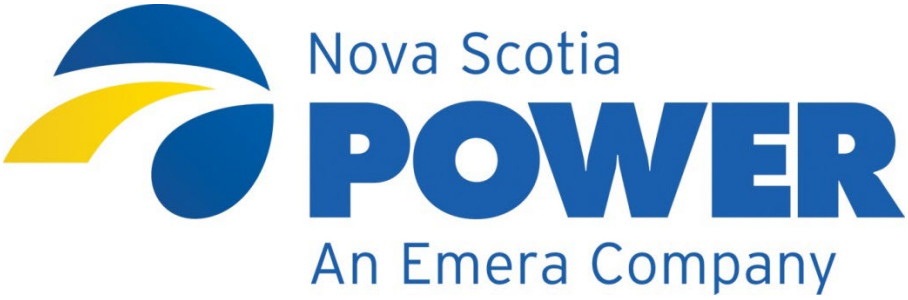

Tariffs

2025

Approved by the Nova Scotia Utility and Review Board pursuant to The Public Utilities Act, R.S.N.S., 189,c.380 as amended

For more information, call Nova Scotia Power at 1-800-428-6230 (902-428-6230 in Metro Halifax) www.nspower.ca

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View the complete Open Access Transmission Tariff on OASIS at:
http://oasis.nspower.ca/en/home/oasis/default.aspx

DOMESTIC SERVICE TARIFF
Rate Codes 02, 03, 04

CUSTOMER CHARGE

	Per month
Effective February 2, 2023	$19.17
Effective January 1, 2024	$19.17

ENERGY CHARGE

	Cents per kilowatt-hour
Effective February 2, 2023	15.744
Effective January 1, 2024	16.931

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be as follows:	**Per month**
Effective February 2, 2023	$19.17
Effective January 1, 2024	$19.17

AVAILABILITY:

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the domestic tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

Optional Green Power Rider

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing "blocks" of Green Power. For every block purchased, NSPI will provide 125 kWh per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer's normal bill for service taken under the Domestic Service rate.

Special Terms and Provisions

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

CUSTOMER CHARGE

CUSTOMER CHARGE

	Per month
Effective February 2, 2023	$19.17
Effective January 1, 2024	$19.17

ENERGY CHARGES

	December, January and February			
	7:00 am to 12:00 pm	12:00 pm to 4:00 pm	4:00 pm to 11:00 pm	11:00 pm to 7:00 am
	Cents per kilowatt-hour			
Effective February 2, 2023	21.377	16.799	21.377	9.522
Effective January 1, 2024	22.565	17.987	22.565	10.710

The above rates apply weekdays (Monday through Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate for 11:00 pm to 7:00 am.

	March to November	
	7:00 am to 11:00 pm	11:00 pm to 7:00 am
	Cents per kilowatt-hour	
Effective February 2, 2023	16.799	9.522
Effective January 1, 2024	17.987	10.710

The above rates apply weekdays (Monday through Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate for 11:00 pm to 7:00 am.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be as follows.

	Per month
Effective February 2, 2023	$19.17
Effective January 1, 2024	$19.17

AVAILABILITY:

This tariff is only available to customers employing electric-based heating systems utilizing Electric Thermal Storage (ETS) equipment, and electric in-floor radiant heating systems utilizing thermal storage and appropriate timing and controls approved by the Company.

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the Domestic Service Time Of Day Tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the Domestic Service Tariff.

CUSTOMER CHARGE

	Per month
Effective January 1, 2024	$19.17

ENERGY CHARGE

	During a Critical Peak Event	**Non-Critical Peak Hours**
	Cents per kilowatt-hour	
Effective January 1, 2024	142.256	14.290
Effective November 1, 2024	169.310	14.222

The Critical Peak Event is of a four-hour duration and can be called at any time between 6:00 AM and 11:00 PM, Monday to Sunday, during the Winter Period November 1 through March 31.

The Critical Peak Event pricing applies when a Critical Peak Event is called. In all other hours in the Winter Period, and for all hours in the Non-Winter Period, the rate shall be the Non-Critical Peak Hours Rate in the table above.

CRITICAL PEAK EVENT PROCEDURE

1. In the Winter Period, Critical Peak Events exclude all hours on the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, November 11, December 25 and December 26. If January 1, November 11, December 25 or 26 fall on a weekend, the Critical Peak Events also exclude the weekday the holiday is observed.
2. Critical Peak Events will be scheduled, at the sole discretion of NSPI, when NSPI is expecting conditions including, but not limited to, high energy (kWh) usage, high market energy costs, or generation or transmission outages.
3. When a Critical Peak Event is scheduled, subscribers to this tariff will be notified in advance and the Critical Peak Event Energy Charge (higher rate) will be in effect for all kWh consumed by the customer during the period. The notification is a signal to the customer to reduce the amount of electricity they are using.
4. Critical Peak Events will only be scheduled to occur during the Winter Period.
5. No more than 18 Critical Peak Events may be scheduled per Winter season (November through

March inclusive). No more than three Critical Peak Events will be scheduled per week (Monday to Sunday). No more than three Critical Peak Events per Winter season may be scheduled on a weekend.

6. Customers will be notified of a Critical Peak Event in advance. By 4:00 pm the day prior to the event, the Customer will receive a notification message. The Customer is responsible to watch for this message, and to notify NSPI in advance if their contact information changes.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be as follows.

	Per month
Effective January 1, 2024	$19.17

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) The customer must be on electronic billing and have a MyAccount profile.
d) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
e) The customer cannot be taking seasonal service from NSPI under Regulation 3.3.
f) The customer cannot be taking Net Metering service from NSPI under Regulation 3.6.

Optional Green Power Rider

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing "blocks" of Green Power. For every block purchased, NSPI will provide 125 kWh per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer's normal bill for service taken under the Domestic Service Critical Peak Pricing Tariff.

Special Terms and Provisions

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the Domestic Service Tariff.

CUSTOMER CHARGE

	Per month
Effective January 1, 2024	$19.17

ENERGY CHARGE

Non-winter Period April 1 through October 31	**Cents per kilowatt-hour**
	All hours
Effective January 1, 2024	11.719
Effective November 1, 2024	11.426

Winter Period November 1 through March 31	**On-peak (morning)**	**Off-peak**	**On-peak (evening)**	**Off-peak**
	7:00 am to 11:00 am	**11:00 am to 5:00 pm**	**5:00 pm to 9:00 pm**	**9:00 pm to 7:00 am**
	Cents per kilowatt-hour			
Effective January 1, 2024	32.120	16.931	32.120	16.931
Effective November 1, 2024	33.862	16.931	33.862	16.931

Note 1: In the Winter Period, the off-peak price also applies to all hours on Saturdays, Sundays, and the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, November 11, December 25 and December 26. If January 1, November 11, December 25 or 26 fall on a weekend, the off-peak price shall apply on the weekday the holiday is observed.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be as follows.

	Per month
Effective January 1, 2024	$19.17

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
d) The customer cannot be taking seasonal service from NSPI under Regulation 3.3.
e) The customer cannot be taking Net Metering service from NSPI under Regulation 3.6.

Optional Green Power Rider

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing "blocks" of Green Power. For every block purchased, NSPI will provide 125 kWh per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer's normal bill for service taken under the Domestic Service Time of Use Tariff.

Special Terms and Provisions

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

CUSTOMER CHARGE

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

ENERGY CHARGE

	For the first 200 kilowatt-hours per month	**For all additional kilowatt-hours**
	Cents per kilowatt-hour	
Effective February 2, 2023	16.107	14.381
Effective January 1, 2024	17.567	15.841

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be as follows.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY:

This tariff is applicable to electric energy for use where the annual consumption is less than 32,000 kWh per year and for which no other rates are applicable, and is available to customers on the General tariff where the annual consumption is less than 45,000 kWh per year.

For customers that elect to take service under the Small General tariff, where the General tariff is otherwise applicable, the following conditions apply:

- Customers must make a written request to take service under the Small General tariff.
- Customers can switch rate classes twice in a 24-month period.
- After switching, customers shall take service under this tariff for a minimum of six months subject to meeting the load threshold criteria.

SMALL GENERAL CRITICAL PEAK PRICING TARIFF

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the Small General Tariff.

CUSTOMER CHARGE

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

ENERGY CHARGE

	During a Critical Peak Event	For the first 200 kilowatt-hours per month after Critical Peak Event usage	For all additional kilowatt-hours
	Cents per kilowatt-hour		
Effective February 2, 2023	143.145	14.025	12.681
Effective January 1, 2024	144.604	15.485	14.140

The Critical Peak Event is of a four-hour duration and can be called at any time between 6:00 AM and 11:00 PM, Monday to Sunday, during the Winter Period November 1 through March 31.

The Critical Peak Event pricing applies when a Critical Peak Event is called. In all other hours in the Winter Period, and for all hours in the Non-Winter Period, the rate shall be the Non-Critical Peak Hours Rate in the table above.

CRITICAL PEAK EVENT PROCEDURE

1. In the Winter Period, Critical Peak Events exclude all hours on the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, November 11, December 25 and December 26. If January 1, November 11, December 25 or 26 fall on a weekend, the Critical Peak Events also exclude the weekday the holiday is observed.
2. Critical Peak Events will be scheduled, at the sole discretion of NSPI, when NSPI is expecting conditions including, but not limited to, high energy (kWh) usage, high market energy costs, or generation or transmission outages.
3. When a Critical Peak Event is scheduled, subscribers to this tariff will be notified in advance and the Critical Peak Event Energy Charge (higher rate) will be in effect for all kWh consumed by the customer during the period. The notification is a signal to the customer to reduce the

amount of electricity they are using.

4. Critical Peak Events will only be scheduled to occur during the Winter Period
5. No more than 18 Critical Peak Events may be scheduled per Winter season (November through March inclusive). No more than three Critical Peak Events will be scheduled per week (Monday to Sunday). No more than three Critical Peak Events per Winter season may be scheduled on a weekend.
6. Customers will be notified of a Critical Peak Event in advance. By 4:00 pm the day prior to the event, the Customer will receive a notification message. The Customer is responsible to watch for this message, and to notify NS Power in advance if their contact information changes.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be as follows.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) The customer must be on electronic billing and have a MyAccount profile.
d) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
e) The customer cannot be taking seasonal service from NSPI under Regulation 3.3.
f) The customer cannot be taking Net Metering service from NSPI under Regulation 3.6.

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the Small General Tariff.

CUSTOMER CHARGE

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

ENERGY CHARGE

Non-winter Period April 1 through October 31	**Cents per kilowatt-hour**
	All hours
Effective February 2, 2023	10.271
Effective January 1, 2024	11.731

Winter Period November 1 through March 31	**On-peak (morning)**	**Off-peak**	**On-peak (evening)**	**Off-peak**
	7:00 am to 11:00 am	**11:00 am to 5:00 pm**	**5:00 pm to 9:00 pm**	**9:00 pm to 7:00 am**
	Cents per kilowatt-hour			
Effective February 2, 2023	31.757	16.091	31.757	16.091
Effective January 1, 2024	33.217	17.551	33.217	17.551

Note 1: In the Winter Period, the off-peak price also applies to all hours on Saturdays, Sundays, and the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, November 11, December 25 and December 26. If January 1, November 11, December 25 or 26 fall on a weekend, the off-peak price shall apply on the weekday the holiday is observed.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be as follows.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
d) The customer cannot be taking seasonal service from NSPI under Regulation 3.3.
e) The customer cannot be taking Net Metering service from NSPI under Regulation 3.6.

DEMAND CHARGE

	Per month per kilowatt of maximum demand.
Effective February 2, 2023	$10.554
Effective January 1, 2024	$10.554

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

	For the first 200 kilowatt-hours per month per kilowatt of maximum demand	**For all additional kilowatt-hours**
	Cents per kilowatt-hour	
Effective February 2, 2023	13.248	9.952
Effective January 1, 2024	14.287	10.990

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than the rates in the table below.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY:

This tariff is applicable to electric power and energy where the annual consumption is 32,000 kWh, or greater and for which no other rates are applicable.

For General tariff customers eligible for the Small General tariff the following conditions apply:

- Customers must make a written request to take service under the Small General tariff.
- Customers can switch rate classes twice in a 24-month period.
- After switching, customers shall take service under this tariff for a minimum of six months subject to meeting the load threshold criteria.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.9%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

(3) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation.

(4) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

GENERAL CRITICAL PEAK PRICING TARIFF

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the General Tariff.

DEMAND CHARGE

	Per month per kilowatt of maximum demand.
Effective February 2, 2023	$10.554
Effective January 1, 2024	$10.554

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

	During a Critical Peak Event	For the first 200 kilowatt-hours per month per kilowatt of maximum demand after Critical Peak Event usage	For all additional kilowatt-hours
	Cents per kilowatt-hour		
Effective February 2, 2023	151.171	10.480	8.640
Effective January 1, 2024	152.209	11.518	9.678

The Critical Peak Event is of a four-hour duration and can be called at any time between 6:00 AM and 11:00 PM, Monday to Sunday, during the Winter Period November 1 through March 31.

The Critical Peak Event pricing applies when a Critical Peak Event is called. In all other hours in the Winter Period, and for all hours in the Non-Winter Period, the rate shall be the Non-Critical Peak Hours Rate in the table above.

CRITICAL PEAK EVENT PROCEDURE

1. In the Winter Period, Critical Peak Events exclude all hours on the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, November 11, December 25 and

December 26. If January 1, November 11, December 25 or 26 fall on a weekend, the Critical Peak Events also exclude the weekday the holiday is observed.

2. Critical Peak Events will be scheduled, at the sole discretion of NSPI, when NSPI is expecting conditions including, but not limited to, high energy (kWh) usage, high market energy costs, or generation or transmission outages.
3. When a Critical Peak Event is scheduled, subscribers to this tariff will be notified in advance and the Critical Peak Event Energy Charge (higher rate) will be in effect for all kWh consumed by the customer during the period. The notification is a signal to the customer to reduce the amount of electricity they are using.
4. Critical Peak Events will only be scheduled to occur during the Winter Period.
5. No more than 18 Critical Peak Events may be scheduled per Winter season (November through March inclusive). No more than three Critical Peak Events will be scheduled per week (Monday to Sunday). No more than three Critical Peak Events per Winter season may be scheduled on a weekend.
6. Customers will be notified of a Critical Peak Event in advance. By 4:00 pm the day prior to the event, the Customer will receive a notification message. The Customer is responsible to watch for this message, and to notify NS Power in advance if their contact information changes.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh, applying to that portion of the bill which is not concerned with determination of the cost of the Critical Peak Events, will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than the following.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) The customer must be on electronic billing and have a MyAccount profile.
d) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
e) The customer cannot be taking Net Metering service from NSPI under Regulation 3.6.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by1.9%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

(3) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation.

(4) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the General Tariff.

DEMAND CHARGE

	Per month per kilowatt of maximum demand.
Effective February 2, 2023	$10.554
Effective January 1, 2024	$10.554

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

Non-winter Period April 1 through October 31	**Cents per kilowatt-hour**
	All hours
Effective February 2, 2023	8.228
Effective January 1, 2024	9.266

Winter Period November 1 through March 31	**On-peak (morning)**	**Off-peak**	**On-peak (evening)**	**Off-peak**
	7:00 am to 11:00 am	**11:00 am to 5:00 pm**	**5:00 pm to 9:00 pm**	**9:00 pm to 7:00 am**
	Cents per kilowatt-hour			
Effective February 2, 2023	25.205	12.782	25.205	12.782
Effective January 1, 2024	26.243	13.820	26.243	13.820

Note 1: In the Winter Period, the off-peak price also applies to all hours on Saturdays, Sundays, and the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, November 11, December 25 and December 26. If January 1, November 11, December 25 or 26 fall on a weekend, the off-peak price shall apply on the weekday the holiday is observed.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than the following.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY CONDITIONS

a) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
b) The customer must be equipped with a standard Smart Meter.
c) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
d) The customer cannot be taking Net Metering service from NSPI under Regulation 3.6.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the

metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by1.9%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

(3) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation.

(4) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

SCHEDULE E

MULTI-UNIT RESIDENTIAL BUILDINGS TIME-OF-USE TARIFF

PURPOSE

This is an optional tariff designed to promote the shifting of load from peak to off-peak periods. This tariff is available to customers who are eligible for service under the General Tariff.

ENERGY CHARGE

Non-winter Period April 1 through October 31	**Off-peak**	**On-peak**
	9:00 pm to 7:00 am	**7:00 am to 9:00 pm**
Cents per kilowatt-hour		
Effective November 1, 2024	11.430	13.573

Winter Period November 1 through March 31	**On-peak (morning)**	**Mid-peak**	**On-peak (evening)**	**Off-peak**
	7:00 am to 11:00 am	**11:00 am to 5:00 pm**	**5:00 pm to 9:00 pm**	**9:00 pm to 7:00 am**
Cents per kilowatt-hour				
Effective November 1, 2024	28.574	14.287	28.574	12.144

Note 1: in both the Winter and Non-winter Periods, the applicable peak price also applies to all hours on Saturdays, Sundays, and the following holidays: January 1, Nova Scotia Heritage Day, Good Friday, Easter Monday, November 11, December 25 and December 26, including on the weekdays the holiday may be observed.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall not be less than the rates in the table below.

	Per month
Effective November 1, 2024	$21.28

AVAILABILITY CONDITIONS

a) The tariff is available to Multi-Unit Residential Buildings with a house meter and a minimum of 10 units.
b) The customer must commence service under this tariff on November 1st, unless NSPI grants a waiver.
c) The customer must be equipped with a standard Smart Meter.
d) NSPI may limit the number of customers who may subscribe to this tariff at a time, and/or close enrollment for any period of time.
e) The customer cannot be taking seasonal service from NSPI under Regulation 3.3.
f) The customer cannot be taking Net Metering service from NSPI under Regulation 3.6.

SPECIAL CONDITIONS

(1) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.9%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

(3) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation.

(4) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

DEMAND CHARGE

As follows, per month per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months.

	Per month
Effective February 2, 2023	$13.845
Effective January 1, 2024	$13.845

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

	Cents per kilowatt-hour
Effective February 2, 2023	9.850
Effective January 1, 2024	10.949

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be as follows.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY:

This tariff is applicable to electric power and energy for any use except industrial, where the regular billing demand is 2,000 kVA or 1,800 kW, and over.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the bulk power transformer.

Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustments to the metered kWh usage will be made under the following conditions:

(a) If the substation high voltage side is 69 kV or higher, and metering is on the high voltage side, meter readings shall be reduced by1.1%.

(b) If the substation high voltage side is lower than 69 kV, and metering is on the low voltage side, meter readings shall be increased by1.1%.

(2) The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a billing demand of 2,000 kVA or 1,800 kW.

(3) The Company reserves the right to have a separate service and/or operating agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

DEMAND CHARGE

	Per month per kilovolt ampere of maximum demand
Effective February 2, 2023	$8.332
Effective January 1, 2024	$8.332

32 cents per kilovolt ampere reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

	For the first 200 kilowatt-hours per month per kilovolt ampere of maximum demand	**For all additional kilowatt-hours**
	Cents per kilowatt hour	
Effective February 2, 2023	12.004	9.430
Effective January 1, 2024	13.237	10.663

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than as follows.

MINIMUM MONTHLY CHARGE

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any customer, for industrial use, including farming and processing, where the regular billing demand is less than 250 kVA or 225 kW.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering.
Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.9%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

DEMAND CHARGE

	Per month per kilovolt ampere of maximum demand.
Effective February 2, 2023	$13.796
Effective January 1, 2024	$13.796

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

	Cents per kilowatt-hour
Effective February 2, 2023	9.345
Effective January 1, 2024	10.421

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be as follows.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any industrial customer having a regular billing demand of 250 kVA (225 kW) and over, and for which no other rates are applicable.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.1%.

(2) The Company may withdraw the availability of this tariff to any specific customer, if, in the opinion of the Company, the customer is not maintaining a billing demand of 250 kVA (225 kW).

(3) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation.

(4) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

DEMAND CHARGE

As follows, per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven (11) months.

	Per month
Effective February 2, 2023	$12.601
Effective January 1, 2024	$12.601

DISTRIBUTION COST ADDER

For customers connected at distribution level, the following charge also applies, subject to the same provisions as the Demand Charge section above.

	Per month
Effective February 2, 2023	$1.632
Effective January 1, 2024	$1.632

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer

ENERGY CHARGE

	Cents per kilowatt-hour	
	Firm Customers	**Interruptible Customers**
Effective February 2, 2023	9.639	9.639
Effective January 1, 2024	10.184	10.184

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the greater of the demand charge or the amounts in the table below.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY:

This tariff is applicable to three phase electric power and energy supplied at the low voltage side of the bulk power transformer to any industrial customer having a regular billing demand of 2 000 kVA or 1 800 kW, and over.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the bulk power transformer. At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by1.1% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The Company will withdraw the availability of this tariff to any specific firm load only customer, if, on a consistent basis, the customer is not maintaining a regular demand of 2 000 kVA or 1,800 kW or, as a result of transferring to this tariff from the Medium Industrial category the customer would not see a reduction in his electric cost for the energy supplied. Any customer whose total or partial load is billed under the interruptible rider to this tariff and whose total demand fell, on a consistent basis, below 2 000 kVA or 1,800 kW after subscription to the interruptible service will be exempted from the minimum load requirement of this tariff.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of

the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

INTERRUPTIBLE RIDER TO THE LARGE INDUSTRIAL TARIFF (Rate Code 25)

Customers who qualify for interruptible service will receive a per month per kilovolt ampere reduction in demand charge for billed interruptible demand, as shown in the table below The billed interruptible demand is defined as the difference between any contracted firm demand requirements and the total billing demand. Where the billing demand is less than the contracted firm demand, no interruptible credit shall apply. The billed interruptible demand will be the maximum interruptible demand of the current month or the maximum actual interruptible demand of the previous December, January or February occurring in the previous eleven (11) months.

	Reduction per kilovolt ampere reduction in demand charge
Effective February 2, 2023	$7.486
Effective January 1, 2024	$7.486

AVAILABILITY:

This rider will be applicable to an agreed upon, between the Company and the customer, interruptible billing demand at 90% Power Factor, under the following terms and conditions:

(1) The customer has provided written notice of his desire to take service under this option, identifying that portion of the load that is to be firm and that portion that is to be interruptible.

(2) The customers will reduce their available interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.

Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by the Company, the Company may hold this load as Operating Reserve as required by system conditions. When interruptions are required, the Company will exercise the automated control of the customer's load to interrupt the customer load.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(5) Should any customer under this rider desire to be served under any appropriate firm service rate, a five (5) year advance written notice must be given to the Company so as to ensure adequate capacity availability. Requests for conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to interruptible service in the future, the Customer may convert to interruptible service following two (2) years of service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

(6) Interruption is limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours in a year.

SPECIAL CONDITIONS:

(1) The Company reserves the right to have a separate service agreement if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.1% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

DEMAND CHARGE

As follows, per month per kilovolt ampere of the higher of:

(a) maximum actual demand of the current month or

(b) the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months but excluding the actual monthly peak demands recorded during the first two hours following restoration of any outage of at least one hour in duration. In this circumstance, the next highest monthly peak demand, registered outside of the restoration period, will be used. Customers will make reasonable efforts to manage post-restoration demand peaks.

	Per month
Effective February 2, 2023	$13.428
Effective January 1, 2024	$13.428

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

	Cents per kilowatt-hour
Effective February 2, 2023	9.311
Effective January 1, 2024	10.133

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the customer for the current rate year, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

AVAILABILITY:

This tariff is applicable to three phase electric power and energy, supplied at the low voltage side of the bulk power transformer, to municipal electric utilities. Meter readings shall be increased by 1.1% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformation losses. Also, meter readings shall be reduced when metering is at transmission voltage.

ENERGY CHARGE

	Cents per kilowatt-hour
Effective February 2, 2023	17.838
Effective January 1, 2024	17.873

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

AVAILABILITY

This rate is available to all outdoor recreational lighting for the period May through October only.

Note: Rates listed under 2023 and 2024 shall be in effect starting February 2 and January 1 respectively

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in Cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

STORM COST RECOVERY RIDER

Storm Cost Recovery Charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

(A) STREET AND AREA LIGHTING

AVAILABILITY:

These rates shall be applicable to the supply, operation and maintenance, or where indicated, operation and maintenance only, of street and area lighting. Except where otherwise indicated, the rates apply to fixtures operating for approximately 4000 hours per year. Maintenance does not include globe washing, cleaning, repair, or replacement of parts or bulbs necessitated by vandalism. Such costs will be charged to the customer.

RATES

(1) INCANDESCENT

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Month.**	**2023**	**2024**	
001	300 and less	97	21.63	21.66	
002	Greater than 300	154	31.78	31.83	

b) Operating Only

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Month.**	**2023**	**2024**	
003	300 and Less	97	23.59	23.62	

(2) MERCURY VAPOUR

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
100	100	43	13.56	13.57	
101	125	52	15.15	15.17	
102	175	69	17.89	17.91	
103	250	97	23.59	23.62	
104	400	154	33.69	33.74	
105	700	260	53.60	53.69	
106	1000	363	72.81	72.94	
107	250	212	36.94	37.02	Continuous Operation

b) Operating and Maintenance Only

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
201	125	52	10.04	10.06	
202	175	69	12.80	12.82	
203	250	97	17.72	17.75	
204	400	154	27.74	27.79	
205	700	260	46.37	46.46	
206	1000	363	64.47	64.60	

c) Operating Only

Rate Code	Watts	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	Other
301	125	52	9.14	9.16	
302	175	69	12.13	12.15	
303	250	97	17.05	17.08	
304	400	154	27.07	27.12	
305	700	260	45.70	45.79	
306	1000	363	63.80	63.93	

(3) FLUORESCENT

a) Operating, Maintenance and Capital (Full Charge)

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	other
110	24	2	30	11.12	11.13	
111	48	2	85	21.06	21.09	
112	72	2	116	27.01	27.05	
113	72	4	222	46.88	46.95	
114	96	1	47	14.68	14.70	
115	72	1	60	16.56	16.58	
116	48	4	166	35.91	35.96	

b) Operating and Maintenance Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	Other
213	72	4	222	40.37	40.44	
214	96	1	47	9.61	9.63	
215	72	1	60	11.90	11.92	
216	48	4	166	30.53	30.58	
217	48	1	49	9.96	9.98	

218	48	2	85	16.29	16.32	

c) Operating Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)		Other
				2023	2024	
330	35	4	47	8.26	8.28	

(4) FLUORESCENT CROSSWALK

a) Continuous Burning - Operating Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)		Other
				2023	2024	
117	72	4	486	68.16	68.33	
118	24	2	66	9.26	9.28	
119	48	4	364	51.05	51.18	
120	96	2	254	35.62	35.71	
150	96	4	613	85.97	86.19	

b) Photocell Operation - Operating Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)		Other
				2023	2024	
310	24	2	30	5.27	5.28	
311	48	4	166	29.18	29.23	
312	72	2	116	20.39	20.43	
313	72	4	222	39.02	39.09	
314	96	1	47	8.26	8.28	
315	72	1	60	10.55	10.57	
350	96	4	280	49.21	49.31	

(5) LOW PRESSURE SODIUM

a) Operating, Maintenance and Capital (Full Charge)

Rate Code	Watts	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	Other
130	135	60	20.70	20.72	
131	180	80	27.01	27.04	
132	90	45	18.06	18.07	

b) Operating and Maintenance Only

Rate Code	Watts	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	Other
231	180	80	16.08	16.11	

c) Operating Only

Rate Code	Watts	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	Other
331	180	80	14.06	14.09	

(6) HIGH PRESSURE SODIUM

a) Operating, Maintenance and Capital (Full Charge)

Rate Code	Watts	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	Other
121	250	100	23.60	23.63	
122	400	150	32.51	32.57	
123	70	32	11.43	11.45	
124	100	45	13.75	13.76	
125	150	65	17.45	17.48	
126	100	99	20.39	20.43	Continuous Operation

b) Operating and Maintenance Only

Rate Code	Watts	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	Other
221	250	100	18.25	18.28	
222	70	32	6.29	6.31	
223	100	45	8.58	8.59	
224	150	65	12.09	12.12	

c) Operating Only

Rate Code	Watts	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	Other
321	250	100	17.58	17.61	
322	70	32	5.62	5.64	
323	100	45	7.91	7.92	
324	150	65	11.42	11.45	
326	400	150	26.36	26.42	
327	500	183	32.16	32.23	
328	1000	363	63.80	63.93	
329	1500	500	87.88	88.05	

(7) METALLIC ADDITIVE

a) Operating, Maintenance and Capital (Full Charge)

Rate Code	Watts	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	Other
140	400	150	33.42	33.48	
141	1000	360	72.77	72.90	
142	250	100	25.12	25.15	
143	150	67	19.32	19.34	
144	100	50	16.33	16.35	

b) Operating Only

Rate Code	Watts	kWh/Mo.	Per Month ($) 2023	Per Month ($) 2024	Other

341	1000	360	63.27	63.40	
342	400	150	26.36	26.42	
343	250	100	17.58	17.61	
344	175	75	13.18	13.21	
345	150	67	11.78	11.80	
346	100	50	8.79	8.81	

(8) LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
530	4.6	3	0.53	0.53	Non-Continuous
531	7.5	5	0.88	0.88	Continuous

(9) LIGHT EMITTING DIODE (LED) – Operating Only

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
532	44	15	2.64	2.64	
533	66	22	3.87	3.87	
534	88	29	5.10	5.11	
535	92	31	5.45	5.46	
536	105	35	6.15	6.16	
537	173	57	10.02	10.04	
538	44	15	2.64	2.64	
539	110	37	6.50	6.52	
540	65	22	3.87	3.87	
541	55	18	3.16	3.17	
542	83	28	4.92	4.93	
543	48	16	2.81	2.82	
544	72	24	4.22	4.23	
546	43	14	2.46	2.47	
547	50	17	2.99	2.99	
548	53	18	3.16	3.17	

549	80	27	4.75	4.75	
550	200	67	11.78	11.80	
551	60	20	3.52	3.52	
552	70	23	4.04	4.05	
553	87	29	5.10	5.11	
554	173	58	10.19	10.21	
555	35	12	2.11	2.11	
556	51	17	2.99	2.99	
557	172	57	10.02	10.04	
558	91	30	5.27	5.28	
559	42	14	2.46	2.47	
560	13	4	0.70	0.70	
561	8	3	0.53	0.53	
562	150	50	8.79	8.81	
563	60	20	3.52	3.52	
564	28	9	1.58	1.58	
565	86	29	5.10	5.11	
567	100	33	5.80	5.81	
569	143	48	8.44	8.45	
570	200	67	11.78	11.80	
572	250	83	14.59	14.62	
573	52	17	2.99	2.99	
574	140	47	8.26	8.28	
575	185	62	10.90	10.92	
576	95	32	5.62	5.64	
578	75	25	4.39	4.40	
579	138	46	8.08	8.10	
582	54	18	3.16	3.17	
583	175	58	10.19	10.21	
584	46	15	2.64	2.64	
585	69	23	4.04	4.05	
586	108	36	6.33	6.34	
587	158	53	9.31	9.33	
589	48	16	2.81	2.82	
590	90	30	5.27	5.28	
591	240	80	14.06	14.09	
592	135	45	7.91	7.92	
593	30	10	1.76	1.76	

594	133	44	7.73	7.75	
595	55	18	3.16	3.17	
596	52	17	2.99	2.99	
597	41	14	2.46	2.47	
598	68	23	4.04	4.05	
599	117	39	6.85	6.87	

(10) LIGHT EMITTING DIODE (LED) – Operating, Maintenance & Capital (full charge)

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
615	44	15	10.68	10.68	
616	55	18	11.20	11.21	
623	28	9	9.62	9.62	
624	50	17	11.03	11.03	
625	72	24	12.26	12.27	
626	100	33	13.84	13.85	
627	200	67	19.82	19.84	

(11) LIGHT EMITTING DIODE (LED) – Operating, Maintenance & Capital (full charge)

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
724	55	18	9.15	9.16	
740	190	63	23.44	23.46	
741	261	87	29.01	29.04	
742	124	41	17.36	17.37	
743	84	28	14.55	14.56	

(B) MISCELLANEOUS LIGHTING

DEMAND CHARGE

	Per month per kilowatt of connected load
Effective February 2, 2023	12.314
Effective January 1, 2024	12.314

ENERGY CHARGE

	For the first 200 kilowatt hours per month per kilowatt of maximum demand	**For all additional kilowatt hours**
	Cents per kilowatt-hour	
Effective February 2, 2023	15.774	11.042
Effective January 1, 2024	15.809	11.077

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill for the electric power and energy portion of the Miscellaneous Lighting Rate shall be $ as follows per month if such unmetered service is billed separately from any metered account.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

CAPITAL CHARGE: (if applicable)

Depreciation based on a 25 year life, and interest at the Company's long term rate shall be used to determine the monthly capital charge.

MAINTENANCE CHARGE: (if applicable)

Cost of normal fixture maintenance and bulb replacement on the basis of current cost levels shall be used to calculate the monthly maintenance charge.

This portion of the rate does not include any provision for globe washing or cleaning. Repair or replacement of parts or bulbs necessitated by vandalism will be charged to the customer.

AVAILABILITY:

This rate shall be applicable to the supply, operation and maintenance of lighting units not provided

for under the Street and Area Lighting rate.

(C) **MISCELLANEOUS SMALL LOADS**

DEMAND CHARGE

	Per month per kilowatt of connected load
Effective February 2, 2023	12.314
Effective January 1, 2024	12.314

ENERGY CHARGE

	For the first 200 kilowatt hours per month per kilowatt of maximum demand	**For all additional kilowatt hours**
	Cents per kilowatt-hour	
Effective February 2, 2023	15.774	11.042
Effective January 1, 2024	15.809	11.077

The flat rate calculation (using a 30 day month) will be based on the specific information of each service using the above rate. The charge will be expressed in cents per kWh per month and will be rounded to hundredths of a cent in its application.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall be as follows per month if such unmetered service is billed separately from any metered account.

	Per month
Effective February 2, 2023	$21.28
Effective January 1, 2024	$21.28

AVAILABILITY:

A flat rate shall be calculated for any service requiring the supply of power and energy only, with a predeterminable usage, and where metering is considered to be impractical, such as: Telephone Booths, Cable Vision Power Supplies, Traffic Control Lights, Police Telephones, Railway Signals,

etc.

APPLICABILITY:

This schedule is a mandatory rider to all electric rate schedules, except the following tariffs: Generation Replacement and Load Following, Extra High Voltage Time-of-Use Real Time Pricing, High Voltage Time-of-Use Real Time Pricing, Distribution Voltage Time-of-Use Real Time Pricing. FAM adjustments will apply to the Standard Energy Charge of the Extra Large Industrial 2P-RTP tariff. FAM adjustments will apply to Additional Energy supplied under the Mersey System Agreement when Additional Energy is priced at a tariff to which FAM adjustments apply.

FUEL ADJUSTMENT:

The applicable charges for electric service to the Company's retail and municipal customers shall be increased or decreased to the nearest 0.001 cents per kWh to recover or credit the difference in actual fuel cost from the costs in base rates in accordance with the following rate class-specific formula:

Fuel Adjustment Rider = AA + BA

Where:

"AA" is a rate class-specific Actual Adjustment which is the difference between fuel-related costs recovered from a rate class through the application of the base rates during the previous calendar year and the actual Fuel Costs incurred and allocated to the rate class for the same time period. The actual fuel costs will include the same cost items as base fuel costs.

"BA" is a rate class-specific Balance Adjustment which accounts for any over- or under-collections which have occurred as a result of prior adjustments.

SPECIAL CONDITIONS:

(1) Base Cost of Fuel

The Base Cost of Fuel can be re-set in a General Rate Application or, absent a General Rate Application, every second year as part of the FAM adjustment process. Changes in the Base Cost of Fuel will be reflected in customers' rates going forward and will be applied to each customer class in a manner consistent with the then-current Board-approved Cost of Service Methodology.

(2) Incentive

For a total fuel cost variance of up to $50 million dollars (Actual Fuel Costs - [(Actual Sales) x (Base Fuel Cost $/Mwh)]), 90% of any savings or increase in cost will be credited or charged to customers. The portion of any variance that is in excess of $50 million dollars will be fully applied in the calculation of the "AA". Credits or charges will be applied to the energy component of rates on a cents per kWh basis.

(3) Load Migration to non-FAM classes

When a customer transitions its load, whether in whole or in part, from a FAM class to a non-FAM class, NS Power shall determine the outstanding fuel cost imbalance of the customer at the time of transition. This determined imbalance will be adjusted as necessary in future FAM proceedings concerned with apportionment of fuel costs incurred in the period in question. The adjustments will be subject to UARB approval. The outstanding imbalance and subsequent adjustments will be paid (or reimbursed) in full on reasonable terms acceptable to the customer and NS Power, or if the parties are unable to agree, as determined by the UARB.

The applicable charges by rate class are as follows.

	Effective upon the date of the Board's decision		
Rate Class	**Actual Adjustment (AA) in cents per kWh**	**Balance Adjustment (BA) in cents per kWh**	**FAM AA/BA Combined in cents per kWh**
Domestic Service, Domestic Service Time-of-Day, Domestic Service Time of Use, Domestic Service Critical Peak Pricing	0.467	0.156	0.623
Small General, Small General Time of Use, Small General Critical Peak Pricing	0.396	0.156	0.552
General, General Time of Use, General Critical Peak Pricing	0.392	0.207	0.599
Large General	0.359	0.158	0.517
Small Industrial	0.394	0.144	0.538
Medium Industrial	0.358	0.206	0.564
Large Industrial Firm	0.366	0.247	0.613
Large Industrial Interruptible	0.366	0.224	0.590
Municipal	0.418	0.105	0.523
Outdoor Recreational Lighting	0.413	0.156	0.569
Unmetered	0.413	0.156	0.569

APPENDIX A

PURPOSE

The Solar Garden Pilot Rate Rider is an optional tariff that will provide eligible NSPI customers in good standing the opportunity to subscribe up to 100% of their annual energy consumption from the generation output of a 2,000 kW Solar Garden in the Town of Amherst, Nova Scotia as part of the scope of NS Power's Smart Grid Nova Scotia Project, which was approved by the Nova Scotia Utility and Review Board on May 7, 2020. Customers taking this service will be referred to as "community solar subscribers".

AVAILABILITY

The Solar Garden Pilot Rate Rider is available on a first-come, first-served basis to customers who have annual consumption of less than 10,000 MWh per year. Customers served in Amherst where the Solar Garden will be located will have subscription priority over other customers.

60 percent of the capacity of the Solar Garden will be reserved for domestic customers, and the remainder for other customer classes.

Subscription will be limited to the total nameplate capacity of the facility, to be confirmed upon completion of the construction of the facility.

Customers who take Net Metering Service are not eligible for the SGNS Solar Garden Pilot Rate Rider.

APPLICABILITY

A customer will receive generation output from the Solar Garden on the basis of their subscription to installed capacity of the Solar Garden in 0.25 kW increments. The maximum kW of the customer's subscription will be sized to meet their expected annual consumption or 100 kW, whichever is smaller. No individual customer will be allowed to subscribe to more than 100 kW of installed capacity of the Solar Garden.

MONTHLY SOLAR CAPACITY CHARGE

A customer may subscribe to capacity of the Solar Garden by paying a Monthly Solar Capacity Charge for each kW increment subscribed. The subscription fee is paid monthly that accounts for the costs to build, operate and maintain the Solar Garden, and the administration costs to operate the Community Solar Pilot.

The Customer shall continue to pay the fee, even if solar garden generation is temporarily interrupted for any reason. Subscribers will be notified by email of any interruptions lasting longer than three days and involving more than 25% of the solar garden capacity. Subscribers can cancel their subscription at any time.

Monthly Solar Capacity Charge

$6.86 per kW subscribed.

The same charge will apply regardless of the customer's current rate class.

SOLAR ENERGY CREDIT

Customers under the Solar Garden Pilot Rate Rider will receive a credit on their NS Power bill for the amount of subscribed generated output from the Solar Garden as a "per kWh" line item on each participant's bill.

The monthly Solar Energy Credit will be equal to the product of:

- The Solar Energy Credit rate as set forth below and
- The proportional share measured in kWh of the total monthly generation output from the Solar Garden for that month to which the Solar Energy Credit is applicable is determined on the basis of the number of subscribed kW. The month in which the Solar Energy Credit is applied to the customer's bill may not match the month in which the energy was generated due to the timing of the billing cycle.

The Solar Energy Credit will be applied to the customer's bill. The Solar Energy Credit will reflect the value of the energy provided by the Smart Grid Nova Scotia Solar Garden. Credits will be paid out every billing period. For accounts billed under domestic time-of-day services, the value of the Solar Energy Credit does not change per distinct time-of-use period.

The Solar Energy Credit is calculated and applied based on the actual generation of the Solar Garden.

The solar energy credit will be 5.493 c/kWh in 2021, and will be automatically adjusted with a two percent increase on an annual basis per the schedule below.

Year	Cents per kilowatt hour (c/kWh)
2021	5.493
2022	5.603
2023	5.715
2024	5.829
2025	5.946

The same credit will apply regardless of the customer's current rate class.

BILLING & METERING

Customers under the Solar Garden Pilot Rate Rider will also be billed the otherwise applicable Tariffs.

Solar Energy Credits will be measured based on the total metered production of the Solar Garden to the grid, as measured by the billing meter on the Smart Grid Nova Scotia Solar Garden site. This will be the generation net of any consumption for operation of the Solar Garden.

Customers will receive information on the performance of the Solar Garden via email each month, in addition to their utility bill.

NS Power reserves the right to modify the Customer's current billing cycle if it contributes to operating the Solar Garden and Solar Garden Pilot Rate Rider more efficiently. In such a circumstance, NS Power would notify the Customer at the time of subscription or, where the modification occurs following subscription, with 30 days notice.

SPECIAL PROVISIONS

1) NS Power reserves the right to deny or terminate subscriptions under this tariff to customers in arrears with the Company. Customers who are denied or terminated may subscribe for service to the Solar Garden Pilot Rate Rider upon their reinstatement of good standing with the Company and will be accommodated on a first come, first serve basis. For clarity, reinstated customers will not resume their original subscription in the Solar Garden Pilot Rate Rider, but will be treated as a new subscriber and may be placed on a waitlist if applicable.
2) Service under the Solar Garden Pilot Rate Rider may be limited at the discretion of the Company.
3) NS Power has the right to complete regular maintenance at its sole discretion, and may repair or replace any equipment as necessary without notice to the Customer of such changes(s). NS Power will endeavor to do so in a manner that minimizes impact to subscribing customers.
4) Customers who move and maintain utility service with NS Power may maintain their subscription.
5) Customers may cancel their subscription at any time and can apply to resubscribe at any time. Customers resubscribing will be placed on a waiting list as any new subscriber in the event capacity to the solar garden is fully subscribed.
6) Customers who subscribe once the Solar Garden and Solar Garden Pilot Rate Rider are operational will begin incurring charges and accruing credits upon confirmation of their subscription capacity. All charges and credits will be pro-rated to the date of confirmation.
7) NS Power will be held harmless for the failure to realize energy credits should the Solar Garden Pilot Rate Rider close for any reason.

8) The Solar Garden Pilot Rate Rider will be reevaluated at the end of NS Power's Smart Grid Nova Scotia Project Pilot as part of its asset disposition appliction, and adjustments to the tariff may be made at that time, subject to NSUARB approval.
9) Adjustments to the monthly solar capacity charge and solar energy credit may be made at any time, but must, on a net basis, be economically favourable to subscribers until 2031. After 2031, or an earlier point in time if changes to the charge and credit are made that result in positive cumulative benefit before then, the one-way ratchet should be eliminated and the tariff shall be open for review.

PURPOSE

The Community Solar Energy Credit Rider is an optional tariff rider that will provide eligible NS Power customers in good standing the opportunity to subscribe to solar energy capacity (kW_{ac}) offered by Project Owners who have been approved by the Minister of Natural Resources and Renewables to operate a Community Solar Garden under the *Community Solar Program Regulations* and who have entered into a Power Purchase Agreement with NS Power for the sale of solar energy from that facility.

Customers taking this service will be referred to as "Community Solar Program subscribers" and can subscribe to solar energy capacity with the potential to generate up to 100% of their annual energy (kWh) consumption from the generation output of a Community Solar Garden.

AVAILABILITY

The Community Solar Energy Credit Rider is available to customers who are identified to NS Power by Project Owners to meet the eligibility criteria, as set solely by the Project Owner, of a specific Community Solar Garden. Subscription will be limited to the total nameplate capacity of each of the facilities.

The Community Solar Energy Credit Rider is not available to customers who are participating in a net-metering program under Sections 3A and 3AA of the *Electricity Act*, per Section 21(1)(b) of the *Community Solar Program Regulations*, or under Regulation 3.6. Otherwise, subscribers must be a customer in good standing with NS Power and cannot be subscribed to the Solar Garden Pilot Rate Rider. Subject to the aforenoted availability criteria, the Community Solar Energy Credit Rider is available to all metered NS Power customer classes.

APPLICABILITY

A customer agrees to a subscription to solar energy capacity, in 0.25 kW_{ac}[1] increments, that is calculated to produce an amount of energy equal to the customer's chosen solar offset and based on the technical specifications of the subscribed Community Solar Program Solar Garden ("CSP Solar Garden") as reported by the Project Owner. The maximum kW_{ac} of the customer's subscription will be sized to meet the customer's average annual consumption. No individual customer will be allowed to subscribe to more solar energy capacity than would be expected to generate 100% of their average annual consumption. Subscription capacity of a CSP Solar Garden subscription is calculated as follows:

$$Subscription\ Capacity\ (kW_{ac}) = \frac{Customer\ Average\ Annual\ Electricity\ Consumption\ \left(\frac{kWh}{year}\right) * Customer\ Solar\ Offset\ (\%)}{8760\ hours\ per\ year * CSP\ Solar\ Garden\ Capacity\ Factor}$$

[1] A kilowatt alternating current (kWac) refers to the electric power, in kilowatts, associated with the alternating current output of a system at unity power factor. In this context, kWac is used to denote the maximum output capacity of a CSP Solar Garden.

Where:

- Customer Average Annual Electricity Consumption is calculated as a three-year average, when possible, or is estimated using other available data at the sole discretion of NS Power.
- Customer Solar Offset (%) is chosen by the customer.
- CSP Solar Garden Capacity Factor2 is reported by the Project Owner for each individual Project.

The subscription entitles the customer to a Solar Energy Credit for the applicable generation output from their subscription. This is calculated as:

$$Solar\ Energy\ Credit = Subscriber\ Attributable\ Share\ (\%) * Monthly\ Total\ Net\ Production\ of\ Solar\ Energy\ (kWh) * Value\ of\ Solar\ Energy\ Credit(\$\ /\ kWh)$$

Where:

- The monthly total net production of solar energy is measured as the solar energy sent to the grid, net of any consumed at the CSP Solar Garden.
- A subscriber's attributable share is calculated, as per Section 30 of the *Community Solar Program Regulations,* as:

$$Subscriber\ Attributal\ Share\ (\%) = \frac{Subscription\ Capacity\ (kW_{ac})}{Installed\ Capacity\ of\ the\ CSP\ Solar\ Garden\ (kW_{ac})}$$

SOLAR ENERGY CREDIT

Customers under the Community Solar Energy Credit Rider will receive a credit on their NS Power bill for the value of solar energy generated from their subscription in accordance with Section 5 of the *Community Solar Program Regulations*.

In accordance with Section 3(h) of the *Community Solar Program Regulations*, the Value of Solar Energy Credit is 2.000 cents per kWh for the duration of the subscription, subject to amendments per Section 39 of the *Community Solar Program Regulations*. The same credit will apply regardless of the customer's current applicable tariff.

The Solar Energy Credit is calculated and applied based on the actual generation of the CSP Solar Garden.

The Solar Energy Credit is calculated as the attributable share of measured net production in kWh of the total monthly generation output from the CSP Solar Garden for that month to which the subscription is applicable.

[2] The capacity factor of a solar garden is the ratio of the actual energy produced by the garden over a specific period to the maximum possible energy it could have produced at full capacity during that same period. For the purposes of the calculation, it will use the reported estimated annual AC capacity factor prior to the project's operation.

Credits will be applied to a subscriber's bill every billing period. The month in which the Solar Energy Credit is applied to the customer's bill may not match the month in which the energy was generated due to the timing of the billing cycle. For accounts billed under time-of-day or time-varying pricing tariffs, the value of the Solar Energy Credit does not change per distinct time-of-use, time-of-day, or critical peak period.

NO ADDITIONAL FEES

A customer may subscribe to a CSP Solar Garden with no additional fees related to their subscription, in accordance with Section 4 of the *Community Solar Program Regulations*.

BILLING & METERING

Customers under the Community Solar Energy Credit Rider will also be billed in accordance with the otherwise applicable Tariffs.

Solar Energy Credits will be measured based on the total metered production of the CSP Solar Garden to the grid, as measured by the billing meter on the CSP Solar Garden site. This will be the generation net of any consumption for operation of the CSP Solar Garden.

NS Power reserves the right to modify the Customer's current billing cycle if it contributes to operating the CSP Solar Garden and Community Solar Energy Credit Rider more efficiently. In such a circumstance, NS Power would notify the Customer at the time of subscription or, where the modification occurs following subscription, with 30 days' notice.

RENEWABLE ENERGY CERTIFICATES

In accordance with Section 38 of the *Community Solar Program Regulations*, upon request by a non-residential Community Solar Program subscriber, NS Power will register and retire renewable energy certificates (RECs) on behalf of the subscribing customer and will provide to that customer, no later than March 31 of each year, the following information:

- the annual volume of the customer's RECs;
- the customer's REC serial or identification numbers; and
- the vintage[3] of the customer's RECs.

All costs of registering and retiring RECs are paid by the Project Owner. When requesting RECs, the Subscriber agrees that the total electrical energy output of Community Solar Gardens under the Community Solar Program shall be counted by NS Power toward its compliance with the renewable electricity standard requirements set forth in the *Renewable Electricity Regulations* (N.S. Reg 338/2022), as per Section 38(3) of the *Community Solar Program Regulations*, and the Subscriber shall take no actions to utilize or take credit for environmental attributes related to their

[3] The vintage of a REC refers to the year in which the renewable energy and environmental attributes associated with the REC was generated.

subscription in a manner that could hinder NS Power from doing so.

SPECIAL PROVISIONS

1) NS Power reserves the right to deny or terminate subscriptions under this tariff to customers in arrears with the Company. Customers who are denied or terminated may subscribe for service to the Community Solar Energy Credit Rider upon their reinstatement of good standing with the Company and will be accommodated on a first come, first served basis. For clarity, reinstated customers will not resume their original subscription in the Community Solar Energy Credit Rider but will be treated as a new subscriber and may be placed on a waitlist if applicable. All credits will be pro-rated to the date of termination.

2) Subject to NS Power's requirements in accordance with the *Electricity Act (Nova Scotia)*, the *Community Solar Program Regulations*, and the Community Solar Program Guidelines, service under the Community Solar Energy Credit Rider may be limited at the discretion of the Company.

3) NS Power is not responsible for maintenance or performance of any CSP Solar Garden and takes no responsibility for performance that affects the value of a subscription at any time. NS Power is not responsible for communicating to subscribers the status of a CSP Solar Garden's performance or whether or not a Project Owner communicates information with subscribers on performance and impact to subscriptions.

4) Customers who move and maintain utility service with NS Power may maintain their subscription, so long as they still meet the project's eligibility criteria as determined solely by the Project Owner and have the consent of the Project Owner to do so.

5) Customers may cancel their subscription at any time and can apply to the Project Owner to resubscribe at any time. Customers resubscribing will not resume their original subscription in the Community Solar Energy Credit Rider but will be treated as a new subscriber and may be placed on a waitlist, if applicable. All credits will be pro-rated to the date of cancelation.

6) Customers who subscribe once the CSP Solar Garden and Community Solar Energy Credit Rider are operational will begin accruing credits upon confirmation of their subscription capacity. All credits will be pro-rated to the date of confirmation.

7) No customers that subscribe to the Community Solar Energy Credit Rider, nor any Project Owner of a Community Solar Garden, can take any steps to advance a claim or action against NS Power for the failure to realize Solar Energy Credits should the Community Solar Program or the Community Solar Energy Credit Rider close or should the associated CSP Solar Garden fail to generate solar energy for any reason.

APPLICABILITY:

This schedule applies to all electric rate classes with the exception of the Wholesale Market Non-Dispatchable Supplier Spill Tariff, the Load Retention Tariff, and the Extra Large Industrial Active Demand Control Tariff. For customers taking service in the Wholesale or Renewable to Retail markets, recovery of the costs of electricity efficiency and conservation activities, as defined in Section 79A of the Public Utilities Act (Demand Side Management or DSM) approved by the Nova Scotia Utility and Review Board (NSUARB) will be direct billed in accordance with the customer's class energy bill as if served by Nova Scotia Power Incorporated (NS Power) under its bundled service offerings.

RESPONSIBILITIES OF FRANCHISE HOLDER

It is the responsibility of the holder of the electric efficiency and conservation franchise granted under Section 79C of the Public Utilities Act (Franchise Holder) to apply to the Nova Scotia Utility and Review Board (NSUARB) to seek approval of all DSM activities, plans and programs and to itemize and seek approval for all related costs.

On or before October 1 in the year preceding the implementation of the approved programs, NS Power shall apply to the NSUARB to seek approval of the DSM Cost Recovery Rider amounts to be inserted in Schedule A to this tariff for the succeeding rate year. NS Power shall pay to the Franchise Holder the amount approved by the NSUARB to fund the DSM costs, on a monthly basis.

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DCRR):

The monthly amount computed under each of the rate schedules to which this DSM Cost Recovery Rider is applicable shall be increased or decreased by the DCRR at a class- specific rate per kilowatt hour of consumption in accordance with the following formula:

DCRR = PCR + BA

Where:

PCR = PROGRAM COST RECOVERY

The PCR includes all estimated costs for the upcoming calendar year for the DSM Plan that has been requested by the Franchise Holder and approved by the NSUARB (Approved DSM). It includes the cost of planning, developing, implementing, monitoring, evaluating and verifying DSM programs, and includes but is not limited to costs for enabling strategies, consultants, employees and administrative expenses. The PCR is computed for each rate schedule using the cost allocation methodology set out in Schedule B to this tariff.

BA = BALANCE ADJUSTMENT

The BA is calculated for each rate class separately on a previously completed calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the PCR and the revenues which should have been billed, as follows:

(1) The balance adjustment amount is the difference between the amount billed in the previously completed calendar year from the application of the PCR unit charges and the actual cost of the Approved DSM during the same previously completed calendar year. In order to enable incorporation of a full year's actual results, the BA will address differences in the year 2 years prior to the current PCR year[1].

The NSUARB approved DCRR shall be placed into effect with bills rendered on and after the effective date of such change.

Schedule A

2025 DSM COST RECOVERY RIDER CHARGES

The Demand Side Management Cost Recovery Rider (DCRR) charges, along with its components, (PCR) and (BA), for the period from the approved effective date of January 1, 2025 to December 31, 2025 are as follows

Applicable Tariff	PCR (cents per kWh)	BA (cents per kWh)	DCRR (cents per kWh)
Domestic Service, Domestic Service Time-of-Day, Domestic Service Time of Use, Domestic Service Critical Peak Pricing	0.657	-0.024	0.633
Small General, Small General Time of Use, Small General Critical Peak Pricing	0.778	-0.025	0.753
General, General Time of Use, General Critical Peak Pricing	0.635	0.010	0.646
Large General	0.768	0.022	0.790
Small Industrial	0.720	0.033	0.753

[1] Balance Adjustment for 2023 will come into effect on January 1, 2025 and will be based on the revenue collected between February 2, 2023, and December 31, 2023. The revenue will be compared to the DSM costs incurred in that same period.

Applicable Tariff	PCR (cents per kWh)	BA (cents per kWh)	DCRR (cents per kWh)
Medium Industrial	0.306	0.008	0.314
Large Industrial including. Interruptible Rider	0.404	0.027	0.430
Municipal	0.650	-0.023	0.628
Unmetered Services	0.353	0.004	0.357
Gen. Replacement & Load Following	0.110	-0.069	0.040
One Part Real Time Pricing	0.095	-0.004	0.091
Shore Power	0.095	0.059	0.153

Schedule B

DSM COST ALLOCATION APPROACH

There are 3 kinds of cost benefits resulting from DSM:

1. *System* - Avoided future infrastructure and related costs, reduced fuel costs, and contribution to achieving environmental and emissions restrictions. All customers receive these benefits.

2. *Class* - When customers within a class participate, the whole class benefits by a reduction in their cost of service allocation, even those who do not actively participate.

3. *Participation* - Customers who are able to participate in DSM programs can lower their own electricity usage and therefore their costs.

The recovery of DSM costs from customers should reflect the level of benefit received by customer classes. Those customer classes who receive the most benefit (i.e., in all three categories) would bear the most responsibility to contribute to the costs. A customer class that receives only system benefits would contribute to the costs accordingly despite not directly participating in programs. Given the nature of DSM programs and benefits it is not possible to precisely calculate and allocate costs based upon these various benefits.

Allocation of DSM Program Costs:

System benefits are allocated to all applicable customer classes in accordance with the Cost of Service Study (COSS) methodology reflecting allocation of generation rate base as per the most recent rate case decision.

Once system benefits have been allocated, the remaining costs relate to the class and participation benefits. These costs are assigned to the class(es) participating in the DSM programs in proportion to amounts invested in each class.

Method:

- Step 1 – Allocate the system benefits to all applicable customer classes, as 25% of the total Approved DSM program costs, in accordance with the COSS methodology per the most recent rate case decision.

- Step 2 – Allocate the class and participation benefits by directly assigning 75% of the DSM

investment identified for each participating customer class.

- Step 3 – Add the amounts from Step 1 and Step 2 to obtain the total amount to be recovered from each class.

- Step 4 - For NS Power bundled service customers, divide the total amount to be recovered from each class by the anticipated electricity sales for the class to derive the required program cost recovery for each class for the upcoming year.

- Step 5 - For customers taking service in the Wholesale or Renewable to Retail markets, recovery of DSM costs will be direct billed in accordance with the customer's class energy bill if served by NS Power under its bundled service offerings.

- Step 6 – Annually, true up the class and participation benefits by customer class, based upon actual experience in the 2 years prior to the current PCR year.

Conditions:

- For bundled service customers, this approach applies to classes as a whole (not to individual customers).

- This approach applies to total Approved DSM costs.

APPLICABILITY

This schedule is a mandatory rider to all electric rate schedules, except the following tariffs: Wholesale Market Non-Dispatchable Supplier Spill Tariff, the Load Retention Tariff, and the Extra Large Industrial Active Demand Control Tariff.

ADJUSTMENTS

Subject to NS Power making application for recovery of costs through the Storm Cost Recovery Rider (SCRR), this Rider will provide for recovery of actual Level 3 and Level 4 storm costs as defined in the Company's Emergency Services Restoration Plan (ESRP), in excess of the amount of Level 3 and Level 4 storm costs included in NS Power's revenue requirement as approved by the NSUARB.

The Storm Cost Recovery Rider costs include non-capital preparation, response, and restoration related costs including but not limited to: (1) storm preparedness including crew staging and related logistical expenses; (2) incremental NSPI wages, benefits, and overtime pay related to storm recovery; (3) costs of external service providers and mutual aid utilities hired by the Company during restoration efforts; (4) materials and supplies used to repair damaged assets and any associated expenses; and (5) other recoverable expenses, including extra costs for temporary repairs and to expedite the permanent repair of damaged property, and expenses incurred for providing services to customers whose electric service has been interrupted.

The Rider will include a Balance Adjustment (BA) which is a rate class-specific charge that accounts for:

1. Actual annual Level 3 and Level 4 storm costs in excess of the amount approved by the Board for inclusion in the Company's revenue requirement inclusive of the cost of financing. It

remains at the Company's discretion to make an application for recovery of these costs. If initiated, the application will be based on actual results and filed in the following year to be made effective on January 1st of the subsequent year.

Eligible storm costs to be included in the Storm Cost Recovery Rider in any given year cannot exceed 2 percent of that year's forecast retail revenues of the Company. Eligible storm costs in excess of the 2 percent cap will be deferred to the subsequent year's SCRR.

SCRR costs will be allocated to classes and recovered in accordance with the Company's Cost of Service Study. For bundled service customers these will be charged on a per kWh basis. For customers taking service in the competitive Wholesale or Renewable to Retail markets, recovery of storm costs will be direct billed in accordance with the customer's class energy bill if served by NS Power under its bundled service offerings.

RATE for 2025

Tariff	**Storm Riders in cents per kWh [2]**
Domestic Service, Domestic Service Time-of-Day, Domestic Service Time of Use, Domestic Service Critical Peak Pricing	0.374
Small General, Small General Time of Use, Small General Critical Peak Pricing	0.355
General, General Time of Use, General Critical Peak Pricing	0.091
Large General	0.041
Small Industrial	0.098
Medium Industrial	0.059

Large Industrial including Interruptible Rider All customers	0.002
Large Industrial including Interruptible Rider Distribution customers	0.037
Municipal	0.002
Outdoor Recreational Lighting	0.485
Unmetered Services	0.485
Generation Replacement & Load Following	0.000
One-Part Real Time Pricing	0.001
Shore Power	0.100
OATT[1]	0.000

Footnotes

(1) Usage in kWs under OATT
(2) OATT in $/kW

If an SCRR application is required, the Company will endeavor to make its application by April 30th to take effect in the following year for: 1) Actual Level 3 and Level 4 storm costs for the prior year; and 2) Actual SCRR recoveries for the prior year compared to forecast SCCR recoveries in the prior year.

SERVICE DEFINITION

Service under this tariff consists in delivery of supplemental power to partial requirement customers who operate their own dispatchable generation equipment, as approved to be connected to the grid by the Company. The Service has three components.

Generation Replacement Service - Backup supply of power on a best efforts basis where the customer's generation equipment is removed from service due to scheduled maintenance, forced outage, or loss of fuel supply.

Optional Load Following Service – Energy delivery in respect of imbalance between load and generation where customer's generation falls in any given hour below the lower of the established net operating capability or customer's load. Energy delivery under this service is defined as top-up energy.

Spill Service - Hourly generation in excess of the customer's load absorbed by the Company. This excess energy is defined as spilled energy.

Power supplied by the Company to the customer in any given hour above the customer generation, if not below the established net operating capability, is defined as supplementary power and will be billed under applicable full requirement tariff. Customers taking this service will be referred to as "customer-generators".

RATE

Backup Service:

The actual or estimated average time coincident incremental cost of generation including transmission losses for the period service is provided plus 0.500 cents per kWh for additional Operating and Maintenance costs, service charges and Administration & General compensation.

Optional Generation Load Following:

Average incremental cost of generation expressed in cents per kWh as determined by the generation forecast for the rate year plus add on charges as defined for back-up service. This price will be 9.419 cents per kWh.

ENERGY CREDIT

The Energy Credit is equal to the average incremental cost of generation as defined under Optional Generation Load Following.

AVAILABILITY

This tariff is available to:

(a) Customers who have their own qualifying generating facility of not less than 2,000 kW of aggregate capacity, as defined under Special Condition (8), normally used to support their own load;

(b) Energy supplied to Non-Utility Owned Generation sites for purposes of startup and replacement of energy normally supplied from their own generation, where the customer has signed an operating agreement under this tariff schedule.

The following general terms and conditions will apply to the applications.

(1) Energy under the Generation Replacement Service provision will be supplied upon request by the customer. In cases where advance written notification can be given by the customer, such as planned maintenance, the Company will advise the customer in writing of the quoted price which will be based on estimated costs during the period. In an emergency situation where time does not permit advance notification the price will be based upon actual costs until the customer provides written notification of the duration of the taking following which the Company will advise the customer in writing of the quoted price for the remainder of the period.

Energy under the load following section will be supplied either through on-going communication provision such as telemetering (when load fluctuations are involved) or written requests (where application is to a specific level of load).

(2) In the event there is an interruption required by NS Power in order to avoid shortfalls in electric supply, customers taking energy under the Generation Replacement Service or Load Following Service will be the first to be called upon to interrupt energy usage from NS Power.

(3) The customers will reduce their available interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.
Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by the Company, the Company may hold this load as Operating Reserve as required by system conditions. When interruptions are required, the Company will exercise the automated control of the customer's load to interrupt the customer load.

(4) Following interruption, service may only be restored by the customer with approval of the Company.

(5) Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(6) Customers must install metering equipment to monitor the output of the customer's generation. The equipment and installation must be approved by the Company and the costs will be the responsibility of the customer.

SPECIAL CONDITIONS

(1) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation.

Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Any service requirements beyond those provided by a single step-down transformation from transmission voltage must be borne by the customer. The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(5) The Company reserves the right to determine the metering location.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) Qualifying generating facility must meet the following requirements:

(i.) Utilize dispatchable sources of generation.

(ii.) May have more than one generating unit so long as the aggregate manufacturer's nameplate rating is of not less than 2,000 kilowatts and which NSPI has the right to verify through inspection or testing.

(iii.) At the discretion of the customer, the generator may be connected to the grid either at any of the existing points of delivery of purchased power from NS Power or at a separate point if approved by NSPI. If a separate point of delivery is used, all additional costs will be the responsibility of the customer-generator.

(iv.) Generating facility shall meet all applicable safety and performance standards established by Measurement Canada, the Canadian Electrical Code, and NSPI's interconnection guidelines.

GENERATION LOAD FOLLOWING CRITERIA

(1) Two months preceding each tariff year the customer-generator, in conjunction with the Company, shall establish the aggregate net operating capability of its generation equipment for the billing purposes of calculating hourly top-up energy from NS Power during the next tariff year. The net operating capability will be set based upon tests of customer's generation equipment and/or operating records. During a period during which the customer-generator encounters conditions that will result in a temporary significant reduction in generation below the established net operating capability, bill payments under the Load Following service and the other full requirement rate, if applicable, will be set based on adjusted net operating capability reflecting the average generation level during such period. For each billing month of the tariff year the Company will load follow to the equivalent of one hundred (100) percent load factor of the adjusted net operating capability in each hour that the customer generation does not exceed its adjusted net operating capability.

(2) On or before November 7th preceding each tariff year the Company shall apply to the Nova Scotia Utility and Review Board for approval of its forecasted incremental cost of generation for the following tariff year. Such average forecasted incremental cost shall be included in determining the load following rate for the next tariff year and each affected

customer shall be notified.

ONE PART EXTRA HIGH VOLTAGE REAL TIME PRICING TARIFF

DEMAND CHARGE

NIL

ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00am - 11:00pm, non-holiday weekdays): 8.425 ¢/kWh
Off-peak (11:00pm - 7:00am, non-holiday weekdays): 0.793 ¢/kWh
Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Utility and Review Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at transmission voltage of 138 kV or higher and have loads of 2000 KVA or 1800 KW, and over.

SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.

- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the

customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause (1), but agrees to remain interruptible for up to five years as provided for under Availability Clause (5) of the Large Industrial Tariff Interruptible Rider. Within the five year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

POWER FACTOR	CONSTANT	POWER FACTOR	CONSTANT
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	.0500	55-60%	1.2455
70-75%	1.0835	0-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its

load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

DEMAND CHARGE

NIL

ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00am - 11:00pm, non-holiday weekdays): 9.058 ¢/kWh
Off-peak (11:00pm – 7:00am, non-holiday weekdays): 1.156 ¢/kWh
Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Utility and Review Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at transmission voltage of 69 kV and have loads of 2000 KVA or 1800 KW, and over.

SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.
- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause (1), but agrees to remain interruptible for up to five years as provided for under Availability Clause (5) of the Large Industrial Tariff Interruptible Rider. Within the five year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer’s request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

POWER FACTOR	CONSTANT	POWER FACTOR	CONSTANT
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

Schedule D

DEMAND CHARGE

NIL

ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00am - 11:00pm, non-holiday weekdays): 8.903 ¢/kWh
Off-peak (11:00pm – 7:00am, non-holiday weekdays): 2.580 ¢/kWh
Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Utility and Review Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at voltage less than 69 KV and have loads of 2000 KVA or 1800 KW, and over.

SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.

- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause (1), but agrees to remain interruptible for up to five years as provided for under Availability Clause (5) of the Large Industrial Tariff Interruptible Rider. Within the five year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

POWER FACTOR	CONSTANT	POWER FACTOR	CONSTANT
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

SHORE POWER TARIFF

AVAILABILITY

(1) This tariff is available to port authorities of Nova Scotia for the sole purpose of providing port electricity to cruise ships docked in ports to meet their own consumption needs in displacement of the on-board self-generation. The tariff is applicable to electric energy where the regular demand is 2,000 kVA or 1,800 kW, and over.

(2) Customers served under this tariff must accept supply interruption. In the event there is an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

(i.) Generation Replacement and Load Following (GR&LF) Rate
(ii.) Load Retention Tariff
(iii.) Shore Power Tariff
(iv.) Interruptible Rider to the Large Industrial Rate

unless there are technical reasons to alter this sequence specific to the instance.

(3) This is a seasonal tariff available from April 1 to November 30.

ENERGY CHARGE

Energy charges will vary by voltage level of the point of delivery and will be made up of two components.

(1) Annually adjusted fuel cost component which shall be the Company's forecast average annual marginal energy cost as approved for use with the GR&LF tariff and adjusted for line losses at the voltage level of the point of delivery.

(2) A fixed cost adder adjusted concurrent with changes in base cost rates coming into effect as a result of a General Rate Case application.

Base Energy Charge Components	Transmission voltage of 138 kV or higher (cents per kWh)	Transmission voltage of 69 kV (cents per kWh)	Distribution voltage (cents per kWh)
Fuel Cost	9.187	9.276	9.464
Fixed Cost Adder	3.919	4.130	5.461
Total	13.106	13.406	14.926

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer and the customer is served at a transmission voltage level.

SUPPLY INTERRUPTIONS

This is an interruptible service. Before connecting the ship to the shore supply the port authority will request permission from NSPI indicating the expected load and duration for which the power is needed.

The customer will make available suitable contact telephone numbers of a person or persons who are able to disconnect the load within ten minutes. Supply Interruption calls will be made to all customers taking energy under this tariff on an equitable and transparent basis.

This Tariff will be available provided that:

(1) The customer has provided written notice of its desire to take interruptible service.

(2) The customer will reduce its available interruptible system load by the amount requested by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order and must have a designated staff person to answer the dedicated telephone at all times when cruise ships are connected to the utility grid. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rate.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a request to interrupt load will result in penalty charges. The penalty will apply based on the usage of the vessel being served via the Port Authority's equipment following the request to interrupt on the day on which the non-compliance took place.

Penalty for Non-Compliance

All energy served after the 10 minute deadline has expired will be billed at $5.00 per kWh. In addition a fixed charge of $2,000.00 will be applied.

The penalty charge is applicable above and beyond the Port Authority's monthly bill.

SPECIAL CONDITIONS

(1) The Port Authority owns and is responsible for the maintenance and operation of all electrical equipment required for the supply of port electricity to docked ships other than the meters and metering transformers supplied by NSPI. NSPI owns and is responsible for the maintenance of meters and metering transformers installed on the Port Authority premises for the purposes of billing.

(2) The Port Authority will ensure that trained staff is available to operate on-shore interconnection equipment to facilitate the connection, synchronization, disconnection and interruption if needed at all times. Such operators must be available to be contacted by NSPI from a minimum of one hour before connection is required to the time that the ship returns to on board power supply.

(3) The Port Authority will file a two year schedule of expected vessels showing their peak electrical demand before October 31 in a calendar year preceding the cruise ship season.

(4) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(5) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period,

calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

POWER FACTOR	CONSTANT	POWER FACTOR	CONSTANT
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

CUSTOMER CHARGE

The monthly customer charge under this tariff is calculated according to the following formula:

$$\text{Monthly customer charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of customers subscribed} * 12}$$

This charge will be $401.58 month.

DEMAND CHARGE

The demand charge for this service is made up of the following two components:

(1) Annually adjusted demand-related purchased power cost, coming into effect as a result of a Base Cost of Fuel, Fuel Adjustment Mechanism, or General Rate Application.

(2) Demand-related fixed generation cost, coming into effect as a result of a General Rate Application.

Demand Charge Components	$ per kW of billing demand
Demand-related Purchased Power Cost	$4.368
Demand-related Fixed Generation Cost	$2.792
Total	**$7.160**

Contract Demand requirement is defined as the firm demand (kW) requested by the wholesale customer (or aggregate customer group) and agreed to be supplied by NSPI. This may constitute all, or a portion of the demand contracted to be served on a primary basis by a third party supplier.

Billing demand is determined based upon the following formula:

$$\text{Billing demand} = (PR/(1+PR) * \min(CD, CCF * GC)) + (CD - \min(CD, CCF*GC))$$

Where: PR is Planning Reserve (based on NPCC planning criteria, i.e., 20% or as updated)

GC is the third party supplier's generating capacity

(a) For non-dispatchable generation, GC = MSC, the Maximum Spill Capacity as defined in Wholesale Market Non-Dispatchable Supplier Spill Tariff.

(b) For dispatchable generation, GC = the supplier's maximum capacity contracted to provide its wholesale customers' demand

CD is the customer's Contract Demand

CCF is the capacity contribution factor of the third party supplier's generation to the NSPI system, as determined at the beginning of a billing year by NSPI using information provided in accordance with Special Condition (7) of this tariff and in a manner consistent with NSPI's generation planning studies as amended from time to time.

ENERGY CHARGE

The energy charge is made up of the following two components:

(1) Annually adjusted energy-related purchased power and fuel cost, coming into effect as a result of a Base Cost of Fuel, Fuel Adjustment Mechanism or General Rate Application.

(2) Energy-related fixed generation cost, coming into effect as a result of a General Rate Application.

Energy Charge Components	**Cents per kWh**
Energy-related Purchased Power and Fuel Cost	7.926
Energy-related Fixed Generation Cost	2.651
Total	**10.577**

FUEL ADJUSTMENT MECHANISM

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the customer charge plus the demand charge.

AVAILABILITY

The tariff is available to wholesale customers as defined in section 2(d) of the *Electricity Act*, Chapter 25 of the Acts of 2004.

> (d) "wholesale customer" means Nova Scotia Power Incorporated or a municipal utility.

The tariff is applicable to the *scheduled* backup/top-up load of participating customers under the following terms and conditions:

(1) The wholesale customer has provided written notice of its intent to take service under this tariff, clearly identifying the following:

- (a) The Municipal utility or utilities for which service is being requested.
- (b) The year for which service is being requested.
- (c) The contract demand (kW) required for backup and top-up service.
- (d) The portion of the customer's annual load contracted to be supplied by third party suppliers or through self-supply.
- (e) The names, addresses, contact details and supply arrangements associated with contracted third party suppliers.

(2) Backup/top-up service will be subscribed on a minimum 12 month, annual-renewable basis, provided that, if a wholesale customer satisfies the requirement of Special Condition (7)(d), the backup/top-up service required with respect to the wholesale customer's procured capacity which satisfies the requirement of Special Condition (7)(d) shall be subscribed by the customer on a minimum three-year forward basis.

Applications for service with a CCF value greater than zero in the billing demand calculation of the demand charge must be provided annually to NSPI by January 31st of each year, for service applicable to the subsequent year, which would commence January 1st of that subsequent year. Absent extraordinary circumstances, NSPI shall notify the wholesale customer of its decision by March 31st of each year following an application.

Applications for service with a CCF value of zero in the billing demand calculation of the demand charge must be provided to NSPI by no later than September 1st, for service applicable to the subsequent year, which would commence January 1st of that subsequent year. Absent extraordinary circumstances, NSPI shall notify the wholesale customer of its decision within two months of receipt of such an application.

(3) Adequate metering equipment, as dictated by the Generation Interconnection Agreement, must be installed to monitor the generation of any third-party generators selected for use by the wholesale customer. The equipment and installation must be approved by the Company and the costs will be the responsibility of the generator.

SPECIAL CONDITIONS

(1) This tariff is designed for customers supplied and metered at the high side of the transformer at transmission voltage of 69 kV or higher. For customers metered at the low side of the transformer, or at a distribution voltage level, meter readings shall be increased by 1.1% for each transformation between the meter and the transmission voltage.

(2) The charges under this rate do not reflect transmission service costs. Customers taking service under this tariff must also take service under OATT.

(3) For system reasons, NSPI may, at its discretion, deny an application for service from a customer who has not taken service from NSPI in the year prior to the year requested.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(7) Unless the following can be demonstrated by the wholesale customer to the satisfaction of NSPI, the CCF shall be attributed a value of zero in the billing demand calculation of the demand charge:

a. For a third-party generation resource within Nova Scotia (Internal Resource):

i. If the Internal Resource is dispatchable, that it can start up and deliver energy contracted to, but unused by, the wholesale customer to NSPI, if directed to do so by the Nova Scotia Power System Operator (NSPSO), in the event of a resource adequacy need;

ii. If the Internal Resource is non-dispatchable, that it make its full output contracted

to, but unused by, the wholesale customer available to deliver energy to NSPI, in the event of a resource adequacy need;

iii. The Internal Resource will remain available for dispatch, if called upon by the NSPSO, by coordinating with the NSPSO and refraining from taking planned outages during certain critical times of the year, as determined by the NSPSO; and

iv. Any export transactions utilizing energy from the Internal Resource will be recallable by the NSPSO, up to the amount contracted to the wholesale customer, for delivery to the NSPI system in the event of a resource adequacy need.

b. For a third-party generation resource outside of Nova Scotia (External Resource):

i. The energy from the External Resource that is contracted to the wholesale customer will be scheduled and delivered to NSPI in the event of a resource adequacy need;

ii. The capacity from the External Resource that is contracted to the wholesale customer must be associated with one or more specific external resource assets, or be system-backed import capacity supported by the external control area where the capacity will be afforded the same curtailment priority as the external control area's native load, and be available to the NSPSO in the event of a resource adequacy need;

iii. If the capacity from the External Resource that is contracted to the wholesale customer is associated with one or more specific external resource assets, the wholesale customer must provide:

1. The name and location of each external resource asset;
2. For each asset, generator data including documentation of dependable maximum net capacity and NERC Generating Availability Data System data;
3. Documentation demonstrating proof of contractual control of the capacity all the way to each external resource asset providing the capacity; and
4. Letter of attestation or other documentation from the External Resource owner establishing that the capacity from the External Resource is not being used as capacity in any other balancing area.

iv. If the capacity from the External Resource will be supported by the external control area, the wholesale customer must provide:

1. Documentation demonstrating that the import capacity will be supported by the external control area and afforded the same curtailment priority as the external control area's native load.

2. Documentation demonstrating that the External Resource has firm transmission from the specific external resource asset or external control area to the NSPI system.

c. The Internal Resource or External Resource, as applicable, will perform as needed to meet NSPI's reliability requirements.

d. The capacity derived based on the CCF is procured and available to the wholesale customer on a minimum three-year forward basis, unless this requirement is waived by NSPI.

(8) In the event of a failure by the Internal Resource or External Resource, as applicable, to deliver scheduled energy or capacity following a direction to do so by the NSPSO in accordance with Special Condition (7), above, then the wholesale customer will be required to make payment to NSPI of an amount equal to the costs incurred by NSPI to procure or to self-supply the undelivered energy and/or capacity, as applicable, less the energy charge paid by the wholesale customer to NSPI under this tariff with respect to any such undelivered energy and/or capacity, as applicable. If delivery of an Internal Resource or External Resource, as applicable, is affected by circumstances that are inconsistent with the information and/or documentation provided to NSPI pursuant to Special Condition (7), above, then NSPI and the wholesale customer shall attempt to negotiate an adjustment to the CCF for the Internal Resource or External Resource, as applicable. If NSPI and the wholesale customer are unable to agree on an adjustment to the CCF, the matter may be submitted to the Board by either party on an expedited basis for adjudication.

WHOLESALE MARKET NON-DISPATCHABLE SUPPLIER SPILL TARIFF

ADMINISTRATION CHARGE

The monthly administration charge under this tariff is calculated according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{Forecast number of suppliers supplying wholesale customers} * 12}$$

This charge will be $ 2,409.46 per month.

ENERGY CREDIT

Compensation for spill energy delivered to NSPI will be at the Company's forecast average annual marginal energy costs of 8.919 cents per kilowatt hour as approved for use with the GRLF rate.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the administration charge.

AVAILABILITY

This tariff is available for use by, independent non-dispatchable electric generators serving the Wholesale Market. The tariff is applicable to *scheduled* "spill energy", under the following terms and conditions:

(1) "Spill energy" is defined as the scheduled hourly energy forecast to be produced by the supplier above the scheduled hourly energy requirement of their wholesale customer(s). Unscheduled energy produced will be compensated according to OATT imbalance guidelines. Spill compensation under this tariff is limited to the supplier's Maximum Spill Capacity (kW). Maximum Spill Capacity must be approved by NSPI prior to commencement of service. Spill capacity will be reviewed periodically and adjusted as required.

(2) Suppliers must install metering equipment to monitor the output of their generation. Consistent with the Generation Interconnection Agreement, the equipment and installation must be approved by the Company and the costs will be the responsibility of the supplier.

SPECIAL CONDITIONS

(1) Suppliers must meet all conditions set forth in the Generation Interconnection Procedures and Generation Interconnection Agreement.

(2) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(3) The supplier will make all necessary arrangements to ensure that its generation output does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated in the Generation Interconnection Agreement.

In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

ENERGY BALANCING SERVICE

The Energy Balancing Service is a supplemental generation service provided to Licenced Retail Suppliers (LRS) in respect of the Licenced Retail Supplier's RtR Customers utilizing the production from renewable low-impact generators. The service consists of delivery of complementary energy to RtR Customers and reception of surplus generation from qualifying generators. The service is required to be taken in conjunction with Standby Service under the Standby Service Tariff so that the reliability of service to RtR Customers is equivalent to that provided under Bundled Service. For the purposes of this Energy Balancing Service Tariff, hourly LRS load in excess of generation is defined as top-up energy and hourly generation in excess of LRS load is defined as spill energy.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Energy Balancing Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Energy Balancing Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Energy Balancing Service Tariff shall also take service under the OATT, the Standby Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Energy Balancing Service Tariff is based on metered energy quantities, and is independent of the LRS's forecasts. OATT Schedule 4 is not applicable, but the Generation Forecasting Service under Schedule 4A of the OATT is applicable.

(3) The hourly top-up and spill quantities are determined at the delivery point from the transmission system. The hourly top-up quantity equals the excess in each hour, if positive, of the LRS's aggregate customer load adjusted by the addition of distribution losses over the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission losses. The hourly spill quantity

equals the excess in each hour, if positive, of the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission locational losses, as applicable to the geographic zone in which the generating facility is interconnected, over its aggregate customer load adjusted by the addition of distribution losses. The locational loss values will be published by the NS Power System Operator. The aggregate hourly load quantities are determined in accordance with the applicable provisions in the LRS Terms and Conditions.

(4) To qualify for this service, the LRS must ensure that the imbalance between low impact renewable generation and energy consumption over the established compliance period conforms to Section 10 of the Board Electricity Retailers Regulations (Nova Scotia) enacted under the Act.

(5) Maximum Spill Capacity must be approved by NS Power prior to commencement of service and will be limited to a level agreed as being required to provide the contracted annual amount of participating LRS energy. Spill capacity will be reviewed annually and will include the LRS' proposal to mitigate it on a going forward basis. If NS Power is not satisfied with the LRS' proposal, it may impose a limit on hourly production of the LRS's generation portfolio.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS's subscribed} * 12}$$

This charge will be $401.58 per month.

ENERGY CHARGE

Energy charge for top-up service is made up of the following two components:

(1) Annually adjusted fuel cost component based on NS Power's incremental cost of serving the LRS's forecasted incremental top-up load.

(2) Fixed cost adder reflective of fixed cost energy-related generation costs.

Energy Charge Components	Cents per kWh
Fuel Cost	8.919
Fixed Cost Adder	3.264
Total	12.183

The charge is applicable to top-up energy consumed in each hour.

ENERGY CREDIT

8.919 cents per kilowatt hour

The Energy Credit for spill service is set annually and is applicable to spilled energy in each hour.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS's RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Energy Balancing Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Utility and Review Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Energy Balancing

Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff.

STANDBY SERVICE

Standby Service is a supplemental generation capacity service provided to Licensed Retail Suppliers (LRS). The service is provided in combination with Energy Balancing Service under the Energy Balancing Service Tariff. The service has two components:

Capacity adequacy service – fulfillment of the LRS's obligation to provide or pay for its share of firm capacity required to meet adequacy standards of the Nova Scotia electricity system arising from forced and unforced generation outages. Energy delivered during generation outages will be billed under the Energy Balancing Service Tariff.

Top-up capacity service – provision of capacity to support energy delivery through the Energy Balancing Service in respect of imbalance between load and generation.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Standby Service Tariff is applicable to the LRS to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Standby Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and.

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Standby Service Tariff shall also take service under Open Access Transmission Tariff (OATT), the Energy Balancing Service Tariff and the Renewable to Retail Market Transition Tariff.

(2) The service under this Standby Service Tariff is complementary to the generation ancillary services to the Renewable to Retail market under OATT.

(3) The aggregate hourly load quantities are determined at the delivery point from the transmission system, inclusive of distribution system losses, in accordance with the provisions of the LRS Terms and Conditions.

(4) This service is applicable to firm load only.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS's subscribed} * 12}$$

This charge will be $401.58 per month.

DEMAND CHARGE

$3.397 per month, per kilowatt (kW) of monthly standby contract demand.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

DETERMINATION OF MONTHLY STANDBY CONTRACT DEMAND

Monthly Standby Contract Demand (MSCD) in kW is determined using the following formula:

$$MSCD = LWPFD - min\ (LWPFD,\ (\sum_{i=1}^{n} CCi * GCi)/(1+PR))$$

Where:

LWPFD is LRS Winter Peak Firm Demand in respect of each billing month calculated as follows:

$$LWPFD = \sum_{i=1}^{k} (CMPFDi * CMDAFi)$$

"k" is the number of otherwise applicable bundled service rate classes to RtR customers of LRS.

"CMPFDi" is hourly kW Class Monthly Peak Firm Demand of the LRS firm load in each tariff class at the time of system coincident firm load peak in each month at transmission delivery points (i.e. inclusive of distribution system losses). The CMPFD for the unmetered customer class shall be determined by use of research based class load profile data.
"CMDAFi" is the Class Monthly Demand Adjustment Factor applicable to each class as set

out below:

Classes	Jan, Feb, Dec	Mar, Apr	May, June	Jul, Aug, Sep	Oct, Nov
Domestic	1.00	1.27	1.67	2.17	1.47
Small General	1.00	1.21	1.32	1.09	1.28
General	1.00	1.12	1.32	1.05	1.19
Large General	1.00	1.05	1.04	0.78	0.99
Small Industrial	1.00	1.06	1.01	0.94	1.00
Medium Industrial	1.00	1.14	1.08	1.01	1.02
Large Industrial Firm	1.00	1.10	1.03	0.89	1.09
Unmetered	1.00	8.24	7.90	7.68	2.28

"PR" is Planning Reserve (%) (based on Northeast Power Coordinating Council planning criteria, i.e., 20% or as updated)

"CCi" is a capacity contribution factor of LRS' generator to NS Power's system peak as determined by NS Power. The capacity contribution factor may be the subject of periodic adjustment if operating conditions of the generator, such as a prolonged deration, depart from those assumed by NS Power.

"GCi" is the generator capacity dedicated to serving LRS load.

"n" is the total number of LRS' generators including those under contract.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS's RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage

flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Standby Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Utility and Review Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Standby Service Tariff, the Energy Balancing Service Tariff or the Renewable to Retail Market Transition Tariff.

RENEWABLE TO RETAIL MARKET TRANSITION TARIFF
Renewable to Retail

PURPOSE

Pursuant to Section 3G(2) of the Electricity Act (Nova Scotia), this Renewable to Retail Market Transition Tariff (RTT) is designed to recover from Licenced Retail Suppliers (LRS) NS Power's embedded fixed costs and deferred costs, recovered through Bundled Service, which are not otherwise recovered through other tariffs applicable to the LRS or its RtR Customers. For certainty, for the purposes of this RTT, NS Power's embedded fixed costs include, but are not limited to, generation related fixed costs (e.g. depreciation, cost of financing including return on common equity, income tax and OM&G). Deferred costs of NS Power are those costs approved by the Nova Scotia Utility and Review Board (Board) for recovery by NS Power from customers at a future date.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

APPLICABILITY

1) The RTT is applicable to the LRS, and is in addition to (and not in substitution of) any charges owing by the LRS to NS Power under the Open Access Transmission Tariff (OATT), the Standby Service Tariff or the Energy Balancing Service Tariff. A charge under the RTT will only apply to the extent the cumulative amount calculated under the RTT for the calendar year is equal to greater than zero.
2) The RTT employs certain usage determinants and rate components applicable under both the Standby Service Tariff and the Energy Balancing Service Tariff.

3) Energy Charges and Demand Charges (both as set out below) under this RTT include provision for mitigation in respect of forecasted NS Power savings enabled by the LRS's supply of electricity to its RtR Customers. The savings credits will be determined annually on the basis of experience and will be applied on a prospective basis.

4) The Energy Charge under this RTT includes provision for annual adjustment on a prospective basis to account for the forecasted difference between NS Power's average avoided cost by the LRS's supply of electricity and its average system fuel cost. If the average avoided cost exceeds the average system fuel cost, this adjustment will be a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost, this adjustment will be an addition to the Energy Charge.

5) An LRS taking service under this RTT shall also take service under the OATT, the Standby Service Tariff, and the Energy Balancing Service Tariff.

ENERGY CHARGE

Energy charge is made up of the following components:

Energy Charge Components	Cents per kWh
Fixed Cost Adder from Energy Balancing Service Tariff	3.264
Annually Adjusted Energy Savings Credit	0.000
Annual Energy Cost Adjustment	(2.463)
Total	0.802

The Energy Charge is applicable to the LRS's monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the Energy Balancing Service Tariff for that LRS.

DEMAND CHARGE

Demand Charge is made up of two components:

Demand Charge Components	Dollars per kW
Demand Charge from Standby Service Tariff	$3.397
Annually Adjusted Demand Savings Credit	$0.000
Total	$3.397

The Demand Charge is applicable to the LRS's monthly displaced demand on NS Power's system determined as the difference between Winter Peak Firm Demand, in respect of the monthly bill of the LRS, and Monthly Standby Contract Demand, both as determined under the Standby Service Tariff for that LRS. For greater certainty, Winter Peak Firm Demand and Monthly Standby Contract Demand are as set out in the Standby Service Tariff.

SPECIAL CONDITIONS

(1) Nothing contained in this RTT or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this RTT, the Standby Service Tariff or the Energy Balancing Service Tariff.

EXTRA LARGE INDUSTRIAL ACTIVE DEMAND CONTROL TARIFF

The Extra Large Industrial Active Demand Control Tariff (ELIADC) provides a mechanism whereby Port Hawkesbury Paper LP (PHP, the Mill, the Customer) pays the forecast incremental costs of its annual forecast service expressed as a levelized Customer Baseline Load (CBL) plus makes a contribution to utility costs, while providing Nova Scotia Power (NS Power) with control of PHP's load such that NS Power's overall system costs can be reduced and system reliability can be improved for the benefit of all NS Power customers.

AVAILABILITY

(a) This Tariff is applicable to operations at PHP's mill site at Point Tupper, and is premised upon PHP's electricity requirements being exclusively served by NS Power.

(b) In addition to the priority interruptible service load reduction requirements prescribed in this Tariff, PHP's load shall be further managed by NS Power in accordance with the Active Demand Control – Energy Supply Protocols attached as Schedule 1 to this Tariff.

(c) The service voltage shall not be less than 138 kV, line to line, at each delivery point. Service is provided at the supply side of the Mill's transformation equipment. PHP must own the transformation facilities and no transformer ownership credit is applicable.

(d) This Tariff cannot be taken in conjunction with other tariffs unless approved by the Nova Scotia Utility and Review Board (Board).

COST OF ELECTRICITY UNDER THE ELIADC TARIFF

The price paid by PHP for electricity under this Tariff will be based on the forecast incremental cost to serve PHP at an assumed levelized baseline load level, plus an adder to contribute to the reduction of the cost of service to other NS Power customers, less a credit to recognize system savings enabled by PHP's granting Active Demand Control of its load to NS Power. The credit is also intended to incent PHP to assist NS Power in realizing the full potential value of Active Demand Control by allowing PHP to share in the resulting system savings.

The pricing elements comprising the ELIADC are:

- Customer Baseline Energy Charge (CBL Energy Charge)
- Customer Baseline Adder (CBLA)
- Variable Capital Charge
- Active Demand Control Credit

Minimum Payment

The ELIADC Tariff requires that a minimum payment shall be made by PHP in respect of each tariff year, which shall not be less than the sum of:

(a) NS Power's actual total incremental cost of serving PHP during the year (including the cost of fuel and purchased power, line losses, variable operating costs and variable capital costs for NS Power's incremental generation and delivery of electricity to the customer), plus

(b) $4.00 multiplied by the total number of MWh supplied in the year.

Any adjustments required to achieve this minimum payment amount will be determined and charged to PHP after year end.

Customer Baseline Energy Charge and Contribution to Utility Costs

In advance of each tariff year, PHP shall advise NS Power of its forecast annual and monthly energy requirements for the subsequent calendar year, including the anticipated dates and durations of PHP's major scheduled maintenance periods. Upon receipt of such forecast, NS Power will then calculate, in $/MWh, its forecast annual cost to serve PHP at a levelized baseline load level (i.e., the Customer's average demand will be assumed to be the same in each hour after taking into account major scheduled maintenance) to produce the CBL Energy Charge.

The CBL Energy Charge calculation will be inclusive of all incremental, non-capital costs to serve PHP and will assume no economic load shifting (e.g. no reductions in usage in high-cost hours or increased usage in low-cost hours). The CBL Energy Charge will include the forecast cost of fuel and purchased power, line losses, and variable operating costs for NS Power's incremental generation and delivery of electricity to PHP. The CBL Energy Charge will form the basis of the ELIADC Energy Charge for the upcoming calendar year.

A CBL Adder **(**CBLA**)** will be calculated with reference to the forecast CBL Energy Charge. As the forecast CBL Energy Charge ($/MWh) decreases, the CBLA increases.

- When the forecast CBL Energy Charge is under $61.75/MWh, the CBLA is calculated as 75 percent of the difference between the forecast CBL and $61.75/MWh, plus $1/MWh.
- When the forecast CBL Energy Charge is at or over $61.75/MWh, the difference between the forecast CBL Energy Charge and $61.75/MWh is assigned a value of zero and the CBLA is calculated as $1/MWh.

The CBL Energy Charge and the associated CBLA shall be submitted for Nova Scotia Utility and Review Board (Board) approval on an annual basis as part of the annual proceeding by which NS Power's Annually Adjusted Rates are established.

In addition to the CBL Energy Charge and CBLA, PHP will pay a Variable Capital Charge (VCC) for NS Power's incremental generation and delivery of electricity to PHP in the amount of $3.34/MWh.

In summary, the Tariff energy charge per MWh will be calculated as follows:

$$ELIADC\ Energy\ Charge = CBL\ Energy\ Charge + CBLA + VCC$$

ELIADC ENERGY CHARGE

The ELIADC Energy Charge is $100.34 per megawatt-hour.

INTRA-YEAR MODIFICATIONS TO THE CBL ENERGY CHARGE

NS Power will utilize its established forecasting methodology to determine the CBL Energy Charge. PHP will undertake commercially reasonable efforts to accurately forecast its energy usage.

If, during any year, certain circumstances, such as those described in the next paragraphs, change significantly resulting in a material impact on the appropriate CBL Energy Charge to be paid by PHP during the year, NS Power may, upon approval of the Board, revise the CBL Energy Charge on a prospective basis.

In recognition that the calculation of the CBL Energy Charge for 2020 may be materially impacted if there are delays to the start date of deliveries of the NS Block energy import beyond June 1, 2020, if NS Power determines that any such delay will have a material impact on the appropriate CBL Energy Charge to be paid by PHP for 2020, then the CBL Energy Charge will be subject to recalculation pursuant to this provision.

Additional circumstances which, if changed significantly, would warrant reassessment of the CBL Energy Charge could include, but are not limited to:

(a) It becomes apparent that the CBL Energy Charge plus the CBLA plus the Variable Capital Charge will not result in the recovery of the actual incremental cost to serve plus $4/MWh;

(b) Material and unexpected change in the cost of generation as compared to the CBL Energy Charge calculation;

(c) Material and unexpected increased electricity consumption by PHP during the year, such as significant physical plant modification (as signified by a specific capital

expenditure beyond normal annual capital spending), a change in product line or a material non-forecast change in product demand; and

(d) Material and unexpected decrease in electricity consumption by PHP during the year (such as due to plant shutdowns, labour issues, or market downtime).

If PHP and NS Power are unable to agree on the required changes to the CBL Energy Charge as a result of any of the above modifications, the matter may be submitted to the Board by either party on an expedited basis for adjudication. Revisions to the CBL Energy Charge will not change the Minimum Payment to be made by PHP.

ACTIVE DEMAND CONTROL AND SCHEDULE VARIANCE

NS Power shall be entitled to actively manage PHP's load in accordance with the terms and conditions set out in the Active Demand Control – Energy Supply Protocol attached as Schedule 1 to this Tariff.

Annually, NS Power shall report to the Board to confirm the dollar value of system savings that have been achieved through Active Demand Control of PHP's load under the Protocol, taking account of the impacts of any variances by PHP from the dispatch schedules issued to it by NS Power and any adjustments arising from schedule variances if required. NS Power shall endeavor to submit this report no later than 60 days after the end of a tariff year.

PHP will be entitled to a credit equal to 25 percent of the cost differential between the CBL Energy Charge and the actual annual cost to serve PHP during the given tariff year. Such payments to the Customer will be made via an annual lump sum payment.

TERM

The initial term of this Tariff is 2020-2023 inclusive, unless revised per a Decision of the Nova Scotia Utility and Review Board (Term). Prior to the end of the initial term, NS Power or PHP may apply to the Board for approval of a subsequent term for this Tariff, including the approval of the pricing elements of the Tariff to be applied during the subsequent term.

REOPENER

If, at any time during the Term, NS Power or PHP determines that the ELIADC Tariff is not working effectively, the parties shall work together to try to resolve any such concerns. If the parties cannot resolve such concerns, either party may apply to the Board to adjust the Tariff,

or the components thereof, on a prospective basis. If necessary, and to protect customers, the Board may grant such approval on an expedited basis. Following any adjustment, PHP would be provided the opportunity to determine whether to remain on the Tariff.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge is not applicable to PHP, and PHP will have no standing to participate in DSM-related proceedings.

FUEL ADJUSTMENT MECHANISM (FAM)

No FAM charges or credits shall be applicable to PHP, and PHP will have no standing to participate in FAM-related processes or proceedings unless it is proposed that a FAM-related charge be assessed against PHP or unless any such process or proceeding specifically deals with an issue that can directly impact on NS Power's incremental electricity costs.

MINIMUM LOAD REQUIREMENT

NS Power will withdraw the availability of this tariff, if, on a consistent basis, PHP is not maintaining a regular demand of 25,000 kVA.

INTERRUPTIBILITY

The Mill will reduce its load by, at a minimum, the amount requested by NS Power within 10 minutes of such request by NS Power. Following such interruption, service may only be restored by the Mill with the approval of NS Power.

PHP will make available suitable contact telephone numbers of a person or persons who are able to interrupt the required load within ten minutes.

Load interruption calls will be made to PHP in advance of all such calls to NS Power's Large Industrial Interruptible Rider customers. Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by NS Power, NS Power may hold this load as Operating Reserve as required by system conditions. When interruptions are required, NS Power will exercise the automated control of the customer's load to interrupt the customer load.

PHP is expected to comply with all calls for interruption. Failure to comply in whole or in part with a request to interrupt load will result in penalty charges, payable within 15 business days unless such penalty payment is being contested in good faith. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge will be equal to the amount of the applicable formula cost for energy taken under this Tariff effective at that time for the consumption used in the month.

The Performance Penalty which is based on PHP's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual demand (above that required by the interruption request) remaining in the third interval directly following two complete 5-minute intervals after the interruption call was delivered by telephone call.

"B" is PHP's average demand in excess of the compliance level based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A".

The total penalty will not exceed two times the cost of the formula amount, effective at that time for the consumption used in that month.
Should PHP fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

Conversion of Interruptible Load to Firm

Should PHP desire to be served under any applicable firm service tariff, a five-year advance written notice must be given to NS Power so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service received by NS Power. NS Power may, however, permit an earlier conversion. If PHP desires to return to interruptible service in the future, PHP may convert to an interruptible service tariff following two years of service under the firm tariff schedule. NS Power may permit an earlier conversion from firm to interruptible service.

Order of Interruptibility

In the event an interruption call is required in order to avoid shortfalls in system electricity supply, interruptible load will be called upon to provide capacity to NS Power in the following order:

1. Generation Replacement and Load Following (GRLF) Tariff;
2. Extra Large Industrial Active Demand Control Tariff;
3. Shore Power Tariff;
4. Interruptible Rider to the Large Industrial Tariff.

In situations in which load of the customer under this Tariff is held as Operating Reserve, NS Power may change the above order of interruption by interrupting Large Industrial Interruptible Rider Tariff customers whose load is not held as Operating Reserve before interrupting the Customer.

MAINTAIN SYSTEM INTEGRITY

PHP will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

SECURITY FOR PAYMENTS

NS Power shall invoice PHP weekly, and PHP shall pay the billed amount net 7 days. As security for payment, PHP shall provide NS Power a letter of credit from time to time. The form, amount, and issuer of the letter of credit will be satisfactory to NS Power. To the extent that a letter of credit introduces a lag time and there are additional costs to NS Power, these will be paid by PHP not NS Power or its customers.

SEPARATE SERVICE AGREEMENT

NS Power reserves the right to have a separate service agreement if, in the opinion of NS Power, issues not specifically set out herein must be addressed for the ongoing benefit of NS Power and its customers.

POWER FACTOR CORRECTION

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total Mill load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the CBL Energy Charge:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

METERING COSTS

Metering will normally be at the low voltage side of the transformer and, for measurement and, where applicable, billing purposes, meter readings will be increased by 1.1%. Should the Mill's requirements make it necessary for NS Power to provide primary metering, PHP will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by PHP in connection with service under this Tariff shall be paid for by PHP as a capital contribution.

Schedule "A"

LOAD RETENTION TARIFF

DEMAND CHARGE

To be determined as specified in Special Condition (1).

ENERGY CHARGE

To be determined as specified in Special Condition (1).

AVAILABILITY

(1) This rate shall be granted only in circumstances where it can be shown that:

- The customer's option to use a supply of power and energy (alternate supply) other than NSPI's is both technically and economically feasible, or the rate is required to respond to the competitive challenge of business closure due to economic distress; and

- Retaining the customer's load, at the price offered by this rate, is better for other electric customers than losing the customer load in question; and

- The revenue from service to a customer under this rate shall be greater than the applicable incremental cost to serve such customer and shall make a significant positive contribution to fixed costs.

The procedure for establishing that this test is satisfied is outlined in Attachment A.

(2) This rate shall be available only to customers who have a minimum load of and/or who are considering an alternate supply of at least 2000 KVA or 1800 KW. Where the rate is required to respond to the competitive challenge of business closure due to economic distress this rate shall be available only to Extra-Large Industrial customers.

(3) The customer shall apply in writing to take service under this rate.

(4) This rate shall be available only to customers whose electricity needs, at the date of application, are being supplied by NSPI and have been supplied by NSPI for at least two consecutive years at the time of the request. It is not available for new load.

MINIMUM LOAD REQUIREMENT

All customers must agree to maintain a minimum level of load while taking service under the rate, subject to (i) any terms or conditions relating to supply interruption that may be outlined in the

LOAD RETENTION TARIFF

pricing conditions of the rate, (ii) the customer's requirement to take downtime for maintenance purposes and (iii) market downtime, labour disruption and other matters beyond the reasonable control of the customer.

SECURITY FOR PAYMENT OF ACCOUNT

A customer taking service under this rate must provide security for payment of the customer's account, regardless of payment history. Appropriate security shall be satisfactory to Nova Scotia Power Inc. Acceptable security will be described in the pricing of the rate, and may be revised or updated from time to time upon approval of the UARB.

DISCONNECTION OF ELECTRIC SERVICE

In the event of non-payment, NSPI may disconnect a customer on two business days' notice. In the event of a dispute under the tariff, the complaint will be made directly to the Board for resolution, as opposed to the Dispute Resolution Officer.

SPECIAL CONDITIONS

(1) The price, terms and conditions (including any modification in special conditions associated with the rate(s) under which the customer purchased power and energy prior to taking service under this rate) shall be established jointly by NSPI and the customer, following the procedure outlined in Attachment A.

(2) The price, terms and conditions offered under this rate shall be determined on a customer by customer basis.

(3) The price, terms and conditions offered under this rate shall be submitted by NSPI to the UARB for approval.

LOAD RETENTION TARIFF

ATTACHMENT A

This attachment outlines procedures by which the requirements of Availability Clause (1) and Special Condition (1) are to be satisfied.

(1) The customer shall apply in writing to take service under this rate, outlining the available alternate supply option or the potential for closure due to economic distress and the rationale for seeking service under the load retention rate.

(2) Upon written application by a customer to take service under this rate which meets the requirements of clause (1) above, the UARB shall direct that NSPI conduct a screening to determine whether the implementation of these procedures is warranted.

(3) Subject to (2), NSPI and the customer shall proceed to implement these procedures and establish a load retention price, with appropriate terms and conditions.

(4) Should there be disagreement between NSPI and the customer with respect to the decision to proceed, the customer may ask the UARB to adjudicate.

(5) These procedures shall be applied on a customer by customer basis.

(6) To protect confidential NSPI and customer data, none of the data or analysis used in the implementation of these procedures, nor any results thereof, including the recommended price, terms and conditions, shall be required to be publicly disclosed.

(7) The economic feasibility of the customer's option to supply some or all of its own load shall be established where it can be shown that under reasonable assumptions the cost of electricity to the customer from that option is expected to be lower than the cost to the customer of continuing to purchase electricity from NSPI.

(8) The cost to the customer of the alternate supply shall reflect all appropriate factors, including but not limited to:

- Capital costs
- Fixed and Variable Operating costs
- Fuel costs (short and long term, contracts, etc.)
- Ancillary Services costs (electric)
- Steam production and steam backup costs (where appropriate)
- Contributions-in-aid of construction (where NSPI's system must be modified to accommodate the customer's generator)
- Expected Service Life

LOAD RETENTION TARIFF

- Salvage Value
- Electric sales/purchases (where the customer's generator output does not match customer requirements)
- Depreciation and/or Capital Cost Allowance
- Taxes
- Appropriate return

(9) The technical feasibility of the customer's alternate supply shall reflect all appropriate factors, including but not limited to:

- Technology maturity and proven performance level
- Site specific considerations (space requirements, availability of cooling water, fuel handling, etc.)
- Environmental acceptability (air emissions, solid waste management, etc.)
- Modifications to NSPI's transmission and/or distribution system to accommodate the new generation and/or to supply ancillary services.
- Metering systems
- Where cogen is involved, compatibility of steam versus electric requirements.

(10) If the customer is applying for a load retention rate on the basis of economic distress, the customer shall provide NSPI and the UARB proof of economic distress, the adequacy of which shall be determined by the UARB prior to approving any proposed rate, including:

- Current and historical financial information for a minimum of at least three (3) fiscal years of the customer
- Evidence of activities undertaken by the customer in the last three (3) years to reduce costs
- Affidavit of a senior executive of the customer or its parent indicating the need for the requested load retention rate. Whether the affidavit is provided by an executive of the customer or the parent must be consistent with whether it will be the customer or parent who will make the decision to leave NSPI's system in the absence of the load retention rate. Further the affidavit should include
  - An analysis of the market in which the customer operates
  - Identification of the factors other than electricity costs that are contributing to the economic hardship
  - The customer's plan to address the above factors
  - An estimate of the electricity price that could alleviate the economic hardship
  - An estimate of the probability that the customer will leave NSPI's system if the requested load retention rate is not granted

LOAD RETENTION TARIFF

- Such other information as reasonably requested by NSPI or the UARB.

(11) The impact on NSPI's other customers of losing the customer load in question, shall be determined using NSPI's forecasting and planning models (as appropriate) to compare scenarios that include either the customer's move to an alternate supply or cessation of operations, as the case may be, with scenarios that assume the customer continues to be supplied by NSPI.

(12) Where the impact on NSPI's other customers can be mitigated by offering the customer in question a load retention rate, NSPI and the customer shall determine an appropriate rate for the customer. This shall include the price (which may be formula-driven), and any other terms and conditions, including (where relevant) a suggested term and any appropriate renewal guidelines.

Note: For certainty, all capitalized terms shall, unless otherwise defined herein, have the meanings ascribed thereto in Distribution Tariff.

APPLICABILITY

This schedule provides charges for Distribution System Access applicable to distribution-connected RtR Customers receiving supply of renewable low-impact electricity from a Licenced Retail Supplier as provided for under the Electricity Act (Nova Scotia).

CHARGES

Domestic Service, Domestic Service Critical Peak Pricing, Domestic Service Time of Use	**Customer Charge**	**Distribution Charge**	**Minimum Monthly Charge**
	$/month	**¢/kWh**	**$/month**
Effective February 2, 2023	19.17	1.786	19.17
Effective January 1, 2024	19.17	1.852	19.17
Domestic Service Time-of-Day	**Customer Charge**	**Distribution Charge**	**Minimum Monthly Charge**
	$/month	**¢/kWh**	**$/month**
Effective February 2, 2023	19.17	1.786	19.17
Effective January 1, 2024	19.17	1.852	19.17
Small General, Small General Critical Peak Pricing, Small General Time of Use	**Customer Charge**	**Distribution Charge**	**Minimum Monthly Charge**
	$/month	**¢/kWh**	**$/month**
Effective February 2, 2023	21.28	2.037	21.28
Effective January 1, 2024	21.28	2.107	21.28

General, General Critical Peak Pricing, General Time of Day	**Demand Charge**	**Minimum Monthly Charge**	**Transformer Ownership Credit**
	$/kVA	**$/month**	**$/kVA**
Effective February 2, 2023	5.060	21.28	-0.32
Effective January 1, 2024	5.150	21.28	-0.32
Large General	**Demand Charge**	**Minimum Monthly Charge**	**Transformer Ownership Credit**
	$/kVA	**$/month**	**$/kVA**
Effective February 2, 2023	4.782	21.28	-0.32
Effective January 1, 2024	4.872	21.28	-0.32

Small Industrial	**Demand Charge**	**Minimum Monthly Charge**	**Transformer Ownership Credit**
	$/kVA	**$/month**	**$/kVA**
Effective February 2, 2023	5.143	21.28	-0.32
Effective January 1, 2024	5.178	21.28	-0.32
Medium Industrial	**Demand Charge**	**Minimum Monthly Charge**	**Transformer Ownership Credit**
	$/kVA	**$/month**	**$/kVA**
Effective February 2, 2023	3.573	21.28	-0.32
Effective January 1, 2024	3.639	21.28	-0.32
Large Industrial	**Demand Charge**	**Minimum Monthly Charge**	**Transformer Ownership Credit**
	$/kVA	**$/month**	**$/kVA**
Effective February 2, 2023	1.975	21.28	-0.32
Effective January 1, 2024	2.118	21.28	-0.32

Outdoor Recreational Lights	**Distribution Charge**
	¢/kWh
Effective February 2, 2023	3.709
Effective January 1, 2024	3.747

Unmetered	**Demand Charge**	**Minimum Monthly Charge**
	$/kVA	**$/month**
Effective February 2, 2023	14.006	21.28
Effective January 1, 2024	14.166	21.28
Unmetered - Miscellaneous Small Loads	**Demand Charge**	**Minimum Monthly Charge**
	$/kVA	**$/month**
Effective February 2, 2023	14.006	21.28
Effective January 1, 2024	14.166	21.28

Note 1. Demand Charges and credits are applicable to kilovolt-ampere of maximum (kVA) demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven months regardless whether service was taken under the bundled or unbundled service.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The same maximum per kWh charges and minimum bills will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above.

AVAILABILITY

The same Availability conditions will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above, saving and excepting the Interruptible Rider to the Large Industrial Tariff (Rate Code 25) which will not apply.

SPECIAL CONDITIONS

The same Special Conditions will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above, saving and excepting the Interruptible Rider to the Large Industrial Tariff (Rate Code 25) which will not apply.

STREET AND AREA LIGHTING RATES

Note: Rates listed under 2023 and 2024 shall be in effect starting February 2 and January 1 respectively

(1) INCANDESCENT

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Month.**	**2023**	**2024**	
001	300 and less	97	8.66	9.04	
002	Greater than 300	154	11.18	11.59	

b) Operating Only

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Month.**	**2023**	**2024**	
003	300 and Less	97	10.62	10.96	

(2) MERCURY VAPOUR

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
100	100	43	7.81	8.15	
101	125	52	8.19	8.54	
102	175	69	8.66	9.01	
103	250	97	10.62	10.96	
104	400	154	13.09	13.47	
105	700	260	18.82	19.23	
106	1000	363	24.26	24.71	
107	250	212	11.28	11.61	Continuous Operation

b) Operating and Maintenance Only

Rate Code	Watts	kWh/Mo.	Per Month ($)		Other
			2023	2024	
201	125	52	3.08	3.09	
202	175	69	3.57	3.59	
203	250	97	4.75	4.78	
204	400	154	7.14	7.20	
205	700	260	11.59	11.71	
206	1000	363	15.92	16.09	

c) Operating Only

Rate Code	Watts	kWh/Mo.	Per Month ($)		Other
			2023	2024	
301	125	52	2.18	2.21	
302	175	69	2.90	2.93	
303	250	97	4.08	4.12	
304	400	154	6.47	6.54	
305	700	260	10.92	11.05	
306	1000	363	15.25	15.43	

(3) FLUORESCENT

a) Operating, Maintenance and Capital (Full Charge)

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)		other
				2023	2024	
110	24	2	30	7.11	7.43	
111	48	2	85	9.69	10.04	

112	72	2	116	11.49	11.85	
113	72	4	222	17.19	17.57	
114	96	1	47	8.39	8.73	
115	72	1	60	8.53	8.87	
116	48	4	166	13.70	14.08	

b) Operating and Maintenance Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)		Other
				2023	2024	
213	72	4	222	10.68	10.74	
214	96	1	47	3.32	3.31	
215	72	1	60	3.87	3.86	
216	48	4	166	8.32	8.36	
217	48	1	49	3.41	3.39	
218	48	2	85	4.92	4.92	

c) Operating Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)		Other
				2023	2024	
330	35	4	47	1.97	2.00	

(4) FLUORESCENT CROSSWALK

a) Continuous Burning - Operating Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)		Other
				2023	2024	
117	72	4	486	9.32	9.43	
118	24	2	66	1.27	1.28	
119	48	4	364	6.98	7.06	
120	96	2	254	4.87	4.93	
150	96	4	613	11.76	11.90	

b) Photocell Operation - Operating Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)		Other
				2023	2024	
310	24	2	30	1.26	1.27	
311	48	4	166	6.97	7.05	
312	72	2	116	4.87	4.93	
313	72	4	222	9.33	9.43	
314	96	1	47	1.97	2.00	
315	72	1	60	2.52	2.55	
350	96	4	280	11.77	11.90	

(5) LOW PRESSURE SODIUM

a) Operating, Maintenance and Capital (Full Charge)

Rate Code	Watts	kWh/Mo.	Per Month ($)		Other
			2023	2024	
130	135	60	12.67	12.93	
131	180	80	16.31	16.54	
132	90	45	12.04	12.29	

b) Operating and Maintenance Only

Rate Code	Watts	kWh/Mo.	Per Month ($)		Other
			2023	2024	
231	180	80	5.38	5.37	

c) Operating Only

Rate Code	Watts	kWh/Mo.	Per Month ($)		Other
			2023	2024	
331	180	80	3.36	3.40	

(6) **HIGH PRESSURE SODIUM**

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
121	250	100	10.22	10.59	
122	400	150	12.45	12.83	
123	70	32	7.15	7.49	
124	100	45	7.73	8.07	
125	150	65	8.76	9.11	
126	100	99	8.41	8.74	Continuous Operation

b) Operating and Maintenance Only

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
221	250	100	4.87	4.91	
222	70	32	2.01	2.02	
223	100	45	2.56	2.57	
224	150	65	3.40	3.42	

c) Operating Only

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
321	250	100	4.20	4.25	
322	70	32	1.34	1.36	
323	100	45	1.89	1.91	
324	150	65	2.73	2.76	
326	400	150	6.30	6.37	
327	500	183	7.69	7.78	
328	1000	363	15.25	15.43	
329	1500	500	21.01	21.25	

(7) METALLIC ADDITIVE

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
140	400	150	13.36	13.73	
141	1000	360	24.63	25.05	
142	250	100	11.74	12.07	
143	150	67	10.36	10.67	
144	100	50	9.64	9.94	

b) Operating Only

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
341	1000	360	15.13	15.30	
342	400	150	6.30	6.37	
343	250	100	4.20	4.25	
344	175	75	3.15	3.19	
345	150	67	2.82	2.85	
346	100	50	2.10	2.12	

(8) LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
530	4.6	3	0.06	0.07	Non-Continuous
531	7.5	5	0.11	0.11	Continuous

(9) LIGHT EMITTING DIODE (LED) – Operating Only

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
532	44	15	0.63	0.64	
533	66	22	0.92	0.93	
534	88	29	1.22	1.23	

535	92	31	1.30	1.32	
536	105	35	1.47	1.49	
537	173	57	2.40	2.42	
538	44	15	0.63	0.64	
539	110	37	1.55	1.57	
540	65	22	0.92	0.93	
541	55	18	0.76	0.76	
542	83	28	1.18	1.19	
543	48	16	0.67	0.68	
544	72	24	1.01	1.02	
546	43	14	0.59	0.59	
547	50	17	0.71	0.72	
548	53	18	0.76	0.76	
549	80	27	1.13	1.15	
550	200	67	2.82	2.85	
551	60	20	0.84	0.85	
552	70	23	0.97	0.98	
553	87	29	1.22	1.23	
554	173	58	2.44	2.46	
555	35	12	0.50	0.51	
556	51	17	0.71	0.72	
557	172	57	2.40	2.42	
558	91	30	1.26	1.27	
559	42	14	0.59	0.59	
560	13	4	0.17	0.17	
561	8	3	0.13	0.13	
562	150	50	2.10	2.12	
563	60	20	0.84	0.85	
564	28	9	0.38	0.38	
565	86	29	1.22	1.23	
567	100	33	1.39	1.40	
569	143	48	2.02	2.04	
570	200	67	2.82	2.85	
572	250	83	3.49	3.53	
573	52	17	0.71	0.72	
574	140	47	1.97	2.00	

575	185	62	2.61	2.63	
576	95	32	1.34	1.36	
578	75	25	1.05	1.06	
579	138	46	1.93	1.95	
582	54	18	0.76	0.76	
583	175	58	2.44	2.46	
584	46	15	0.63	0.64	
585	69	23	0.97	0.98	
586	108	36	1.51	1.53	
587	158	53	2.23	2.25	
589	48	16	0.67	0.68	
590	90	30	1.26	1.27	
591	240	80	3.36	3.40	
592	135	45	1.89	1.91	
593	30	10	0.42	0.42	
594	133	44	1.85	1.87	
595	55	18	0.76	0.76	
596	52	17	0.71	0.72	
597	41	14	0.59	0.59	
598	68	23	0.97	0.98	
599	117	39	1.64	1.66	

(10) LIGHT EMITTING DIODE (LED) – Operating, Maintenance & Capital Only (full charge)

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
615	44	15	8.67	8.90	
616	55	18	8.80	9.02	
623	28	9	8.42	8.64	
624	50	17	8.75	8.98	
625	72	24	9.05	9.28	
626	100	33	9.43	9.66	
627	200	67	10.86	11.11	

(11) LIGHT EMITTING DIODE (LED) – Operating, Maintenance & Capital (full charge)

			Per Month ($)		Other
Rate Code	**Watts**	**kWh/Mo.**	**2023**	**2024**	
724	55	18	6.75	7.02	
740	190	63	15.02	15.15	
741	261	87	17.38	17.48	
742	124	41	11.87	12.05	
743	84	28	10.81	10.98	

Nova Scotia Power

Open Access Transmission Tariff (OATT)

Schedules 1 to 10

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Open Access Transmission Tariff (OATT) Schedules

Proposed versions

Schedule 1	Scheduling, System Control and Dispatch Service
Schedule 2	Reactive Supply and Voltage Control from Generation Sources Service
Schedule 3	Regulation and Frequency Response Service
Schedule 5	Operating Reserve – Spinning Reserve Service
Schedule 6	Operating Reserve – Supplemental Reserve Service
Schedule 7	Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service
Schedule 8	Non-Firm Point-to-Point Transmission Service
Schedule 9	Real Power Loss Factors
Schedule 10	Network Integration Transmission Service Rate

Note: OATT Schedules 4 and 4A are not proposed to be revised in this Application.

This service is required to schedule the movement of power through, out of, within, or into an Operating Area. This service can be provided only by the operator of the Operating Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Operating Area operator. The charges, payable monthly, for Scheduling, System Control and Dispatch Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

1) Point-to-Point Transmission Service:

2023		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$4,852.88	/MW of Reserved Capacity per year
Monthly	$404.41	/MW of Reserved Capacity per month
Weekly	$93.32	/MW of Reserved Capacity per week
On-Peak Daily	$18.66	/MW of Reserved Capacity per day
Off-Peak Daily	$13.30	/MW of Reserved Capacity per day
On-Peak Hourly	$1.17	/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.55	/MW of Reserved Capacity per hour

2024		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$4,852.88	/MW of Reserved Capacity per year
Monthly	$404.41	/MW of Reserved Capacity per month
Weekly	$93.32	/MW of Reserved Capacity per week
On-Peak Daily	$18.66	/MW of Reserved Capacity per day
Off-Peak Daily	$13.30	/MW of Reserved Capacity per day
On-Peak Hourly	$1.17	/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.55	/MW of Reserved Capacity per hour

On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

2) Network Integration Transmission Service:

For 2023, $360.35/MW of Network Integration Transmission Service per month
For 2024, $360.35/MW of Network Integration Transmission Service per month

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Operating Area where the Transmission Provider's transmission facilities are located) under the control of the operating area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission system. The Transmission Customer must purchase this service from the Transmission Provider or the Operating Area operator. The charges, payable monthly, for such service are based on the rates set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Operating Area operator.

1) Point-to-Point Transmission Service

2023		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,249.91	/MW of Reserved Capacity per year
Monthly	$187.49	/MW of Reserved Capacity per month
Weekly	$43.27	/MW of Reserved Capacity per week
On-Peak Daily	$8.65	/MW of Reserved Capacity per day
Off-Peak Daily	$6.16	/MW of Reserved Capacity per day
On-Peak Hourly	$0.54	/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.26	/MW of Reserved Capacity per hour

2024		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,249.91	/MW of Reserved Capacity per year
Monthly	$187.49	/MW of Reserved Capacity per month
Weekly	$43.27	/MW of Reserved Capacity per week
On-Peak Daily	$8.65	/MW of Reserved Capacity per day
Off-Peak Daily	$6.16	/MW of Reserved Capacity per day
On-Peak Hourly	$0.54	/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.26	/MW of Reserved Capacity per hour

On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

2) Network Integration Transmission Service:

For 2023, $170.59 /MW of Network Integration Transmission Service per month.

For 2024, $170.59 /MW of Network Integration Transmission Service per month.

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Operating Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The charges, payable monthly, for Regulation and Frequency Response Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass- through of the costs charged to the Transmission Provider by that Operating Area operator.

1) Regulation (Point-to-Point Transmission Service)

The minimum period for which this service is available from the Transmission Provider is one day.

2023		
Regulation (Point-to-Point Transmission Service)		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,620.80	/MW of Reserved Capacity per year
Monthly	$218.40	/MW of Reserved Capacity per month
Weekly	$50.40	/MW of Reserved Capacity per week
Daily	$7.18	/MW of Reserved Capacity per day

2024		
Regulation (Point-to-Point Transmission Service)		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,620.80	/MW of Reserved Capacity per year
Monthly	$218.40	/MW of Reserved Capacity per month
Weekly	$50.40	/MW of Reserved Capacity per week
Daily	$7.18	/MW of Reserved Capacity per day

2) Regulation (Network Integration Transmission Service)

For 2023, $218.40/MW of Network Integration Transmission Service per month.
For 2024, $218.40/MW of Network Integration Transmission Service per month.

3) Load Following (Point-to-Point Transmission Service)

The minimum period for which this service is available from the Transmission Provider is one day.

2023		
Load Following (Point-to-Point Transmission Service)		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$9,489.96	/MW of Reserved Capacity per year
Monthly	$790.83	/MW of Reserved Capacity per month
Weekly	$182.50	/MW of Reserved Capacity per week
Daily	$26.00	/MW of Reserved Capacity per day

2024		
Load Following (Point-to-Point Transmission Service)		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$9,489.96	/MW of Reserved Capacity per year
Monthly	$790.83	/MW of Reserved Capacity per month
Weekly	$182.50	/MW of Reserved Capacity per week
Daily	$26.00	/MW of Reserved Capacity per day

4) Load Following (Network Integration Transmission Service)

For 2023, $790.83/MW of Network Integration Transmission Service per month.
For 2024, $790.83/MW of Network Integration Transmission Service per month.

5) Customer Obligations for Self-Supply and Third-Party Supply

The customer obligation for self-supply or third-party supply of Regulation is equal to 3.5 percent of Reserved Capacity for Point-to-Point Transmission Service and 3.5 percent of the Network Load for Network Integration Transmission Service.

The customer obligation for self-supply or third-party supply of Load Following is equal to 9.1 percent of Reserved Capacity for Point-to-Point Transmission Service and 9.1 percent of Network Load for Network Integration Transmission Service.

SCHEDULE 4: ENERGY IMBALANCE SERVICE

This Schedule 4 is not applicable to Licenced Retail Suppliers.

The Generation Forecasting Service set out in Schedule 4A of the OATT will apply to Licenced Retail Suppliers only and is not applicable to any other Eligible Customer.

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within an Operating Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

For a bilateral schedule of a single load and its single generator, this ancillary service will be applied to the net of the generation and load imbalance. Otherwise, this Ancillary Service will be applied separately to deviations from load schedules and deviations from generation schedules. This ancillary service does not apply to power exported from the Operating Area, which is covered by the Generation Balancing Service of the Standard Generator Interconnection and Operation Agreement.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to

- Respond to transmission, generation or load contingencies.

For the purposes of Energy Imbalance Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Load Energy Imbalance Associated with Point-to-Point or Network Integration Transmission Service:

For each Transmission Customer taking service under Part II or Part III of this Tariff, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

A deviation band of +/- 1.5 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be applied hourly to any net load energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

Parties should attempt to eliminate energy imbalances within the limits of the deviation band within the billing month in accordance to the following:

- For hourly imbalances that arise during peak hours, such imbalances should be eliminated via deliveries or withdrawals during peak hours; and

- For hourly imbalances that arise during non-peak hours, such imbalances should be eliminated via deliveries or withdrawals during non-peak hours.

Net load energy imbalances within the deviation band that have not been eliminated at the end of the billing month will be subject to the charges set below:

- Energy supplied by the Transmission Provider during peak hours to compensate for a net shortfall in peak hours delivery over the billing month will be charged at the average on-peak system marginal cost for the billing month. Energy supplied by the Transmission

Provider during non-peak hours to compensate for a net shortfall in non-peak hours delivery over the billing month will be charged at the average non-peak system marginal cost for the billing month.

- Energy supplied to the Transmission Provider during peak hours as a net excess of the peak hours delivery over the billing month will be purchased by the Transmission Provider at the average on-peak system marginal cost for the billing month. Energy supplied to the Transmission Provider during non-peak hours as a net excess of the non-peak hours delivery over the billing month will be purchased by the Transmission Provider at the average non-peak system marginal cost for the billing month.

Energy imbalances outside of the deviation band are not eligible for elimination and are subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net hourly shortfall in delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Dispatchable Generators:

For Dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Non-Dispatchable Generators

For Non-dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

Energy Imbalances inside a deviation band of +/- 10 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at the hourly system marginal cost in the hour of the deviation.

All deviations from schedule outside of the +/- 10 percent deviation band will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

SCHEDULE 4A: GENERATION FORECASTING SERVICE

This Generation Forecasting Service set out in Schedule 4A of the OATT applies to Licenced Retail Suppliers only and is not applicable to any other Eligible Customer. Generation Forecasting Service addresses the accuracy of generation scheduling by Licenced Retail Suppliers.

This Schedule does not apply to forecasting discrepancies that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Forecast Deviation Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Each Licenced Retail Supplier shall use commercially reasonable efforts to provide accurate schedules and forecasts of production from renewable low-impact generators that are not dispatchable.

To the extent that such schedules or forecasts of hourly production of the aggregate of a Licenced Retail Supplier's RtR generation resources deviate from the actual production for reasons other than those that occur as a result of actions directed by the Operating Area operator the following charges shall apply:

An hourly deviation band of +/- 10 percent of the aggregate hourly scheduled or forecast quantity (with a minimum deviation band of +/- 2 MW) will be applied hourly to any forecast discrepancy that occurs as a result of the Transmission Customer's scheduled transaction(s).

- Hourly forecast discrepancies falling outside the hourly deviation band during peak hours will be charged at 10% of the average on-peak system marginal cost for the billing month.
- Hourly forecast discrepancies falling outside the hourly deviation band during non-peak hours will be charged at 10% of the average non-peak system marginal cost for the billing month.

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The charges, payable monthly, for Spinning Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

1) Point-to-Point Transmission Service

2023		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,034.97	/MW of Reserved Capacity per year
Monthly	$169.58	/MW of Reserved Capacity per month
Weekly	$39.13	/MW of Reserved Capacity per week
Daily	$5.58	/MW of Reserved Capacity per day

2024		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,034.97	/MW of Reserved Capacity per year
Monthly	$169.58	/MW of Reserved Capacity per month
Weekly	$39.13	/MW of Reserved Capacity per week
Daily	$5.58	/MW of Reserved Capacity per day

The minimum period for which this service is available from the Transmission Provider is

one day.

2) Network Integration Transmission Service

For 2023, $169.58/MW of the Network Integration Transmission Service per month.
For 2024, $169.58/MW of the Network Integration Transmission Service per month.

3) Customer Obligations for Self-supply and Third-party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve - Spinning Reserve is equal to 2.0 percent of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service and 2.0 percent of the Network Load for Network Integration Transmission Service.

4) Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

5) Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission

Customers. This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Operating Reserve service will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

Supplemental Reserve Service (also referred to as Contingency Reserve - Supplemental) is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The charges, payable monthly, for Supplemental Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

1) Operating Reserve - Supplemental *(10* minute)

Point-to-Point Transmission Service

The minimum period for which this service is available from the Transmission Provider is one day.

2023		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$4,053.66	/MW of Reserved Capacity per year
Monthly	$337.80	/MW of Reserved Capacity per month
Weekly	$77.96	/MW of Reserved Capacity per week
Daily	$11.11	/MW of Reserved Capacity per day

2024		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$4,053.66	/MW of Reserved Capacity per year
Monthly	$337.80	/MW of Reserved Capacity per month
Weekly	$77.96	/MW of Reserved Capacity per week
Daily	$11.11	/MW of Reserved Capacity per day

Network Integration Transmission Service:

For 2023, $337.80/MW of the Network Integration Transmission Service per month.
For 2024, $337.80/MW of the Network Integration Transmission Service per month.

Customer Obligations for Self-supply and Third-Party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve - Supplemental Reserve will be equal to 8.3 percent of Reserved Capacity for Point-to-Point Transmission Service and 8.3 percent of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

2) Operating Reserve - Supplemental *(30* minute):

Point-to-Point Transmission Service

The minimum period for which this service is available from the Transmission Provider is one day.

2023		
Point-to-Point Transmission Service		
Delivery Period	**Charge($)**	
Yearly: One twelfth of	$3,435.56	/MW of Reserved Capacity per year
Monthly	$286.29	/MW of Reserved Capacity per month
Weekly	$66.07	/MW of Reserved Capacity per week
Daily	$9.42	/MW of Reserved Capacity per day

2024		
Point-to-Point Transmission Service		
Delivery Period	**Charge($)**	
Yearly: One twelfth of	$3,435.56	/MW of Reserved Capacity per year
Monthly	$286.29	/MW of Reserved Capacity per month
Weekly	$66.07	/MW of Reserved Capacity per week
Daily	$9.42	/MW of Reserved Capacity per day

Network Integration Transmission Service

For 2023, $286.29/MW of the Network Integration Transmission Service per month.
For 2024, $286.29/MW of the Network Integration Transmission Service per month.

Customer Obligations

The customer obligation for reserves is equal to 3.0 percent of Reserved Capacity for Point-to-Point Transmission Service and 3.0 percent of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within 30 minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for at least 60 minutes from the time of activation.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the

amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NS Power resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

	2023	**Charge ($)**	
1	Yearly delivery: One-twelfth of the demand charge of	$60,953.64	/MW of Reserved Capacity per year.
2	Monthly delivery:	$5,079.47	/MW of Reserved Capacity per month.
3	Weekly delivery:	$1,172.19	MW of Reserved Capacity per week
4	On-Peak Daily delivery:	$234.44	MW of Reserved Capacity per day.
5	Off-Peak Daily Delivery:	$167.00	MW of Reserved Capacity per day

	2024	**Charge ($)**	
1	Yearly delivery: One-twelfth of the demand charge of	$60,953.64	/MW of Reserved Capacity per year.
2	Monthly delivery:	$5,079.47	/MW of Reserved Capacity per month.
3	Weekly delivery:	$1,172.19	MW of Reserved Capacity per week
4	On-Peak Daily delivery:	$234.44	MW of Reserved Capacity per day.
5	Off-Peak Daily Delivery:	$167.00	MW of Reserved Capacity per day

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 3 above times the highest amount in megawatts of Reserved Capacity in any day during such week.

1. Discounts: Three principal requirements apply to discounts for transmission service as follows:

   (i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

   (ii) any customer-initiated requests for discounts (including requests for use by one's Wholesale Merchant or an affiliate's use) must occur solely by posting on the OASIS, and

   (iii) once a discount is negotiated, details must be immediately posted on the OASIS.

   For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission

service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

2. On-Peak days for this service are defined as Monday to Friday.

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

	2023	**Charge ($)**	
1	Monthly delivery:	$5,079.47	/MW of Reserved Capacity per month.
2	Weekly delivery:	$1,172.19	MW of Reserved Capacity per week
3	On-Peak Daily delivery:	$234.44	MW of Reserved Capacity per day.
4	Off-Peak Daily Delivery:	$167.00	MW of Reserved Capacity per day
5	On-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $14.65/MWh.		
6	Off-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $6.96/MWh.		

	2024	**Charge ($)**	
1	Monthly delivery:	$5,079.47	/MW of Reserved Capacity per month.
2	Weekly delivery:	$1,172.19	MW of Reserved Capacity per week
3	On-Peak Daily delivery:	$234.44	MW of Reserved Capacity per day.
4	Off-Peak Daily Delivery:	$167.00	MW of Reserved Capacity per day
5	On-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $14.65/MWh.		
6	Off-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $6.96/MWh.		

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any day during such week.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in Section 3 above times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any hour during such week.

1. Discounts: Three principal requirements apply to discounts for transmission service as follows:

   (i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

   (ii) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and

   (iii) once a discount is negotiated, details must be immediately posted on the OASIS.

   For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

2. On-Peak days for this service are defined as Monday to Friday.

3. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

For Point-to-Point service, the Transmission Provider will seasonally calculate loss factors to be used on a path-by-path basis. For each season, winter and summer, the power flow models used to calculate the losses will include peak and off-peak hours to derive an average loss factor for each path. For long-term Point-to-Point service, the annual loss factor to be used for a particular path is the average of the seasonal values. The loss factors will be posted on the Transmission Provider's OASIS site.

For Network Service, the Transmission Provider will apply the system average loss factor of 2.2 percent for 2023. This factor will be reviewed annually and is subject to change annually. It will be posted on the OASIS https://www.nspower.ca/oasis/system-reports-messages

Transmission Customers are required to provide the losses associated with their service. All Transmission Customers are required to include an amount of additional capacity in their service requests sufficient to carry the losses associated with their service.

Locational Loss Factors for new generation will be determined during the System Impact Study and be applied to generation dispatch merit order if such generation is to be economically dispatched by the Transmission Provider. If the generator is self-dispatched, loss factors will be applied to determine the unit net output.

Locational Loss Factors for each generator will be determined on an annual basis and will be posted on the OASIS.

1. The rate charged for Network Integration Transmission Service is

   For 2023: $4,317.55/MW-m
   For 2024: $4,317.55/MW-m

   based on the Transmission Customer's Net Non-coincident Monthly Peak Demand.

2. Net Non-coincident Monthly Peak Demand is the maximum hourly demand at each Point of Delivery designated as Network Load (including its designated Network Load not physically interconnected to the Transmission Provider's Transmission System).

3. Transmission congestion charges will be applied as follows:

   $A = B \times (C/D)$

   Where

A	=	the Network Customer's congestion charge for all hours of the month that congestion redispatch costs occurred.
B	=	Total redispatch costs during the month.
C	=	The Network Customer's load during the hours for which redispatch costs were incurred.
D	=	The sum of all Network Integration Transmission Service load (including load served by the Transmission Provider) and Point- to-Point Transmission Service scheduled serving load in the Operating area during the hours of the month for which redispatch costs were incurred.

SCHEDULE 4: ENERGY IMBALANCE SERVICE

This Schedule 4 is not applicable to Licenced Retail Suppliers.

The Generation Forecasting Service set out in Schedule 4A of the OATT will apply to Licenced Retail Suppliers only and is not applicable to any other Eligible Customer.

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within an Operating Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

For a bilateral schedule of a single load and its single generator, this ancillary service will be applied to the net of the generation and load imbalance. Otherwise, this Ancillary Service will be applied separately to deviations from load schedules and deviations from generation schedules. This ancillary service does not apply to power exported from the Operating Area, which is covered by the Generation Balancing Service of the Standard Generator Interconnection and Operation Agreement.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to

- Respond to transmission, generation or load contingencies.

For the purposes of Energy Imbalance Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Load Energy Imbalance Associated with Point-to-Point or Network Integration Transmission Service:

For each Transmission Customer taking service under Part II or Part III of this Tariff, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

A deviation band of +/- 1.5 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be applied hourly to any net load energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

Parties should attempt to eliminate energy imbalances within the limits of the deviation band within the billing month in accordance to the following:

- For hourly imbalances that arise during peak hours, such imbalances should be eliminated via deliveries or withdrawals during peak hours; and

- For hourly imbalances that arise during non-peak hours, such imbalances should be eliminated via deliveries or withdrawals during non-peak hours.

Net load energy imbalances within the deviation band that have not been eliminated at the end of the billing month will be subject to the charges set below:

- Energy supplied by the Transmission Provider during peak hours to compensate for a net shortfall in peak hours delivery over the billing month will be charged at the average on-peak system marginal cost for the billing month. Energy supplied by the Transmission

Provider during non-peak hours to compensate for a net shortfall in non-peak hours delivery over the billing month will be charged at the average non-peak system marginal cost for the billing month.

- Energy supplied to the Transmission Provider during peak hours as a net excess of the peak hours delivery over the billing month will be purchased by the Transmission Provider at the average on-peak system marginal cost for the billing month. Energy supplied to the Transmission Provider during non-peak hours as a net excess of the non-peak hours delivery over the billing month will be purchased by the Transmission Provider at the average non-peak system marginal cost for the billing month.

Energy imbalances outside of the deviation band are not eligible for elimination and are subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net hourly shortfall in delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Dispatchable Generators:

For Dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Non-Dispatchable Generators

For Non-dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

Energy Imbalances inside a deviation band of +/- 10 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at the hourly system marginal cost in the hour of the deviation.

All deviations from schedule outside of the +/- 10 percent deviation band will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

SCHEDULE 4A: GENERATION FORECASTING SERVICE

This Generation Forecasting Service set out in Schedule 4A of the OATT applies to Licenced Retail Suppliers only and is not applicable to any other Eligible Customer. Generation Forecasting Service addresses the accuracy of generation scheduling by Licenced Retail Suppliers.

This Schedule does not apply to forecasting discrepancies that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Forecast Deviation Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Each Licenced Retail Supplier shall use commercially reasonable efforts to provide accurate schedules and forecasts of production from renewable low-impact generators that are not dispatchable.

To the extent that such schedules or forecasts of hourly production of the aggregate of a Licenced Retail Supplier's RtR generation resources deviate from the actual production for reasons other than those that occur as a result of actions directed by the Operating Area operator the following charges shall apply:

An hourly deviation band of +/- 10 percent of the aggregate hourly scheduled or forecast quantity (with a minimum deviation band of +/- 2 MW) will be applied hourly to any forecast discrepancy that occurs as a result of the Transmission Customer's scheduled transaction(s).

- Hourly forecast discrepancies falling outside the hourly deviation band during peak hours will be charged at 10% of the average on-peak system marginal cost for the billing month.
- Hourly forecast discrepancies falling outside the hourly deviation band during non-peak hours will be charged at 10% of the average non-peak system marginal cost for the billing month.

This service is required to schedule the movement of power through, out of, within, or into an Operating Area. This service can be provided only by the operator of the Operating Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Operating Area operator. The charges, payable monthly, for Scheduling, System Control and Dispatch Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

1) Point-to-Point Transmission Service:

2023		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$4,852.88	/MW of Reserved Capacity per year
Monthly	$404.41	/MW of Reserved Capacity per month
Weekly	$93.32	/MW of Reserved Capacity per week
On-Peak Daily	$18.66	/MW of Reserved Capacity per day
Off-Peak Daily	$13.30	/MW of Reserved Capacity per day
On-Peak Hourly	$1.17	/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.55	/MW of Reserved Capacity per hour

2024		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$4,852.88	/MW of Reserved Capacity per year
Monthly	$404.41	/MW of Reserved Capacity per month
Weekly	$93.32	/MW of Reserved Capacity per week
On-Peak Daily	$18.66	/MW of Reserved Capacity per day
Off-Peak Daily	$13.30	/MW of Reserved Capacity per day
On-Peak Hourly	$1.17	/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.55	/MW of Reserved Capacity per hour

On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

2) Network Integration Transmission Service:

For 2023, $360.35/MW of Network Integration Transmission Service per month
For 2024, $360.35/MW of Network Integration Transmission Service per month

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Operating Area where the Transmission Provider's transmission facilities are located) under the control of the operating area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission system. The Transmission Customer must purchase this service from the Transmission Provider or the Operating Area operator. The charges, payable monthly, for such service are based on the rates set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Operating Area operator.

1) Point-to-Point Transmission Service

2023		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,249.91	/MW of Reserved Capacity per year
Monthly	$187.49	/MW of Reserved Capacity per month
Weekly	$43.27	/MW of Reserved Capacity per week
On-Peak Daily	$8.65	/MW of Reserved Capacity per day
Off-Peak Daily	$6.16	/MW of Reserved Capacity per day
On-Peak Hourly	$0.54	/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.26	/MW of Reserved Capacity per hour

2024		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,249.91	/MW of Reserved Capacity per year
Monthly	$187.49	/MW of Reserved Capacity per month
Weekly	$43.27	/MW of Reserved Capacity per week
On-Peak Daily	$8.65	/MW of Reserved Capacity per day
Off-Peak Daily	$6.16	/MW of Reserved Capacity per day
On-Peak Hourly	$0.54	/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.26	/MW of Reserved Capacity per hour

On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

2) Network Integration Transmission Service:

For 2023, $170.59 /MW of Network Integration Transmission Service per month.

For 2024, $170.59 /MW of Network Integration Transmission Service per month.

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Operating Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The charges, payable monthly, for Regulation and Frequency Response Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass- through of the costs charged to the Transmission Provider by that Operating Area operator.

1) Regulation (Point-to-Point Transmission Service)

The minimum period for which this service is available from the Transmission Provider is one day.

2023		
Regulation (Point-to-Point Transmission Service)		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,620.80	/MW of Reserved Capacity per year
Monthly	$218.40	/MW of Reserved Capacity per month
Weekly	$50.40	/MW of Reserved Capacity per week
Daily	$7.18	/MW of Reserved Capacity per day

2024		
Regulation (Point-to-Point Transmission Service)		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,620.80	/MW of Reserved Capacity per year
Monthly	$218.40	/MW of Reserved Capacity per month
Weekly	$50.40	/MW of Reserved Capacity per week
Daily	$7.18	/MW of Reserved Capacity per day

2) Regulation (Network Integration Transmission Service)

For 2023, $218.40/MW of Network Integration Transmission Service per month.
For 2024, $218.40/MW of Network Integration Transmission Service per month.

3) Load Following (Point-to-Point Transmission Service)

The minimum period for which this service is available from the Transmission Provider is one day.

2023		
Load Following (Point-to-Point Transmission Service)		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$9,489.96	/MW of Reserved Capacity per year
Monthly	$790.83	/MW of Reserved Capacity per month
Weekly	$182.50	/MW of Reserved Capacity per week
Daily	$26.00	/MW of Reserved Capacity per day

2024		
Load Following (Point-to-Point Transmission Service)		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$9,489.96	/MW of Reserved Capacity per year
Monthly	$790.83	/MW of Reserved Capacity per month
Weekly	$182.50	/MW of Reserved Capacity per week
Daily	$26.00	/MW of Reserved Capacity per day

4) Load Following (Network Integration Transmission Service)

For 2023, $790.83/MW of Network Integration Transmission Service per month.
For 2024, $790.83/MW of Network Integration Transmission Service per month.

5) Customer Obligations for Self-Supply and Third-Party Supply

The customer obligation for self-supply or third-party supply of Regulation is equal to 3.5 percent of Reserved Capacity for Point-to-Point Transmission Service and 3.5 percent of the Network Load for Network Integration Transmission Service.

The customer obligation for self-supply or third-party supply of Load Following is equal to 9.1 percent of Reserved Capacity for Point-to-Point Transmission Service and 9.1 percent of Network Load for Network Integration Transmission Service.

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The charges, payable monthly, for Spinning Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

1) Point-to-Point Transmission Service

2023		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,034.97	/MW of Reserved Capacity per year
Monthly	$169.58	/MW of Reserved Capacity per month
Weekly	$39.13	/MW of Reserved Capacity per week
Daily	$5.58	/MW of Reserved Capacity per day

2024		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$2,034.97	/MW of Reserved Capacity per year
Monthly	$169.58	/MW of Reserved Capacity per month
Weekly	$39.13	/MW of Reserved Capacity per week
Daily	$5.58	/MW of Reserved Capacity per day

The minimum period for which this service is available from the Transmission Provider is

one day.

2) Network Integration Transmission Service

For 2023, $169.58/MW of the Network Integration Transmission Service per month.
For 2024, $169.58/MW of the Network Integration Transmission Service per month.

3) Customer Obligations for Self-supply and Third-party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve - Spinning Reserve is equal to 2.0 percent of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service and 2.0 percent of the Network Load for Network Integration Transmission Service.

4) Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

5) Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission

Customers. This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Operating Reserve service will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

Supplemental Reserve Service (also referred to as Contingency Reserve - Supplemental) is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The charges, payable monthly, for Supplemental Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

1) Operating Reserve - Supplemental *(10* minute)

Point-to-Point Transmission Service

The minimum period for which this service is available from the Transmission Provider is one day.

2023		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$4,053.66	/MW of Reserved Capacity per year
Monthly	$337.80	/MW of Reserved Capacity per month
Weekly	$77.96	/MW of Reserved Capacity per week
Daily	$11.11	/MW of Reserved Capacity per day

2024		
Point-to-Point Transmission Service		
Delivery Period	**Charge ($)**	
Yearly: One twelfth of	$4,053.66	/MW of Reserved Capacity per year
Monthly	$337.80	/MW of Reserved Capacity per month
Weekly	$77.96	/MW of Reserved Capacity per week
Daily	$11.11	/MW of Reserved Capacity per day

Network Integration Transmission Service:

For 2023, $337.80/MW of the Network Integration Transmission Service per month.
For 2024, $337.80/MW of the Network Integration Transmission Service per month.

Customer Obligations for Self-supply and Third-Party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve - Supplemental Reserve will be equal to 8.3 percent of Reserved Capacity for Point-to-Point Transmission Service and 8.3 percent of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

2) Operating Reserve - Supplemental *(30* minute):

Point-to-Point Transmission Service

The minimum period for which this service is available from the Transmission Provider is one day.

2023		
Point-to-Point Transmission Service		
Delivery Period	**Charge($)**	
Yearly: One twelfth of	$3,435.56	/MW of Reserved Capacity per year
Monthly	$286.29	/MW of Reserved Capacity per month
Weekly	$66.07	/MW of Reserved Capacity per week
Daily	$9.42	/MW of Reserved Capacity per day

2024		
Point-to-Point Transmission Service		
Delivery Period	**Charge($)**	
Yearly: One twelfth of	$3,435.56	/MW of Reserved Capacity per year
Monthly	$286.29	/MW of Reserved Capacity per month
Weekly	$66.07	/MW of Reserved Capacity per week
Daily	$9.42	/MW of Reserved Capacity per day

Network Integration Transmission Service

For 2023, $286.29/MW of the Network Integration Transmission Service per month.
For 2024, $286.29/MW of the Network Integration Transmission Service per month.

Customer Obligations

The customer obligation for reserves is equal to 3.0 percent of Reserved Capacity for Point-to-Point Transmission Service and 3.0 percent of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within 30 minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for at least 60 minutes from the time of activation.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the

amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NS Power resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

	2023	**Charge ($)**	
1	Yearly delivery: One-twelfth of the demand charge of	$60,953.64	/MW of Reserved Capacity per year.
2	Monthly delivery:	$5,079.47	/MW of Reserved Capacity per month.
3	Weekly delivery:	$1,172.19	MW of Reserved Capacity per week
4	On-Peak Daily delivery:	$234.44	MW of Reserved Capacity per day.
5	Off-Peak Daily Delivery:	$167.00	MW of Reserved Capacity per day

	2024	**Charge ($)**	
1	Yearly delivery: One-twelfth of the demand charge of	$60,953.64	/MW of Reserved Capacity per year.
2	Monthly delivery:	$5,079.47	/MW of Reserved Capacity per month.
3	Weekly delivery:	$1,172.19	MW of Reserved Capacity per week
4	On-Peak Daily delivery:	$234.44	MW of Reserved Capacity per day.
5	Off-Peak Daily Delivery:	$167.00	MW of Reserved Capacity per day

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 3 above times the highest amount in megawatts of Reserved Capacity in any day during such week.

1. Discounts: Three principal requirements apply to discounts for transmission service as follows:

   (i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

   (ii) any customer-initiated requests for discounts (including requests for use by one's Wholesale Merchant or an affiliate's use) must occur solely by posting on the OASIS, and

   (iii) once a discount is negotiated, details must be immediately posted on the OASIS.

   For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission

service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

2. On-Peak days for this service are defined as Monday to Friday.

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

	2023	**Charge ($)**	
1	Monthly delivery:	$5,079.47	/MW of Reserved Capacity per month.
2	Weekly delivery:	$1,172.19	MW of Reserved Capacity per week
3	On-Peak Daily delivery:	$234.44	MW of Reserved Capacity per day.
4	Off-Peak Daily Delivery:	$167.00	MW of Reserved Capacity per day
5	On-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $14.65/MWh.		
6	Off-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $6.96/MWh.		

	2024	**Charge ($)**	
1	Monthly delivery:	$5,079.47	/MW of Reserved Capacity per month.
2	Weekly delivery:	$1,172.19	MW of Reserved Capacity per week
3	On-Peak Daily delivery:	$234.44	MW of Reserved Capacity per day.
4	Off-Peak Daily Delivery:	$167.00	MW of Reserved Capacity per day
5	On-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $14.65/MWh.		
6	Off-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $6.96/MWh.		

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any day during such week.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in Section 3 above times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any hour during such week.

1. Discounts: Three principal requirements apply to discounts for transmission service as follows:

   (i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

   (ii) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and

   (iii) once a discount is negotiated, details must be immediately posted on the OASIS.

   For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

2. On-Peak days for this service are defined as Monday to Friday.

3. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

For Point-to-Point service, the Transmission Provider will seasonally calculate loss factors to be used on a path-by-path basis. For each season, winter and summer, the power flow models used to calculate the losses will include peak and off-peak hours to derive an average loss factor for each path. For long-term Point-to-Point service, the annual loss factor to be used for a particular path is the average of the seasonal values. The loss factors will be posted on the Transmission Provider's OASIS site.

For Network Service, the Transmission Provider will apply the system average loss factor of 2.2 percent for 2023. This factor will be reviewed annually and is subject to change annually. It will be posted on the OASIS https://www.nspower.ca/oasis/system-reports-messages

Transmission Customers are required to provide the losses associated with their service. All Transmission Customers are required to include an amount of additional capacity in their service requests sufficient to carry the losses associated with their service.

Locational Loss Factors for new generation will be determined during the System Impact Study and be applied to generation dispatch merit order if such generation is to be economically dispatched by the Transmission Provider. If the generator is self-dispatched, loss factors will be applied to determine the unit net output.

Locational Loss Factors for each generator will be determined on an annual basis and will be posted on the OASIS.

1. The rate charged for Network Integration Transmission Service is

   For 2023: $4,317.55/MW-m
   For 2024: $4,317.55/MW-m

   based on the Transmission Customer's Net Non-coincident Monthly Peak Demand.

2. Net Non-coincident Monthly Peak Demand is the maximum hourly demand at each Point of Delivery designated as Network Load (including its designated Network Load not physically interconnected to the Transmission Provider's Transmission System).

3. Transmission congestion charges will be applied as follows:

   $A = B \times (C/D)$

   Where

A	=	the Network Customer's congestion charge for all hours of the month that congestion redispatch costs occurred.
B	=	Total redispatch costs during the month.
C	=	The Network Customer's load during the hours for which redispatch costs were incurred.
D	=	The sum of all Network Integration Transmission Service load (including load served by the Transmission Provider) and Point- to-Point Transmission Service scheduled serving load in the Operating area during the hours of the month for which redispatch costs were incurred.