning Department maintains system models in the current version of PSS®E used by NPCC for performing studies to ensure effective data exchange with neighbouring entities.

4.2 Pre Contingency Criteria

With all equipment in service under normal operation, power flow in all elements should be at or below normal rating and voltages shall be within acceptable limits. The ratings are defined in the NLSO Standard TP-S-001 - Transmission Facilities Rating Guide. This criterion applies to radial, local networks and primary transmission system elements within the Newfoundland and Labrador Interconnected System.

4.3 Single Contingency (N-1) Criteria

From normal system conditions, the Newfoundland and Labrador Interconnected System shall be able to withstand a single contingency. Historically a single contingency has been considered as an event that leads to the loss of a system element. The historical definition of a single element loss on the Newfoundland and Labrador Interconnected System has been the loss of a:

- Transmission line
- Generator/synchronous condenser
- Transformer
- Shunt Reactive device (capacitor or reactor)

Given the configuration of the terminal station equipment in many of the original 230 kV stations, loss of a bus section was known to cause loss of load and excluded from the list. With the Transmission Planning's requirement for new 230 kV and above stations being configured in breaker-and-one-half (ring buses as a minimum for four elements), all new 230 kV and above stations shall meet the requirement for no loss of load for loss of a bus.

With respect to ac transmission lines, loss of a double circuit tower would result in the loss of two transmission circuits as a single contingency. To avoid this condition on the Newfoundland and Labrador Interconnected System, it is required that double circuit transmission lines be limited to no more than five structures at terminal station entrances for right of way congestion purposes only.

With respect to HVdc transmission lines, the loss of a pole is considered as the single contingency event.

The single element loss for the Newfoundland and Labrador Interconnected System assumes the loss of:

- A Transmission line
- Double circuit transmission lines excluding double circuit lines extending no more than five structures from terminal station entrances
- A Generator
- A Synchronous Condenser
- A Transformer
- A Shunt Reactive device (capacitor or reactor)
- A Bus section
- One pole of an HVdc bipole system
- An entire monopolar HVdc system

The ability to withstand a single contingency means that the contingency will not result in a violation of the applicable voltage and MVA limits, or cause system instability. In addition, all firm load that was interrupted due to the contingency can be restored within a reasonable time by either switching action, system reconfiguration, repair of equipment or the installation of temporary/mobile equipment.

In order to demonstrate that the Newfoundland and Labrador Interconnected System is planned to meet the N-1 criteria, adequate power system studies will be completed. These studies will include the simulation of the loss of an element:

- Without a fault
- With a line-to-ground fault having due consideration for successful and unsuccessful single pole automatic reclosing
- With a three phase to ground fault

4.4 Voltage Limits for Normal and Contingency Conditions

The voltage limits for planning purposes are defined in terms of steady state and transient criteria.

4.4.1 Steady State Voltage Criteria

The steady state voltage levels shall be as follows:

- Pre-contingency limits: For normal operations all bus voltages shall be maintained between 95% and 105%

- Post-contingency limits: For contingency or emergency situations, bus voltages shall be maintained between 90% and 110%. Generator terminal voltages shall be maintained between 95% and 105% in contingency or emergency situations
- Minimum 230 kV bus voltage of 212 kV at Come By Chance Terminal Station

4.4.2 Transient Voltage Criteria

Post fault recovery voltages on the ac system shall be as follows:

- Transient under voltages following fault clearing should not drop below 70%
- The duration of the voltage below 80% following fault clearing should not exceed 20 cycles

When planning studies determine that pre- or post-contingency voltage limits are violated, mitigation plans must be developed. The mitigation plans must alleviate bus voltage violations at all voltage levels.

4.5 MVA Limits

The applicable MVA limits for the Newfoundland and Labrador Interconnected System are described in the NLSO Transmission Planning document "NLSO Facilities Rating Guide".

For planning purposes, the pre- and post-contingency MVA rating limits cannot be exceeded. When studying the post-contingency, there must be flexibility in the system to reduce equipment loading following the contingency to acceptable levels using a combination of:

- transformer OLTC movement
- changes in generation dispatch (i.e. start of stand by generation)
- changes in system configuration (i.e. opening of loops)
- non-firm export reductions
- non-firm load reductions

Note these measures must be considered as reasonable actions within the power system operational timeframe.

When planning studies determine that pre- and/or post-contingency MVA limits are violated, mitigation plans must be developed.

4.6 Acceptable Rapid Voltage Changes

Transmission lines and shunt reactive devices (shunt reactor, capacitor or filter bank) shall be specified such that voltage changes due to switching shall not exceed 2.5%.

Motor starting systems shall be specified in accordance with Table 3 (from IEC 61000-3-7), as provided below. This table shall also be applied in the event of special operating conditions where the switching of a transmission line or shunt reactive device will result in a voltage change exceeding 2.5%.

Indicative Planning Levels for Rapid Voltage Changes

Number of Changes, N	Δ V / V (%) for HV System	Δ V / V (%) for HV System
N ≤ 4 per day	5 – 6	3 – 5
N ≤ 2 per hour	4	3
2 < N ≤ 10 per hour	3	2.5

Voltage changes exceeding 5% are not permitted for high voltage (HV) systems where voltages exceed 35 kV and voltage changes exceeding 6% are not permitted for medium voltage (MV) systems where voltages range between 1 kV and 35 kV.

4.7 Loss of Maritime Link

With the Labrador – Island HVdc Link out of service, export on the Maritime Link to Nova Scotia shall be limited in order to avoid excessive over frequency and subsequent tripping of generation on the Island portion of the Newfoundland and Labrador Interconnected System.

4.8 Loss of Load

Consequential load loss is accepted for radial portions of the Newfoundland and Labrador Interconnected System when the contingency involves loss of an element within the radial system.

There shall be no Non-Consequential load loss for a single element contingency.

- In steady state removal of a generator, transformer (except single transformer station), transmission line (except radial transmission lines) or shunt reactive power element shall not result in over load of the remaining elements, overload of the remaining elements or loss of customer load.
- With the Labrador – Island HVdc Link out of service, load loss due to loss of a generator on the Island portion of the system is acceptable provided it is well controlled (i.e. Under Frequency Load Shedding).

4.9 Contingencies for Study

The NLSO Transmission Planning Department will maintain a list of contingencies for study purposes. This list of contingencies will include events that demonstrate the ability of the system to remain within acceptable voltage and MVA limits and to maintain system stability.

The existing contingency list includes:

- Tripping of a single transmission line, transformer, generator, synchronous condenser, shunt capacitor bank, shunt reactor or series compensation device without a fault
- Successful single pole reclosing on line to ground faults
- Unsuccessful single pole reclosing on line to ground faults
- Three phase faults except a three phase fault on, or near, the Bay d'Espoir 230 kV bus with tripping of a 230 kV transmission line
- Loss of the largest generator on line on the Island System with and without fault
- Line to ground or three phase fault with tripping of a synchronous condenser
- Fault and tripping of a series compensated 230 kV transmission line with the series compensation device out of service on the in service parallel 230 kV transmission line
- Temporary pole fault on HVdc system
- Permanent pole fault on HVdc system
- Temporary bipole fault on HVdc system

4.9.1 Transmission Line Contingencies

Where there are parallel lines between stations, the study need only simulate the fault and subsequent tripping of one line. The selection of the line to be faulted and tripped is based upon the line rating, impedance and clearing times.

If the parallel lines have different line ratings, the line with the higher MVA rating is tripped.

If the parallel lines have different impedances, the line with the lower impedance is faulted and tripped.

If the parallel lines have difference fault clearing times, the line with the slower clearing time, or longer reclosing time is faulted and tripped.

4.9.2 Transformer Contingencies

Transformer outages must be treated differently than outages to other transmission equipment given the long lead times for repair and/or replacement.

Transformer additions at 138/66 kV, 66/25-12.5 kV terminal stations with one transformer per voltage class shall be planned on the basis of being able to install the Hydro mobile transformer or one of Newfoundland Power's mobile transformers under agreement between the two parties with respect to use of mobile transformer equipment. These transformers are generally located on radial portions of the system.

Transformer additions at all major (≥230 kV) terminal stations (i.e. two or more transformers per voltage class) shall be planned on the basis of being able to withstand the loss of the largest unit (i.e. installed spare transformer capacity) such that all firm loads can be supplied during system peak.

Generally the 230/138 kV and 230/66 kV transformers supply local networks or radial systems. Historically the terminal station design has been that multiple transformers are connected to a common 230 kV bus with no individual 230 kV circuit breakers (a cost vs. reliability decision). For these stations[1] a transformer fault will result in tripping of the 230 kV bus with consequential load loss within the local network or radial system. Following isolation of the faulted transformer, the load is restored utilizing the remaining transformer capacity in the station(s).

New 230/138 kV and 230/66 kV stations shall be designed such that a transformer fault or bus fault does not result in temporary loss of load.

Generally 315 kV and 735 kV transformers are connected to the PTS. As a result, fault of a 315 kV or 735 kV rated transformer shall not result in loss of load or overload of the remaining installed transformer capacity during system peak. In addition, a spare single phase unit is required for three phase banks comprised of single phase units at the 315 kV and 735 kV level. Existing spare 315 kV and 735 kV transformers include:

- $\frac{230}{\sqrt{3}}/\frac{735}{\sqrt{3}}/13.8$ kV, 333 MVA at Churchill Falls
- $\frac{315}{\sqrt{3}}/\frac{735}{\sqrt{3}}/13.8$ kV, 280/333 MVA at Churchill Falls Terminal Station 2
- Installed spare capacity 315/138/25 kV, 75/100/125 MVA at Muskrat Falls

Similarly, a spare single phase unit is required for three phase shunt reactor banks comprised of single phase units at 315 kV and 735 kV. Existing spare single phase shunt reactors include:

- 735/√3, 55 MVAR at Churchill Falls

[1] Massey Drive 230/66 kV, Stony Brook 230/138 kV, Bay d'Espoir 230/69 kV, Sunnyside 230/138 kV, Western Avalon 230/138 kV 230/66 kV, Hardwoods 230/66 kV and Oxen Pond 230/66 kV

Given the time frames for transformer repair and/or replacement generator step up transformer capacity, for PTS, generators shall be planned on the basis that there is a spare generator step-up transformer. Existing spare generator step-up transformers include:

- a spare 230/13.8 kV, 110 MVA generator step-up transformer for hydro-electric generators
- a spare 230/16 kV, 170 MVA generator step-up transformer for Holyrood thermal
- a spare 230/25/15 kV, 200 MVA synchronous condenser step-up transformer for Soldiers Pond Synchronous Condenser plant
- a spare 15/315 kV, 217 MVA generator step-up transformer for Muskrat Falls
- a spare 15/230 kV, 530 MVA generator step-up transformer at Churchill Falls
- a spare converter transformer at each of Muskrat Falls and Soldiers Pond converter stations

4.10 Short Circuit Levels

The planned maximum short circuit levels shall not exceed the interrupting capability of any associated circuit breakers. When short circuit review indicates that the short circuit level will exceed the interrupting rating of a circuit breaker(s), a mitigation plan shall be developed to replace the identified circuit breaker(s) prior to the system addition/modification resulting in the increased short circuit level being placed in service.

4.11 Dynamic Stability

Stability of the Newfoundland and Labrador Interconnected System shall be maintained in normal pre-contingency operation, during a contingency and post-contingency for all applicable contingencies with due regard to single pole and/or three pole reclosing and any automatic control actions.

The proper timing sequences which occur as a result of protection settings and telecommunication propagation times must be modelled for each event.

Stability of the system will be considered acceptable if all oscillations in voltage, current and angle are adequately damped so as not to cause unplanned equipment tripping or equipment damage. Generator pole slipping is unacceptable.

4.12 Performance Requirements

This section provides the performance requirements for the Newfoundland and Labrador Interconnected System.

4.12.1 Steady State and Dynamic Performance

- The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
- Consequential Load Loss as well as generation loss is acceptable as a consequence of any event except pre-contingency normal operation.
- Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
- Simulate Normal Clearing.
- Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.
- Analyses shall be performed with one high inertia synchronous condenser at Soldiers Pond out of service.

4.12.2 Steady State Only Performance

- Applicable Facility Ratings shall not be exceeded.
- System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits.
- The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.
- There shall be no interruption of firm transmission service, nor shall there be Non-Consequential load loss in the pre-contingency normal operation state.

4.12.3 Dynamics Only Performance

- System response shall be stable and clearly demonstrate positive damping within 30 seconds of the initiating event/contingency following a disturbance.
- Transient voltage response shall be within acceptable limits
- Post fault system frequencies shall be limited as follows:
  - Prior to High-Power Operation of the Labrador – Island HVdc link (LIL), post fault system frequencies shall not drop below 58 Hz and shall not rise above 62 Hz
  - With the LIL bipole in service for High-Power Operation, post fault system frequencies shall not drop below 59 Hz on the Island portion of the system
- Prior to High-Power Operation of the LIL, under frequency load shedding on the Island portion

of the system shall be permitted, but controlled, for:
  - loss of generation
  - loss of an ML pole
  - loss of the ML bipole
  - loss of the a LIL pole
  - loss of the LIL bipole
- With the LIL bipole in service for High-Power Operation, under frequency load shedding on the Island portion of the system shall be limited as follows:
  - shall not occur when both HVdc links are in service. Load loss shall be scheduled and controlled if the HVdc links are out of service
  - shall not occur for permanent loss of an HVdc pole
  - shall not occur for a temporary HVdc bipole outage
  - shall be controlled for a permanent HVdc bipole outage
- There shall be no commutation failures of an HVdc link during post fault recovery.
- To ensure reliable operation of Holyrood units, HVdc exports shall be limited such that the post-contingency generating output of each unit is within 15 MW of the pre-contingency output within 20 seconds
- There shall be no interruption of firm transmission service or Non-Consequential load loss for a three phase fault on either of the following PTS elements:
  - Generator
  - Transmission line
  - Transformer
  - Shunt reactor, capacitor, harmonic filter, FATCS device
  - Synchronous condenser
- With the LIL bipole in service for High-Power Operation, a single pole fault on the Labrador-Island HVdc Link shall not result in Non-Consequential load loss. Runback/curtailment of the Nova Scotia Block on the Maritime Link is acceptable for loss of a LIL pole under agreement between Emera and Nalcor.
- Opening of a NL BES transmission line without a fault shall not result in the interruption of firm transmission service or Non-Consequential load loss.
- A single line to ground fault on a PTS bus section:
  - Shall not result in interruption of firm transmission service or Non-Consequential load loss for EHV buses
  - May result in interruption of firm transmission service or Non-Consequential load loss for HV buses
- A single line to ground internal circuit breaker fault on a PTS circuit breaker may result in interruption of firm transmission service or Non-Consequential load loss.
- A single line to ground fault on a PTS element followed by a stuck breaker (breaker failure) may result in interruption of firm transmission service or Non-Consequential load loss.

5 Reference Documents

1. TP-S-001 NLSO Standard – Transmission Facilities Rating Guide

Document Summary

Document Owner:	Transmission Planning
Document Distribution:	NLSO

Revision History

Revision	Prepared by	Reason for change	Effective Date
1	P. Thomas	Approved for Release	2017/11/28
2	R. Collett	Clarification of acceptable voltage change for switching of reactive power elements	2018/05/11
3	R. Collett	Clarification of steady state voltage requirements for generator terminal buses	2019/03/07
4	R. Collett	Clarification of rapid voltage changes.	2020/04/13
5	R. Collett	Update to requirements for spare step-up transformers	2020/09/14
6	R. Collett	Removed definitions and abbreviations section.	2020/10/02

Document Approvers

Position	Signature	Approval Date
Manager, Transmission Planning	R. Collett	2020/10/02

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