Schedule B

Q. **(Schedule B, page 9 of 12) Net Metering Service Option (for Rates #1.1, #1.1S, #2.1, #2.3 and #2.4 only)**

a) How many customers have availed of this optional rate in each year since introduced in 2017, what generation technology have they used, and what is the total amount of generation demand and energy displaced by these customers in each year?

b) Please describe Newfoundland Power's marketing programs used to promote this optional rate.

c) Please explain how Newfoundland Power incorporates net metering service in its transmission and distribution planning process.

d) What is the basis for the banked energy credit, when was it last updated and what was the reason for the update?

e) How does the banked energy credit compare to the system marginal value of energy?

f) What are the primary constraints and reasons why more customers have not availed of this option and what has Newfoundland Power done to mitigate the constraints?

g) If Newfoundland Power were directed by the Board to update this option to better reflect current estimates of marginal costs, what would Newfoundland Power propose?

A. a) Newfoundland Power's first net metering customer was connected in 2018. A summary of annual customer connections for the 2018-2023 period is provided in Table 1.

Table 1:
Annual Net Metering Summary
2018 – 2023

Year	# of New Customers[1]	Technology Type	Installed Capacity [kW]	Energy Delivered to NP [kWh]
2023	14	Solar	170.6	123,506
2022	7	Solar	93.2	90,508
2021	10	Solar	114.6	47,270
2020	3	Solar	17.5	35,963
2019	5	Solar & Wind	40.8	29,813
2018	3	Solar & Wind	37.2	14,760
Total	**42**	**Solar & Wind**	**473.9**	**341,820**

[1] A 2020 net metering customer completed two additional capacity expansion projects to their service address in 2021 and 2023, which are reflected in the "Installed Capacity" column in Table 1 for those years. Including these two additional capacity expansion projects, there have been a total of 44 installed net metering projects since 2018.

b) Newfoundland Power provides comprehensive information related to its Net Metering Service Option on its website.[2] The website contains important information for potential Net Metering Service Option customers including: how net metering works; how to get connected; a fact sheet; connection requirements including a sample net metering interconnection agreement; and answers to frequently asked questions ("FAQs").

c) See Attachment A, which provides Newfoundland Power's *Distribution Planning Guidelines*. These guidelines contain information on the Company's system planning criteria, and includes information regarding net metering requirements.

d) Banked energy credits are the amount of kWh energy supplied by the customer to Newfoundland Power that exceeds the kWh energy supplied by the Company to the customer. Banked energy credits can be carried forward from month to month. The balance of the customer's banked energy credits carried forward are settled annually by means of a credit on the customer's bill.[3]

The annual settlement of banked energy credits is based upon Hydro's 2nd block energy charge of 18.165 ¢/kWh to Newfoundland Power. Effectively, customer-produced energy reduces the amount of energy Newfoundland Power must purchase from Hydro. This was considered to be a reasonable approach by the Board in its Order approving the Net Metering Service Option.[4] The energy charge upon which the annual settlement of banked energy credits is determined was most recently established upon the conclusion of Hydro's *2017 General Rate Application*.[5]

e) See Attachment B.

f) In its order approving Newfoundland Power's Net Metering Service Option, the Board stated that it must be satisfied that the proposed net metering program: (i) is consistent with sound public utility practice; (ii) permits the management of all sources and facilities for the production, transmission and distribution of power in the province consistent with the least cost delivery of service to customers; and (iii) is reasonable and not unjustly discriminatory. The Board further stated that adherence to these legislative requirements requires that the Board establish that Newfoundland Power's net metering program is fair to both participating and non-participating customers and is consistent with the least cost delivery of service in the province.[6]

Newfoundland Power's Net Metering Service Option provides customers with the opportunity to generate their own electricity through renewable generation alternatives and to reduce their energy charges from Newfoundland Power. The

---

2 See https://www.newfoundlandpower.com/en/My-Account/Usage/Electricity-Rates/Net-Metering.
3 See Newfoundland Power's *Schedule of Rates, Rules and Regulations, Effective July 1, 2023*, page 30. The Net Metering Service Option was originally approved by the Board in Order No. P.U. 17 (2017).
4 See Order No. P.U. 17 (2017) page 5, lines 33-45.
5 In Order No. P.U. 30 (2019), the Board approved a new Utility Rate charged by Hydro to Newfoundland Power. The 2nd block energy charge applicable to the Utility Rate was set at 18.165 ¢/kWh.
6 See Order No. P.U. 17 (2017), page 5, lines 13-25.

challenge of generating energy at a cost that is less than the energy that can be provided from the grid is a key constraint for customers.[7]

g) See part e) of the response to Request for Information CA-NP-110.

[7] See Canada Energy Regulator Article: *Market Snapshot: Residential solar is financially viable in some provinces and territories, but not in others*, Release date 2018-12-06.

Newfoundland Power Inc.
Distribution Planning Guidelines

DISTRIBUTION PLANNING GUIDELINES

January 2021

Table of Contents

1.0 INTRODUCTION

1.1 Background

The Distribution Planning Guidelines are intended to be a complete listing of all the criteria that must be met when planning a distribution system as well as the guidelines that are useful in planning the most economical expansion of the distribution system.

1.2 Scope

This document outlines the guidelines used in the development of the distribution system with voltage levels 25kV and below. These guidelines present information on Newfoundland Power's planning criteria, distribution automation philosophy, and net metering requirements. This is intended to be a reference document that system planning and regional engineering can use for distribution planning.

This document presents Newfoundland Power's technical criteria, developed to maintain safe, reliable service to customers. Some criteria, such as power quality and reliability, are presented as targets which may be used in conjunction with other criteria to make expenditure decisions.

The criteria outlined in this document will help develop and maintain uniform design practices across all areas of the business.

2.0 PLANNING CRITERIA

2.1 Steady State Voltage Criteria

2.1.1 Introduction

This planning criteria covers the application of minimum and maximum voltage levels on the distribution system. This document specifies the minimum and maximum voltage levels under steady state conditions used to plan the distribution system.

2.1.2 Criteria

Distribution feeders are designed to ensure that customers have acceptable voltage at their utilization point. Corrective action will be taken when the predicted loading on the distribution feeder model indicates that the primary voltage (three phase and/or single phase) is outside of the minimum or maximum voltage parameters stated in Table 1:

Table 1: Steady State Planning Voltage Criteria

(on a 120V base)	Minimum	Maximum
Normal Distribution Feeder Voltage	116 V	127 V
Extreme Distribution Feeder Voltage	112 V	129 V

The system neutral voltage will be limited to a maximum of 10 V. In rural areas it may be more difficult to accomplish this level because of the system design (i.e. long single phase taps and/or rocky terrain). Priority to meet the 10 V limit will be given to those areas where there are verifiable concerns with respect to safety or interference with adjacent communications circuits.

A maximum of three voltage regulating devices may be installed in series on a distribution feeder. This includes any OLTC located at the substation. It is recognized that from an operational perspective, more than three regulators may be operated in series, however this is not desirable in the long term.

The need for voltage support is assessed to ensure that customers have acceptable voltage at their utilization point based on the CSA Standard C235: "Preferred Voltage Levels for AC systems up to 50 000 V". This standard outlines the recommended steady state voltage variation limits for circuits up to 1000 V at the utilization point as per Table 2, based on CSA C235:

Table 2: CSA Preferred Voltages Levels at Utilization Point

	Extreme Operating Conditions				
		Normal Operating Conditions			
Single Phase	104 V	108 V	-	125 V	127 V
Three Phase	108 V	110 V	-	125 V	127 V

Voltage improvements will be initiated when the voltage reaches or is projected to reach below the minimum recommended voltage under normal operating conditions.

Corrective action is also initiated for instances where the voltage is or is expected to be in excess of the maximum recommended levels under normal operating conditions.

Some extreme operating conditions are temporary in nature. So the decision to initiate system improvements will depend on factors such as location, customer type and the extent to which limits are exceeded (i.e., magnitude and duration reflecting safety concerns as well as the probability of equipment damage).

2.1.3 System Voltage Limits

Recognizing that the specified CSA voltage limits apply at the utilization point, some allowance must be made for the voltage reduction through the service transformer as well as the secondary and internal wiring voltage drop to the utilization points.

Generally, a 3 – 5 V drop from the main line to the customer utilization point under peak loading conditions and a 1 – 2 V drop under light load are assumed. In order to comply with CSA limits, the distribution feeder will be modelled in distribution system analysis software and corrective action will be taken when the primary voltage calculated from the peak load model indicates an existing or projected steady state voltage of less than 116V under normal conditions and/or less than 112V under extreme conditions. Similarly, corrective action will be taken when the primary voltage of a light load feeder model indicates an existing or projected steady state voltage of 127 V (120 V base) or more under normal conditions and/or more than 129V under extreme conditions.

2.2 Power Quality

2.2.1 Voltage Unbalance

Load unbalance on a feeder or service may result in undesirable voltage unbalance. Voltage unbalance should not exceed 5% of the nominal voltage.

2.2.2 Frequency

A frequency tolerance of 0.5 Hz is considered the industry standard in North America. However in Newfoundland frequency may vary 1.0 Hz. Newfoundland and Labrador Hydro's under frequency load shedding scheme starts to drop load at 58.8 Hz to maintain the system frequency.

2.2.3 Harmonics

Harmonics are produced by non-linear loads applied to the system, which draw current in abrupt short pulses. The total harmonic distortion shall not exceed 5% of the fundamental and no one harmonic shall exceed 1.5% of the fundamental.

2.2.4 Voltage Flicker

The fluctuation of voltage flicker on the system caused by situations such as motor starting should not exceed more than 3% of the normal operating voltage.

2.3 Reliability

Each year the Company identifies its worst performing feeders on the basis of System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Hours of Interruption per Kilometre (CHIKM), and Customers Interrupted per Kilometre (CIKM). These performance indices are used to rank worst-performing feeders that require further analysis of reliability data and engineering assessment.

2.3.1 System Average Interruption Frequency Index (SAIFI)

This index is the average number of interruptions per customer served per year. It is determined by dividing the accumulated number of customer interruptions in a year by the number of customers served. A customer interruption is "one interruption to one customer". Mathematically SAIFI is given by:

$$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customer Served}}$$

2.3.2 System Average Interruption Duration Index (SAIDI)

This index is the average interruption duration for customers served during a year. It is determined by dividing the sum of all customer interruption durations in a year by the number of customer served during the year. Mathematically SAIDI is given by:

$$\text{SAIDI} = \frac{\text{Sum of Customer Interruption Durations}}{\text{Total Number of Customer Served}}$$

2.3.3 Customers Interrupted per Kilometre (CIKM)

This index is the total number of customer that have experienced an outage per kilometre of line. It is determined by dividing the sum of all the customers that have experienced an outage by the length of the line in kilometres.

$$\text{CIKM} = \frac{\text{Sum of Customers Experienced an Outage}}{\text{Total Length of Line (km)}}$$

2.3.4 Customer Hours of Interruption per Kilometre (CHIKM)

This index is the total number of customer-outage-hours per kilometre of line. It is determined by dividing the sum of all the customer-outage-hours by the length of the line in kilometres.

$$\text{CHIKM} = \frac{\text{Sum of Customer-Outage-Hours}}{\text{Total Length of Line (km)}}$$

2.4 Cold Load Pick Up

Cold Load Pick Up (CLPU) is excessive current experienced upon circuit re-energization. The excessive current is caused by the following two phenomena, both of which are likely to occur:

1. Inrush current associated with motor starting, transformers, etc. Although the magnitudes are quite large - in the order of 6 to 25 times the normal current - the duration is quite short, a matter of several cycles.

2. An increase in the post-interruption load value relative to the pre-interruption load value due to the loss of diversity of cycling loads (electric heating, air conditioners, etc.). The ratio of the post-interruption load to pre-interruption load varies with the length and time of day of the interruption.

$$\text{CLPU} = \frac{\text{CLPU Load}}{\text{Normal Winter Peak Load}}$$

If the maximum CLPU on a feeder is unknown, the CLPU factor is assumed to be 2.0 and the duration is assumed to be 45 minutes.

2.5 Main Feeder Sectionalizing Points

The planning ampacity of overhead conductor can be increased significantly if sectionalizing is available to limit the amount of load present during the CLPU contingency. Although sectionalizing is a means of deferring substantial costs, it decreases the reliability of the feeder in terms of SAIDI because customers are subjected to longer outages. For this reason, only one designated sectionalizing switch may be permitted per feeder. The sectionalizing switch shall be located such that it maximizes the planning ampacity of the feeder.

$$\text{Sectionalizing Factor} = \text{Fraction of Load in First Section} \times \text{CLPU Factor}$$

For example, if a sectionalizing switch were installed on the feeder where 66.67% of the load was located on the first section of the feeder, the sectionalizing factor would be calculated as follows:

$$\text{Sectionalizing Factor} = 0.6667 \times 2.0 = 1.33$$

2.6 Overhead Conductor and Underground Cable Ampacity Criteria

2.6.1 Introduction

This section covers the planning criteria for the application of ampacity levels for overhead conductors and underground cable used in the distribution system. This section specifies the maximum ampacity levels used to plan the distribution system.

During operations, different ampacity ratings may be used taking into account the actual temperatures, wind speed, pre-loading and duration of the loading at the time. Operating equipment at higher ampacity levels may reduce the life of the equipment in order to supply load.

2.6.2 Planning Criteria

Distribution feeders are designed to ensure that the equipment on the distribution system has the capability to supply customer load for forecast load conditions without any loss of equipment life.

All single phase and two phase taps that exceed 85A per phase should be upgraded by extending an additional phase, as to not cause the main truck feeder to trip in the event of a loss supply to that tap.

This document outlines the ampacity ratings for overhead conductors, underground cables, and the maximum feeder loading used by Planning in the distribution system.

2.6.3 Overhead Conductor

Distribution feeders are modelled to ensure that the overhead conductors are not loaded above their planning ratings. Corrective action will be taken when the model of the distribution feeder indicates that any equipment will be operated above its rating under the forecast peak load conditions.

Table 3: Overhead Conductor Ampacity Limits

Overhead Conductor Ampacity Ratings										
Conductor Type	Cont. Winter Ampacity (Amps)	Cont. Summer Ampacity (Amps)	Planning Ratings No Sectionalizing CLPU Factor = 2.0[1] Sectionalizing Factor = 2.0[2]				Planning Ratings Optimal Sectionalizing CLPU Factor = 2.0 Sectionalizing Factor = 1.33			
			Amps	MVA			Amps	MVA		
				4.16	12.5	25.0		4.16	12.5	25.0
1/0 AASC	303	249	152	1.1	3.3	6.6	228	1.6	4.9	9.8
4/0 AASC	474	390	237	1.7	5.1	10.2	356	2.6	7.7	15.4
477 ASC	785	646	393	2.8	8.5	17.0	590	4.2	12.7	25.5
#2 ACSR	224	184	112	0.8	2.4	4.8	168	1.2	3.6	7.3
2/0 ACSR	353	290	177	1.3	3.8	7.6	265	1.9	5.7	11.4
266 ACSR	551	454	276	2.0	6.0	11.9	414	3.0	8.9	17.9
397 ACSR	712	587	356	2.6	7.7	15.4	535	3.9	11.6	23.1
#6 Cu	175	125	88	0.6	1.9	3.8	132	0.9	2.9	5.7
#4 Cu	203	166	102	0.7	2.2	4.4	153	1.1	3.3	6.6
1/0 Cu	376	309	188	1.4	4.1	8.1	283	2.0	6.1	12.2
2/0 Cu	437	359	219	1.6	4.7	9.5	329	2.4	7.1	14.2

The winter ampacity is the maximum allowable amperage on an aerial conductor under any circumstances during winter. This ampacity is based on relatively conservative, industry accepted standards:

75°C conductor temperature
0°C ambient air temperature
2 ft/s wind speed
100% load factor
9" minimum separation phase to neutral

Note: With these parameters the maximum span length is 175 feet for the ampacities in Table 3.

2.6.4 Underground Cable

Distribution feeders are modelled to ensure that the underground cables are not loaded above their ratings. Corrective action will be taken when the model of the distribution feeder indicates that any equipment will be operated above their rating under the forecast peak load conditions.

1 Refer to Section 2.4 for further details regarding Cold Load Pick Up (CLPU).
2 Refer to Section 2.5 for further details regarding Feeder Sectionalizing Points.

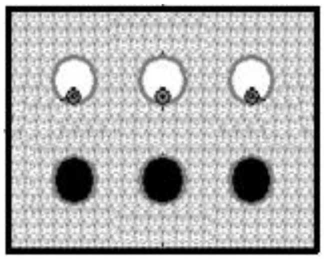
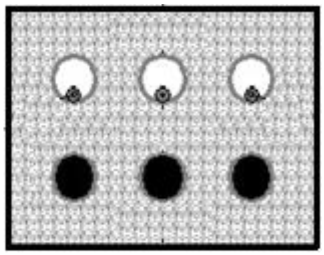
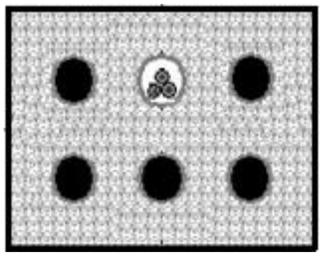
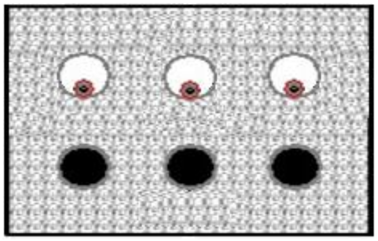
Table 4 outlines the manufacturer specifications for standard underground cable required for analysis in underground cable ampacity software.

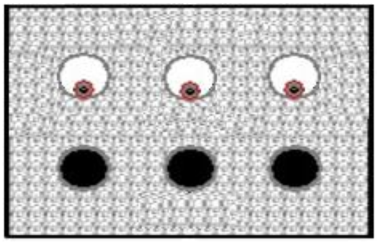
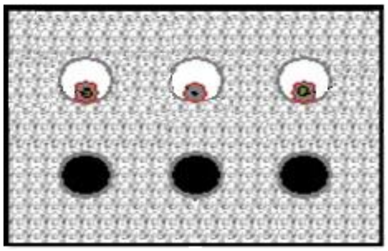
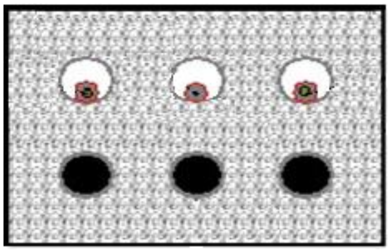
Table 4: Underground Cable Software Parameters

Cable Size		1/0		500 MCM	750 MCM	1000 MCM
Voltage kV (Ph-Ph)		15	25	15	15	28
Conductor	Material	Al	Al	Cu	Cu	Al
	Construction	Solid	Solid	Strand	Strand	Strand
	Diameter (in)	0.325	1.325	0.736	0.908	1.060
Conductor Shield	Thickness (in)	0.018	0.018		0.026	0.026
	Diameter (in)	0.361	0.361	0.7838	0.960	1.112
Insulation	Insulation Type	TRXLPE	TRXLPE	TRXLPE	TRXLPE	TRXLPE
	Thickness (in)	0.175	0.260	0.175	0.175	0.280
	Diameter (in)	0.711	0.881	1.154	1.310	1.672
	Max. Conductor Temp	90°C	90°C	90°C	90°C	90°C
	Max. Emergency Temp	130°C	130°C	130°C	130°C	130°C
Insulation Shield	Material	Semi-conductor	Semi-conductor	SC XLPO	SC XLPO	Semi-conductor
	Thickness (in)	0.035	0.035	0.047	0.045	0.060
	Diameter (in)	0.781	0.951	1.237	1.400	1.792
Concentric Neutral	Material	Cu	Cu	Cu	Cu	Cu
	Construction	Round Wire	Round Wire	Round Wire	Round Wire	Round Wire
	Diameter (in)	0.897	1.067	1.399	1.592	1.942
Jacket	Material	Poly-ethylene	Poly-ethylene	Poly-ethylene	Poly-ethylene	Poly-ethylene
	Thickness (in)	0.055	0.055	0.080	0.080	0.080
	Diameter (in)	1.007	1.177	1.505	1.752	2.102

Typical duct bank configurations and associated ampacitys can be found in Table 5.

Table 5: Underground Cable Duct Bank Configurations

Cable Size	Duct Bank Configuration	Ampacity
15kV 500MCM Cu Concentric Neutral		472 A
15kV 500MCM Cu Separate Neutral		662.5 A
15kV 500MCM Cu Separate Neutral *(3 Cables, 1 Duct)*		514.6 A
15kV 750MCM Cu Concentric Neutral		527.6 A

15kV 750MCM Cu Separate Neutral		810.9 A
28kV 1000MCM Al Concentric Neutral		554.1 A
28kV 1000MCM Al Separate Neutral		741.2 A

The ampacity is the maximum allowable amperage on an underground cable under any circumstances. This ampacity is based on the following parameters:

5 °C ambient soil temperature
0.9 °C.m/W thermal resistivity of native soil
0.6 °C.m/W thermal resistivity of the duct bank

2.7 Distribution Equipment Ampacity Criteria

2.7.1 Circuit Breakers

Table 6 outlines the minimum equipment requirements for Newfoundland Power distribution feeder circuit breakers.

This information should be field verified to confirm actual equipment ratings prior to completing any associated work.

Table 6: Typical Breaker Ratings

Description	
Nominal System Voltage (kV)	12.5 / 25
Rated Operating Voltage (kV)	15 / 27.5
Nominal Frequency (Hz)	60
Rated Continuous Current (A)	1200
Minimum Interrupting Current Rating at 12.5kV (kA)	25
Minimum Interrupting Current Rating at 25kV (kA)	25

2.7.2 Reclosers

Table 7 outlines the minimum equipment requirements for Newfoundland Power substation and downline reclosers.

This information should be field verified to confirm actual equipment ratings prior to completing any associated work.

Table 7: Typical Recloser Ratings

Description	
Nominal System Voltage (kV RMS)	14.4 / 25
Rated Maximum Design Voltage (kV RMS)	17 / 29
Nominal Frequency (Hz)	60
Continuous Current (A RMS)	800
Interrupting Current (kA RMS Symmetrical)	12.5

2.7.3 Fuses

The standard fuse link at Newfoundland Power for distribution branch lines and pole mount distribution transformers is Type K.

Type K fuse links are designed to carry 150% of their rated current without damage to the fuse link, and will start to melt at 200% of their rated current. This capacity is for special loading situations, such as short-time overloads and cold load pick up.

2.7.4 Transformers

The thermal loading limits of transformers (includes substation transformers, voltage regulators and step-down transformers) shall be loaded to 130% of its nameplate rating under normal operating conditions and to 160% of nameplate rating during emergency conditions. The increased loadings take into account the winter peaking bonus when temperatures are below the 40°C nameplate rating. Refer to the *Transformer Loading Guidelines* for detailed information regarding transformer loading.

The planning ampacity of transformers shall be the 40°C nameplate rating. By restricting normal transformer loads to the nameplate rating, the 160% overload capability provides capacity to restore service after an extended outage when extreme CLPU may be present.

For substations that contain only one feeder and where CLPU may exceed 160% of the normal winter peak load, a sectionalizing switch shall be installed on the feeder to limit CLPU. Where substations contain two or more feeders and a CLPU potential greater than 160% of transformer nameplate rating exists, in addition to sectionalizing, feeders shall be restored on a sequential basis to limit CLPU.

3.0 DISTRIBUTION AUTOMATION

3.1 Introduction

This section outlines the typical locations of downline reclosers to provide more flexibility in the operation of the distribution system. Distribution automation is implemented to decrease customer outage minutes, improve service restoration capability for customers, and address cold load pick up issues. These devices have the capability to automatically sectionalize a faulted feeder to maintain power to customers upstream of the fault.

Device locations and configurations are dependent upon various feeder characteristics such as the number of customers, feeder load and geographic area.

3.2 Scenario 1: Single Automated Downline Recloser

The location of a single downline recloser is typically installed such that ⅔ of the customer load is between the substation and the downline recloser. Device locations can also be influenced by the geographic area and overall feeder length.

Figure 1 illustrates a typical schematic for the installation of a single automated downline recloser. In this scenario, if a fault were to occur downstream of R2, R2 would operate and lock out, resulting in avoidance of an outage to the customers between the substation and R2.

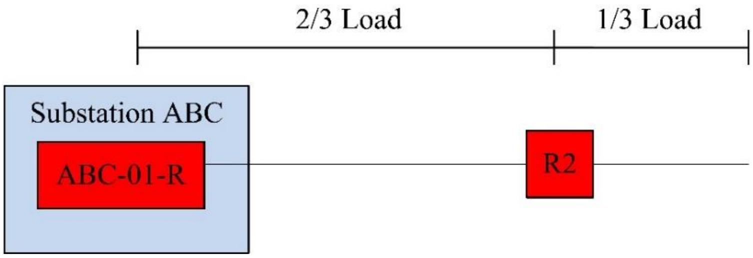


Figure 1: Single Automated Downline Recloser

This device configuration and installation is an optimal solution for the majority of distribution feeders.

3.3 Scenario 2: Multiple Automated Downline Reclosers

The location of multiple downline reclosers is typically installed such that:

(i) ⅓ of the customer load is between the substation and the first downline recloser;
(ii) ⅓ of the customer load is between the first and second downline recloser; and
(iii) ⅓ of the customer load is downstream of the second downline recloser.

Figure 2 illustrates a typical schematic for the installation of multiple automated downline reclosers on a feeder. The installation of multiple reclosers provides additional automatic sectionalizing points downstream of the substation.

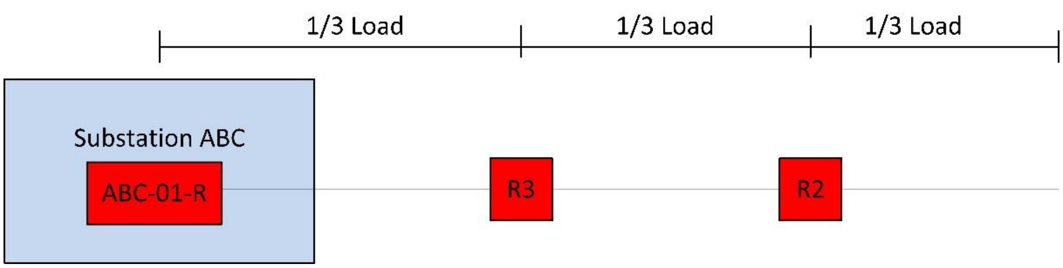


Figure 2: Multiple Automated Downline Reclosers

In this scenario, if a fault were to occur between R3 and R2, R3 would operate and lock out, resulting in avoidance of an outage to the customers between the substation and R3.

If a fault were to occur downstream of R2, the system would operate similar to Scenario 1, where R2 would operate and lock out, resulting in avoidance of an outage to the customers between the substation and R2.

The installation of multiple downline reclosers is an optimal solution for:

(i) long rural feeders; and
(ii) heavily loaded urban feeders.

3.4 Scenario 3: Automated Downline Recloser Feeder Tie

The installation of automated devices at normally open tie locations provides an automatic transfer point between two feeders.

Figure 3 illustrates a typical schematic for the automation of a normally open switch used to tie 2 feeders together.

If a fault were to occur between the substation and downline recloser on either feeder, the substation recloser would operate and lock out. Customers between the downline recloser and tie point ("TR") can be restored following operation of the downline recloser and tie recloser, allowing customers to be transferred onto the adjacent feeder.

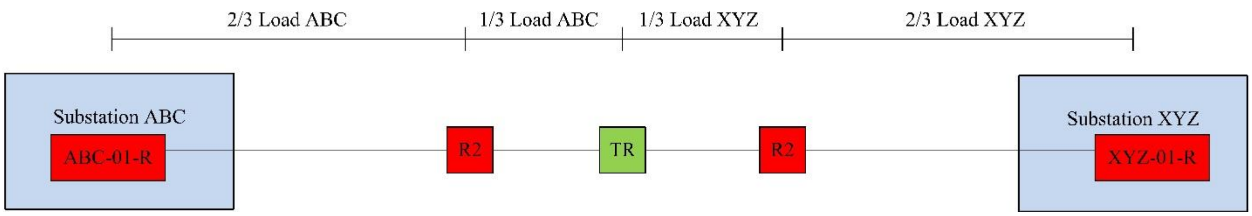


Figure 3: Automated Downline Recloser Feeder Tie

Normally open tie switches are automated in specialized cases only. To automate a tie point between 2 feeders, the following conditions must apply:

(i) at least 1 of the feeders must have a downline recloser installed on it;
(ii) the feeders must be of the same voltage;
(iii) each feeder must have adequate capacity to support load from the adjacent feeder;
(iv) the substation transformer supplying each feeder must have adequate capacity; and
(v) protection settings of devices must coordinate under all feeder configurations.

Automating normally open tie points is an optimal solution in:

(i) high-density areas where the ability to transfer customers remotely to adjacent feeders has a significant impact on the number of customers that experience an outage; and
(ii) remote areas where the ability to transfer customers to adjacent feeders remotely would have a significant impact on the duration that the customers experience an outage.

4.0 NET METERING

4.1 Introduction

Net metering is a process of connecting customer renewable generation to a public utility power grid, and surplus power is transferred onto the grid, allowing customers to offset the cost of power drawn from the utility.

4.2 Planning Criteria

The maximum connected generation per customer is limited to 100kW, operated at 60Hz. Customer Facilities will be interconnected with radial distribution systems at nominal primary voltages of 25,000

VAC or less, and nominal secondary voltages of 600 VAC or less. Customer facilities shall be sized to not exceed the annual energy requirements of the buildings or facilities located on the Customer's Serviced Premises.

Customer facilities must be capable of operating within the extreme voltage level variation limits shown in Table 8.

Table 8: Normal Service Voltage Variation Limits

Nominal System Voltage	**Recommended Voltage Variation Limits for Circuits up to 1000 volts, Applicable at Service Entrance**			
	Extreme Operating Conditions			
		Normal Operating Conditions		
	Min	**Min**	**Max**	**Max**
Single Phase				
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	503	550	625	635
Three Phase 4-Conductor				
120/208Y	110/190	112/194	125/216	127/220
240/416Y	220/380	224/388	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				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

Customer applications are reviewed by the Transmission and Distribution Engineering department. Each application is modelled in distribution modelling software to evaluate the impact of additional generation to the power grid.

Installations must comply with the latest versions of the CEC Part 1, CSA C22.3 No. 9 - Interconnection of Distributed Resources and Electricity Supply Systems, and CSA C22.2 No. 257 - Interconnecting Inverter-based Micro-distributed Resources to Distribution Systems.

The maximum aggregate cap for total net metering on the provincial system, between Newfoundland Power and Newfoundland Hydro is 5MW.

For additional information regarding Newfoundland Power's Net Metering Program, refer to the Net Metering Interconnection Requirements document.

Newfoundland Power Inc.
Net Metering Service Option - Banked Energy Credits
And Marginal Energy Supply Cost

Newfoundland Power Inc.
Net Metering Service Option Banked Energy Credits and
Marginal Energy Supply Cost (2025F)

Banked Energy Credits	Marginal Energy Supply Costs				
	Winter		Summer	Winter	Annual
All hours ¢/kWh	On-Peak ¢/kWh	Off-Peak ¢/kWh	All-Hours ¢/kWh	All-Hours ¢/kWh	All-Hours ¢/kWh
18.165	12.240	10.338	2.995	11.193	5.712

Notes:

1. Net Metering Service Option banked energy credits per Newfoundland and Labrador Hydro's ("Hydro") Utility rate to Newfoundland Power. See Hydro's *Schedule of Rates, Rules and Regulations, Updated January 1, 2024*, page UT-4.
2. Marginal Energy Supply Cost is based on Newfoundland and Labrador Hydro's Marginal Cost Update, October 2023.
3. Winter season defined as December through March.
4. On Peak Hours Winter 7:00 a.m. to 10:00 p.m., Monday through Friday.
5. On Peak Hours Summer 8:00 a.m. to 10:00 p.m., Monday through Friday.