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All the time.

MARITIME ELECTRIC
A FORTIS COMPANY

July 30, 2021

Island Regulatory and Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

2021 OATT Schedule Update

Please find enclosed five copies of Maritime Electric's Application to update the charges under the Company's Open Access Transmission Tariff ("OATT").

The proposed OATT charges were developed using the same methodology used in 2018 to develop the existing approved charges. The proposed charges are based on 2020 transmission system costs, determined through the 2020 Cost Allocation Study, while the existing charges are based on 2014 transmission system costs. During the six year period of 2015 to 2020, Maritime Electric invested over $35 million in the transmission system in response to load growth and system refurbishment, which results in the proposed charges.

If you have any questions or require additional information concerning any aspect of this Application, please do not hesitate to contact me at 902-629-3701.

Yours truly,

MARITIME ELECTRIC

Michelle Francis
Vice President, Finance & Chief Financial Office

MF40
Enclosures

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C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

**BEFORE THE ISLAND REGULATORY
AND APPEALS COMMISSION**

IN THE MATTER of Section 20 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order approving changes to the Open Access Transmission Tariff Schedules and for certain approvals incidental to such an order.

APPLICATION AND EVIDENCE OF MARITIME ELECTRIC COMPANY, LIMITED

Date: July 30, 2021

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1.0 APPLICATION

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

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INTRODUCTION

1. Maritime Electric Company, Limited ("Maritime Electric" or "the Company") is a Corporation incorporated under the laws of Canada with its head or registered office at Charlottetown and carries on a business as a public utility subject to the Electric Power Act ("EPA" or "the Act") engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

APPLICATION

2. Maritime Electric hereby applies for an Order of the Island Regulatory and Appeals Commission ("IRAC" or "the Commission") approving changes to the Open Access Transmission Tariff ("OATT") Schedules as outlined in the attached evidence.

3. The proposals contained in this Application represent a just and reasonable balance of the interests of Maritime Electric and those of its customers and will, if approved, allow the Company to operate an effective transmission system at a cost that is, in all circumstances, reasonable.

PROCEDURE

4. Filed hereto is the Affidavit of Jason Christopher Roberts and Angus Sumner Orford contains the evidence in which Maritime Electric relies in this Application.

Dated at Charlottetown, Province of Prince Edward Island, this 30th day of July, 2021.

D. Spencer Campbell, Q. C.

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Solicitors for Maritime Electric Company, Limited

2.0 AFFIDAVIT

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY
AND APPEALS COMMISSION

IN THE MATTER of Section 20 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order approving changes to the Open Access Transmission Tariff Schedules and for certain approvals incidental to such an order.

AFFIDAVIT

We, Jason Christopher Roberts of Suffolk and Angus Sumner Orford of Charlottetown, in Queens County, Province of Prince Edward Island, MAKE OATH AND SAY AS FOLLOWS:

1. We are the President and Chief Executive Officer and Vice-President, Corporate Planning and Energy Supply of Maritime Electric respectively and, as such, have personal knowledge of the matters deposed to herein, except where noted, in which case we rely upon the information of others and in which case we verily believe such information to be true.

2. Maritime Electric is a public utility subject to the Electric Power Act engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

3. We prepared or supervised the preparation of the evidence and to the best of our knowledge and belief the evidence is true in substance and in fact. A copy of the evidence is attached to this, our Affidavit, and is collectively known as Exhibit "A", contained in Sections 3 through 9 inclusive and Appendices A through I inclusive.

4. Section 11 contains a proposed Order of the Commission based on the Company's Application.

SWORN TO SEVERALLY at Charlottetown,
Province of Prince Edward Island,
the 30th day of July, 2021.
Before me:

Jason C. Roberts

Angus S. Orford

A Commissioner for taking Affidavits
in the Supreme Court of Prince Edward Island.

3.0 INTRODUCTION

3.1 Corporate Profile

Maritime Electric owns and operates a fully integrated system providing for the purchase, generation, transmission, distribution and sale of electricity throughout Prince Edward Island ("PEI"). The Company's head office is located in Charlottetown with generating facilities in Charlottetown and Borden-Carleton.

Maritime Electric is the primary provider of electricity on PEI delivering approximately 90 per cent of the energy on PEI. To meeting customers' energy demand and supply requirements, the Company has contractual entitlement to capacity and energy from NB Power's Point Lepreau Nuclear Generating Station ("Point Lepreau") and an agreement for the purchase of capacity and system energy from NB Power delivered via four submarine cables owned by the Province of PEI. The Company purchases 92.5 megawatts ("MW") of wind powered energy through various contracts with the PEI Energy Corporation.

3.2 Overview of Evidence

Under Section 20 of the Electric Power Act, Maritime Electric is permitted to submit to the IRAC, for its approval, amendments to the Open Access Transmission Tariff ("OATT"). This evidence herein is in support of the Company's proposed updates to the OATT to reflect changes in costs to supply the transmission services offered through the OATT.

These proposed updates are explained in Sections 7.0 to 9.0. Maritime Electric's currently approved OATT charges are based on 2014 cost data. The proposed updated charges are based on 2020 cost data.

4.0 BACKGROUND

An OATT defines the terms, conditions and price for access to an electric utility's transmission system for third-party users on the same basis as the utility uses the transmission system for serving its own load.

The evidence herein summarizes the approach used by Maritime Electric to develop the proposed OATT rates. Maritime Electric's approach closely follows NB Power's approach which, in turn, is based on the United States Federal Energy Regulatory Commission ("FERC") Pro Forma Tariff.

Maritime Electric currently supplies 90 per cent of the PEI load under a fully bundled, cost of service regulatory model. The remaining 10 per cent of the load is supplied by the City of Summerside Electric Department ("Summerside Electric"). Since 2002, Summerside has been purchasing its electricity supply from off-Island sources and Maritime Electric has been providing transmission wheeling service for Summerside Electric. In addition, Maritime Electric has been providing transmission wheeling service for the West Cape wind farm since 2007.

In November 2006, Maritime Electric filed for approval by the IRAC an OATT that provided for wholesale transmission access to meet the needs of Summerside Electric and merchant wind power developers on PEI. The proposed OATT also complied with the reciprocity requirements of the FERC Pro Forma Tariff, in that Maritime Electric's proposed OATT provided for wholesale transmission access on the Maritime Electric system in the same manner that wholesale transmission access is available to Maritime Electric on the New Brunswick system.

Following the November 2006 filing with IRAC, Maritime Electric conducted a stakeholder review process for the proposed OATT. The purpose of the stakeholder review was to receive input from interested parties, with a view to reaching consensus on as many issues as possible prior to appearing before IRAC. However, disagreement by Summerside Electric on certain issues led to legal proceedings, which were concluded early in 2015. In March 2008 (to take effect on June 30, 2008) and on July 30, 2009 (to take into account

Phase 2 at the West Cape Wind Farm), IRAC approved Maritime Electric's proposed OATT charges on an interim basis.

Maritime Electric filed for approval of an updated OATT in August 2016. This proposal included updated OATT charges (based on 2014 system costs) and addressed outstanding stakeholder issues that had been raised since the November 2006 initial filing. IRAC approved the OATT, effective August 1, 2018.

As indicated in this application, Maritime Electric is proposing updated OATT rates that reflect 2020 system costs, and is filing these updated OATT rates for IRAC approval.

5.0 PROVISIONS OF THE FERC PRO FORMA TARIFF

Under the FERC Pro Forma Tariff, the Transmission Provider (Maritime Electric in this case) is responsible for providing the transmission delivery services known as Network Integration Transmission Service ("Network Service") and Point-to-Point Transmission Service ("Point-to-Point Service") to all users on a non-discriminatory basis and at rates based on the cost of providing the service. The Transmission Provider is not required to supply either energy or generating capacity.

Network Service is firm transmission service for the delivery of both capacity and energy to the high side of the substation transformers of the Transmission Customer. It is usually used for supply of load within the system. On PEI, Maritime Electric uses Network Service for delivery to the 22 substations supplying its load across the Province.

Point-to-Point Service refers to the reservation of capacity for the transmission of energy from a Point of Receipt to a Point of Delivery. An example of this is a reservation from the New Brunswick interconnection at Murray Corner to the metering point for Summerside. This service is available on either a firm or a non-firm basis. Point-to-Point Service is usually used for wholesale transactions between systems rather than for the direct supply of load within a system.

The Pro Forma Tariff also requires that the Transmission Provider make certain **Ancillary Services** available at regulated rates. Ancillary Services are support services that range from the actions necessary to effect and balance a transfer of electricity between buyer and seller to services that are necessary to enable the transmission system to be operated reliably.

Services that must be available are as follows and the rates for such services are to be provided as per the Pro Forma Tariff under the following specific numbered schedules:

- Scheduling, System Control, and Dispatch Service [**Schedule 1**];
- Reactive Supply and Voltage Control from Generation Sources Service [**Schedule 2**];
- Regulation and Frequency Response Service [**Schedule 3**];

- Energy Imbalance Service [**Schedule 4**];
- Operating Reserves – Spinning Reserve Service [**Schedule 5**]; and
- Operating Reserves – Supplemental Reserve Service [**Schedule 6**].

Of these services, the Transmission Customer must take Scheduling, System Control and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service from the Transmission Provider. The Transmission Customer bears the responsibility of securing all other Ancillary Services when serving load within the Transmission Provider's control area. They can be self-supplied, purchased from third-party suppliers or purchased under regulated rates from the Transmission Provider.

A **Postage Stamp Rate**[1] for electricity transmission is one that does not vary according to the location of the buyer or the seller (Point of Delivery and Point of Receipt) just as postage stamps for letters are typically at a fixed price, regardless of their origin and destination. In the Pro Forma Tariff, both Network Service and Point-to-Point Service are provided through postage stamp rates.

[1] Platt's Glossary (www.platts.com).

6.0 SERVICES UNDER MARITIME ELECTRIC'S OATT

6.1 Transmission Service

Table 1 shows the rate for long-term firm Point-to-Point Transmission Service in Maritime Electric's proposed OATT and existing approved OATT as well as the corresponding rates in the New Brunswick and Nova Scotia.

Table 1 Rates for Long-Term Firm Point-to-Point Transmission Service	
Jurisdiction	**($/MW-year)**
Maritime Electric proposed OATT	49,858.76
Maritime Electric existing approved OATT	36,619.25
New Brunswick[2]	26,763.52
Nova Scotia[3]	59,875.87

The proposed Maritime Electric rate for long-term firm Point-to-Point Transmission Service has been calculated using the same approach as used by NB Power for its OATT. The calculation of the rate is described in Section 7.0.

Under Maritime Electric's proposed and existing OATT, the rates for Network Service are the same as those for long-term firm Point-to-Point Transmission Service.

6.2 Capacity-Based Ancillary Services

Ancillary Services can be grouped into two main categories. Capacity-based services are provided from generation capacity that must be committed to the provision of the service and is not able to be used at the same time for other purposes. Non capacity-based services do not require the commitment of generator capacity for provision of the service.

The Maritime Electric OATT provides for the same Capacity-Based Ancillary Services ("CBAS") as are in the NB Power OATT. These CBAS services are:

1. Regulation and Frequency Response from Generation Sources Service [**Schedule 3**] composed of:

[2] Effective January 1, 2019.
[3] 2017 rates, from NS Power Open Access Same Time Information System ("OASIS").

   i. Regulation (Automatic Generation Control or “AGC”),
   ii. Load Following, and
   iii. AGC and Load Following for Non-Dispatchable Wind Generation;

2. Operating Reserves – Spinning Reserve Service [**Schedule 5**]; and

3. Operating Reserves – Supplemental Reserve Service [**Schedule 6**] composed of:

   i. (a) Supplemental (10-minute), and
   ii. (b) Supplemental (30-minute).

Maritime Electric is unable to directly provide the Regulation and Load Following Services because for most of the year it does not run on-Island generation which could be used to regulate the energy flow on the NB/PEI interconnection. Instead, the New Brunswick system provides the Regulation and Load Following Services for the PEI load through the use of on-line generators in New Brunswick to regulate the energy flow on the New Brunswick interconnection with New England. The obligations for these services are allocated on a load ratio share basis to New Brunswick, northern Maine and PEI. Maritime Electric purchases the PEI obligation for Regulation and Load Following Services from NB Power and recovers this cost through Maritime Electric’s OATT Schedule 3 charges.

The requirements for Operating Reserves (Spinning, 10-minute Supplemental and 30-minute Supplemental) are determined for New Brunswick, northern Maine and PEI as a whole based on the Northeast Power Coordinating Council reliability requirements. These obligations are shared among the three entities on a load share basis. Spinning Reserve must be purchased from off-Island sources because for most of the year there are no on-Island generators running that could provide this service. However, 10-minute and 30-minute Supplemental Reserve can be provided by shut down generators that have quick start capability. Both Maritime Electric and Summerside Electric normally self-supply their 10-minute and 30-minute Supplemental Reserve requirements.

For the Maritime Electric OATT, the Company is proposing to use the same rates for Capacity-Based Ancillary Services as are in the NB Power OATT, consistent with existing OATT rates. To the extent that Maritime Electric provides these services by purchasing them from New Brunswick or elsewhere, the cost is a flow through with no mark up. To the extent that Maritime Electric provides Supplemental Reserve from one of its own generating units, the charge is as per the rates in the NB Power OATT (the rates for Capacity-Based Ancillary Services in the NB Power OATT are based on current day escalating proxy generating unit costs, not embedded costs for generating assets in New Brunswick).

6.3 Non Capacity-Based Ancillary Services

The Maritime Electric OATT provides for the same non capacity-based Ancillary Services as are in the NB Power OATT. These services are:

i. Scheduling, System Control and Dispatch Service [**Schedule 1**];
ii. Reactive Supply and Voltage Control from Generation or Other Sources Service [**Schedule 2**];
iii. Energy Imbalance Service [**Schedule 4**]; and
iv. Residual Uplift [**Schedule 10**].

Scheduling, System Control and Dispatch Service is required to schedule the movement of power through, out of, within, or into the Maritime Electric transmission system. This service is provided by Maritime Electric's Energy Control Centre. The rates for this service have been derived using the same approach as used by NB Power for its OATT. The calculations are shown in Appendix F.

Reactive Supply and Voltage Control from Generation or Other Sources Service is the operation of on-line generators or other sources to produce or absorb reactive power as needed in order to maintain transmission system voltages within acceptable limits. At the time of the 2019/2020 PEI winter peak, no reactive power was required from Maritime Electric's on-Island generators, but 25 MVAr would have been required in the event of an outage to one of the 138 kV transmission lines in New Brunswick between Memramcook and Murray Corner. The rates for this service have been derived as shown in Appendices G and H.

Energy Imbalance Service is a service whereby energy is provided or taken during an hour so as to make up for the difference between a transmission customer's scheduled use of the transmission system for the hour and their actual use of the transmission system for the hour.

Maritime Electric is unable to directly provide Energy Imbalance Service because for most of the year it does not run on-Island generators that could be used to regulate the energy flow on the NB/PEI interconnection. Instead, the Control Area Operator (“NB Power”) provides the Energy Imbalance Service associated with the NB/PEI interconnection through the use of on-line generators in New Brunswick to regulate the energy flow on the New Brunswick interconnection with New England. Maritime Electric purchases the service from NB Power and the costs are allocated among the users of the PEI transmission system in proportion to their imbalance along with FERC approved penalties to incent accurate scheduling.

When an unforeseen expense (or revenue) occurs that is not covered under one of the other schedules in the OATT, there must be a method that the Transmission Provider can recoup (or pay out) these costs. This is accomplished by using Schedule 10 – Residual Uplift. Residual Uplift includes revenues and expenses associated with such things as penalties for deficiencies, uncovered generation costs, and/or unrecovered costs associated with the purchase or sale of emergency energy.

6.4 Wholesale Transmission Access

Like the current NB Power OATT, Maritime Electric’s proposed OATT provides for only wholesale access. Retail access is not proposed to be made available because:

- Wholesale access is what is required under the FERC Pro Forma Tariff.
- Under the current legislation in PEI, Maritime Electric has the monopoly franchise for all of PEI except for the areas served by Summerside Electric.
- Apart from Summerside Electric, none of Maritime Electric’s other customers who take service at the transmission system level have expressed an interest in being able to purchase their electricity requirements from other suppliers.

7.0 CALCULATION OF TRANSMISSION SERVICE RATES

Maritime Electric's current approved OATT rates are based on historical 2014 data (taken from Maritime Electric's 2014 Cost Allocation Study), plus an estimate of the amount of non-firm service for the 99 MW merchant wind farm at West Cape and an assumption that Summerside Electric would be taking Network Service.

The OATT rates proposed in this Application are based on historical 2020 cost data[4] and the actual transmission system usage for 2020.

Table 2 shows how the transmission system revenue requirement for 2020 has been allocated by functional use (i.e., among the various users) for the proposed OATT rates compared to the allocation of the 2014 revenue requirement in the current OATT rates. The allocation of the 2020 revenue requirement is detailed in Appendix A. This revenue requirement includes all transmission asset related costs including amortization costs, operation, maintenance and administration costs, interest charges, income taxes and a regulated return on equity investment.

Table 2
Functional Allocation of Revenue Requirements ($ thousands)

Functional Use	2020 Revenue Requirement	2014 Revenue Requirement
Miscellaneous designated facilities	$ 45	$ 54
Maritime Electric - contracted wind related	1,783	1,121
Merchant wind related[5]	224	325
OATT related (shared by all users)	13,238	8,766
Energy Control Centre related	338	298
Total	**$ 15,628**	**$ 10,563**

The revenue requirement is a $/year quantity. To determine a $/MW-year rate for transmission service, the revenue requirement is divided by the transmission system usage, measured in MW. Table 3 shows the combined transmission system usages that

[4] 2020 cost data is based on Maritime Electric's 2020 Cost Allocation Study previously filed with the Commission on July 22, 2021.

[5] The merchant wind related revenue requirement includes only a small amount of financing costs because most of the capital cost for the associated designated transmission facilities was covered by a contribution in aid of construction.

were used for calculating the proposed rate compared to the existing approved rate. Details of the calculations supporting Table 3 are provided in Appendix B. Non-firm transmission service has been converted to equivalent firm quantities, such that multiplying an equivalent firm quantity by the rate for long-term firm service will give the same amount of revenue as was charged for the corresponding non-firm service.

Table 3
Network and Point-to-Point Transmission System Usage (MW)

Type of Service	2020 Firm Service or Equivalent	2014 Firm Service or Equivalent
Long term firm point-to-point	--	--
Maritime Electric network (average 12 CP)	213.8	189.0
Summerside Electric network (average 12 CP)	--	--
Summerside Electric short-term firm	11.6	10.0
Summerside Electric non-firm	4.7	6.7
Merchant Wind non-firm (based on non-Appalachian pricing)	35.4	33.7
Total	**265.5**	**239.4**

Normally the rates for non-firm service are higher for usage during on-peak hours than for off-peak hours. The methodology that is used throughout most of North America for calculating the higher on-peak rates is referred to as Appalachian pricing (the calculation methodology is shown in Appendices D, E and H). Maritime Electric is proposing that the transmission service rates (excluding rates for Ancillary Services) for exporting to off-Island should continue to be the same on-peak and off-peak (non-Appalachian pricing), provided there is no congestion. The reason for doing this is to align the OATT with Government policy of encouraging merchant wind development on PEI.

Given the revenue requirement and the equivalent transmission firm service usage, the rate for long-term firm service (either Point-to-Point or Network) is calculated in the Table 4.

Table 4 Calculation of Rate for Long-Term Firm Service (Point-to-Point or Network)			
		2020	**2014**
Revenue requirement[6] ($ thousands)	A	13,238	8,766
Firm transmission service or equivalent (MW)	B	265.5	239.4
Rate[7] ($/MW-year)	**C = A/B x 1,000**	**49,859**	**36,619**

Additional calculation detail, including the calculation of charges for time periods shorter than a year, is provided in Appendices C, D and E.

A summary of the proposed rates for services is shown in Table 5, along with the existing approved rates. Maritime Electric proposes that its OATT Schedules 3, 5 and 6 continue to refer to the NB Power web site for current rates.

Table 5 Rates for Services in Maritime Electric's Open Access Transmission Tariff				
Services	**Schedule in OATT**	**Reference**	**Proposed Rates ($/MW-month)**	**Existing Rates ($/MW-month)**
Scheduling, System Control and Dispatch	1	Appendix F	98.23	95.70
Reactive Supply and Voltage Control from Generation Sources	2	Appendix H	50.58	127.97
Regulation (Automatic Generation Control)[8]	3(a)	NB OATT	8,210.57	8,210.57
Load Following[8]	3(b)	NB OATT	8,175.68	8,175.68
AGC and Load Following for Non-Dispatchable Wind[8]	3(c)	NB OATT	$0.44/MWh	$0.44/MWh
Energy Imbalance	4	Section 6.3	n/a	n/a
Operating Reserve – Spinning[8]	5	NB OATT	8,164.06	8,164.06
Operating Reserve – Supplemental (10 minute)[8]	6(a)	NB OATT	3,908.48	3,908.48
Operating Reserve – Supplemental (30 minute)[8]	6(b)	NB OATT	3,908.48	3,908.48
Point-to-Point Transmission Service	7 and 8	Appendix D	4,154.90	3,051.60
Non-Capital Support Charge Rate	9	Section 8.0	1.88%	1.79%
Residual Uplift	10	Section 6.3	n/a	n/a
Network Transmission Service	Att. H	Appendix E	4,154.90	3,051.60

6 Rounded values, with the 2020 value presented in Appendix A.
7 Based on calculation using actual, not rounded figures.
8 These rates are taken directly from the NB Power OATT, effective January 1, 2019, and are shown for reference.

8.0 SCHEDULE 9 – NON-CAPITAL SUPPORT CHARGE

Schedule 9 is for operating, maintenance and administration ("OM&A") charges to designated transmission facilities for which a contribution in aid of construction was provided. Under Schedule 9, direct OM&A costs, such as repairs, are charged against the designated facility as incurred, while indirect (administrative or general) costs are recovered through an annual charge against the gross asset value of the designated facility. The calculation of this annual charge is shown in Table 6.

Table 6
Schedule 9 – Non-Capital Support Charge ($ thousands)

Transmission System Related	**2020 Data**	**2014 Data**
General Expenses (from Cost Allocation Study)	1,707	1,324
Insurance	464	185
Property Taxes	159	67
Total General Expenses	**2,340**	**1,576**
Maritime Electric Gross Transmission Assets (mid-year)	124,661	88,094
Plus Direct Assignment Facilities to Mid-2007	included above	included above
Total Gross Transmission Assets	**124,661**	**88,094**
General Expenses as Per Cent of Gross Transmission Assets	**1.88%**	**1.79%**

9.0 SYSTEM LOSSES

Maritime Electric applies system losses on a Postage Stamp basis for transmission system usage. The percentage losses for a month are set equal to the actual losses for the same month in the previous year. Average transmission system losses in 2020 were 1.7 per cent.

10.0 COMPARISON OF 2020 AND 2014 OATT RATES

10.1 Schedule 1 – Scheduling, System Control and Dispatch Service

The proposed rate for Schedule 1, per Table 5, has increased 2.6 per cent from the 2014 rates. As shown in Table 2 – Energy Control Centre-related costs have increased by 13 per cent, from $298,000 in 2014 to $338,000 in 2020, which was partially offset by the 11 per cent increase in total system usage from 259.0 MW in 2014 to 286.7 MW in 2020.

10.2 Schedule 2 – Reactive Supply and Voltage Control from Capacitive Sources Service

The proposed rate for Schedule 2, per Table 5, has decreased 60 per cent from $127.97 to $50.58 as a result of using a switched capacitive source to provide reactive power support instead of a synchronous condenser as the proxy unit. The derivation of the proposed Schedule 2 rate is shown in Appendix G and H.

The existing OATT rates for Schedule 2 were based on providing reactive power support through a synchronous condenser.

In 2016, the interconnection with New Brunswick had two submarine cables and two 138 kV transmission lines connecting the Memramcook, NB substation with the cable termination station at Richmond Cove, PEI. On-line generation operating on-Island was required under that system configuration to maintain voltage stability and provide sufficient capacitive support for the Island at peak under the worst-case single transmission contingency (i.e., the loss of one transmission line in New Brunswick).

The Interconnection Upgrade Project in 2016 and 2017 added two new submarine cables between PEI and New Brunswick, and a third 138 kV transmission line between Memramcook, NB and the New Brunswick cable termination stations. The submarine cables, by the nature of their construction, inherently produce reactive power, and by adding these cables, the Island has more reactive power at its disposal in the absence of on-Island generation. In addition, two 10 MVAr capacitors installed at the Charlottetown Substation in 2018 and two 5 MVAr capacitors installed in the Lorne Valley Substation in 2020 have added reactive power support in central and eastern PEI. This much-needed reactive power support results in less use of Combustion Turbine #3 for voltage support. The overall result of these projects is that switched capacitive sources were sufficient to meet the Island's reactive power voltage stability needs at peak in 2020 and online operation generation was not needed.

10.3 Schedules 3, 5 and 6

The proposed rates for Schedules 3, 5 and 6 are dependent on services provided by the New Brunswick Transmission System Operator. Any costs to Maritime Electric for these Schedules are flowed through to the Transmission Customer with no markup.

10.4 Schedules 7 and 8 – Point-to-Point Transmission Service

The proposed rates for Schedules 7 and 8, per Table 5, have increased 36 per cent due primarily to an increase in the Company's Total Gross Transmission Assets, per Table 6, which have increased 42 per cent over the same period.

From 2015 to 2020, the largest additions to the transmission system included transmission line Y-104[9], transmission-connected capacitors at Charlottetown and Lorne Valley, and the Y-109 extension to Borden. Capital improvements were made to the existing infrastructure, including transmission lines and substation breakers, as the original 138 kV facilities were approaching 40 years of age. In addition, transmission line protection and control equipment reached their end of life and significant investments have been made to modernize this equipment.

10.5 Schedule 9 – Non-Capital Support Charge Rate

The proposed Non-Capital Support Charge Rate has increased 5 per cent to 1.88 per cent in 2020 from 1.79 per cent in 2014.

The Company's indirect OM&A costs have increased 48 per cent from $1.576 million to $2.340 million as shown in Table 6, while the Total Gross Transmission Assets increased 42 per cent over the same period.

10.6 Schedule 10 – Residual Uplift

There are no proposed changes to the Schedule 10 terms and conditions.

[9] A portion of Y-104 is allocated to OATT transmission facilities, while the remainder is designated for Maritime Electric wind purchases and does not get reflected in the OATT charges.

11.0 PROPOSED ORDER

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 20 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order approving the changes to the Open Access Transmission Tariff Schedules and for certain approvals incidental to such an order.

UPON receiving an Application by Maritime Electric Company, Limited (the "Company") for approval of proposed amendments to its Open Access Transmission Tariff and certain approvals incidental to such an order;

AND UPON considering the Application and Evidence filed in support thereof;

NOW THEREFORE, for the reasons given in the annexed Reasons for Order and pursuant to the Electric Power Act;

IT IS ORDERED THAT

1. The Company's Open Access Transmission Tariff Schedules, as approved by the Commission in Order UE18-05, are amended effective ____________ 1, 2021 and shall continue to be in effect until otherwise ordered by the Commission.

DATED at Charlottetown, Prince Edward Island, this ___ day of ____, 2021.

BY THE COMMISSION:

Chair

Commissioner

Commissioner

APPENDIX A

Allocation of Year 2020 Transmission Costs by Function

Appendix A
ALLOCATION OF YEAR 2020 TRANSMISSION COSTS BY FUNCTION
($ thousands)

	Average gross plant in service	Average accum. amortztn	Average net plant in service	Amortztn expense	Amortztn including Allocated Indirects	OM&A initial assignmnt	Allocations of OM&A: Unassignd OM&A	Allocations of OM&A: General by gross plant	Allocations of OM&A: Allocated OM&A expense	Interest, return & taxes	Total from Cost Allocation Study	Accrued revenue adjustment	Total cost
					A	B	C	D	E = B + C + D	F	G = A + E + F	H	I = G + H
Transmission costs from 2020 Cost Allocation Study				3,014		9,147				6,812	18,974	(56)	18,918
Less adjustments				(79)		(3,211)					(3,290)		
Total Transmission Costs from 2020 Cost Allocation Study after Adjustments				2,935	-	5,937	-	-	-	6,812	15,684	(56)	15,628
Miscellaneous designated amounts													
- substations (for MECL generation)	380	380	-	-	-		4	7	11	-	11		11
- substations (other)	133	34	100				2	2	4		4		4
- lines (other)	369	132	238				3	7	10		10		10
- telecommunications (other)	357	259	98	6	7		7	7	13		20		20
	1,240	804	436	6	7	-	16	23	38	-	45		45
Designated for MECL wind purchases													
- substations	3,302	531	2,771	54	63		38	60	99	279	441	(2)	439
- lines	9,070	1,810	7,260	267	313		75	166	241	732	1,286	(6)	1,280
- telecommunications	400	128	272	19	22		7	7	15	27	64	(0)	64
	12,772	2,468	10,304	340	398	-	121	233	354	1,039	1,792	(9)	1,783
Designated for IPP merchant wind													
- substations	1,441	374	1,067	(22)	(26)			26	26		1		1
- lines	16,497	4,329	12,168	(72)	(84)	-	-	301	301	2	219		219
- telecommunications	129	94	35	2	2			2	2		5		5
	18,068	4,798	13,270	(92)	(108)	-	-	330	330	2	224		224
OATT transmission facilities													
- interconnection (incl. NB Sched 9 charges)	-	-	-	-	-	1,930	-	-	1,930	-	1,930		1,930
- submarine cables contingency fund						375			375		375		375
- substations	29,116	9,181	19,935	473	555		338	532	870	2,010	3,435	(17)	3,419
- lines	55,437	19,147	36,290	1,646	1,932		459	1,013	1,472	3,660	7,064	(30)	7,034
- telecommunications	2,061	1,346	716	98	114		39	38	76	72	263	(1)	262
- OATT administration	-	-	-	-	-	218	-	-	218	-	218	-	218
	86,614	29,673	56,940	2,217	2,602	2,523	836	1,582	4,941	5,742	13,285	(47)	13,238
Energy Control Centre	715	430	284	31	36	260		13	274	29	338		338
Unassigned OM&A													
- substation OM&A						382	allocate by substation gross plant						
- lines OM&A						537	allocate by lines gross plant						
- telecommunications OM&A						53	allocate by tele. gross plant						
Indirect													
- Insurance						464	allocate by gross plant with General						
- Vehicles	2,888	1,232	1,656	205		-							
- General	2,366	867	1,499	229		1,717	allocate by gross plant						
Totals	124,661	40,272	84,389	2,935	2,935	5,937	972	2,181	5,937	6,812	15,684	(56)	15,628

Note: Values shown are rounded for ease of presentation, and sums may not match exactly. OATT rates in Appendices A-I, and included in Schedules 1-10 and Attachment H, are based on actuals.

APPENDIX B

Demand Determinants for 2020

Appendix B
DEMAND DETERMINANTS FOR 2020

Services		2020 usage (MW)	2020 usage (MWh)	Transmission Service equivalent firm (MW)		Schedules 1 and 2 equivalent firm (MW)	
Long-term firm Point-to-Point reservations		-		-		-	
Average of 12 CP for MECL load (Network)		213.8		213.8		213.8	
Average of 12 CP for Sside load (Network)		-		-		-	
Short-term firm Point-to-Point service:							
- Summerside	(average for 12 months)	11.6		11.6		11.6	
Non-firm Point-to-Point service:							
- Summerside	on-peak		16,054	3.8	(Appalachian)	3.8	(Appalachian)
	off-peak		7,756	0.9		0.9	
- West Cape wind	on-peak		168,261	19.2	(non-Appalachian)	40.4	(Appalachian)
	off-peak		141,464	16.2		16.2	
				265.5		286.7	

APPENDIX C

Calculation of Unit Costs for Transmission and Scheduling, System Control and Dispatch

APPENDIX C

CALCULATION OF UNIT COSTS FOR TRANSMISSION AND SCHEDULING, SYSTEM CONTROL AND DISPATCH*

Services	Total usage by service (MW)	Total usage by service %	Total Cost Allocated to OATT Transmission Facilities ($ thousands)	Total Allocated cost by service ($ thousands)	Annual unit cost ($ / MW - yr)	Monthly unit cost ($ / MW - mo)
	A	**B**	**C**	**D**	**E**	**F**
	Appendix B		**Appendix A**	**= B X C**	**= D X 1,000 / A**	**= E / 12**
OATT Point to Point	51.7	19.5%	$ 13,238	$ 2,577	$ 49,859	$ 4,154.90
OATT Network	213.8	80.5%	$ 13,238	10,661	$ 49,859	$ 4,154.90
Subtotal Transmission Services	265.5	100%		13,238	$ 49,859	$ 4,154.90
Misc. designated amounts				45		
MECL wind purchases				1,783		
IPP merchant wind				224		
Schedule 1 Sched, Sys Control & Dispatch	286.7	100%	$ 338	338	$ 1,179	$ 98.23
Total				$ 15,628		

Note: Charges for firm Point-to-Point are the same as for Network service

* Calculations based on underlying whole number which has been rounded for presentation purposes

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APPENDIX D

Rates for Point-To-Point Transmission Service

Appendix D
RATES FOR POINT-TO-POINT TRANSMISSION SERVICE

Total annual cost by class, per Appendix C		2,577	$ thousands
Total usage by class [1], per Appendix C		51.7	MW
Yearly[2] (same as for Network Service)		49,858.76	$ / MW - yr
Monthly[3]	= Yearly / 12	4,154.90	$ / MW - mo
Weekly[3]	= Yearly / 52	958.82	$ / MW - wk
On-peak daily[3, 5]	= Weekly / 5	191.76	$ / MW - day
Off-peak daily[3]	= Yearly / 365	136.60	$ / MW - day
On-peak hourly[4, 5]	= On-peak daily / 16	11.99	$ / MWh
Off-peak hourly[4]	= Yearly / 8,760	5.69	$ / MWh

Notes: 1 Usage based on long term firm reservations or equivalent

2 Firm service only

3 Firm or Non firm service

4 Non firm service only

5 Exporters use the corresponding off-peak rate (non-Appalachian pricing)

APPENDIX E

Rates for Network Transmission Service

Appendix E

RATES FOR NETWORK TRANSMISSION SERVICE

Attachment H

Total annual cost by class, per Appendix C		10,661	$ thousands
Total usage by class (average of 12 CP), per Appendix C		213.8	MW
Yearly		49,858.76	$ / MW - yr
Monthly	= Yearly / 12	4,154.90	$ / MW - mo

APPENDIX F

Rates for Scheduling, System Control and Dispatch Service

Appendix F

RATES FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

SCHEDULE 1

Total annual cost (for Energy Control Centre), per Appendix C		338	$ thousands
Total usage, per Appendix C		286.7	MW

For Point to Point Service[1]

Yearly[2]		1,178.77	$ / MW - yr
Monthly[3]	= Yearly / 12	98.23	$ / MW - mo
Weekly[3]	= Yearly / 52	22.67	$ / MW - wk
On-peak daily[3]	= Weekly / 5	4.53	$ / MW - day
Off-peak daily[3]	= Yearly / 365	3.23	$ / MW - day
On-peak hourly[4]	= On-peak daily / 16	0.28	$ / MWh
Off-peak hourly[4]	= Yearly / 8,760	0.13	$ / MWh

For Network Service

Yearly		1,178.77	$ / MW - yr
Monthly	= Yearly / 12	98.23	$ / MW - mo

Notes: 1 Usage based on long-term firm reservations

2 Firm service only

3 Firm or Non firm service

4 Non firm service only

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APPENDIX G

Revenue Requirement for Reactive Supply
and
Voltage Control Service from Capacitive Sources

Appendix G

REVENUE REQUIREMENT FOR REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE

FROM CAPACITIVE SOURCES

	Capacity (MVAr)	Capital cost ($ millions)	Capital cost ($ / MVAr)	Annual OM&A ($)
	A	B	C= B X 1,000,000 / A	D
Proxy unit for MECL Tariff calculation	30	2.6	86,667	5,000

Expected service life	45	years
MECL annual fixed charges rate	7.84	%

Estimated annual cost for a 30 MVAr transmission connected capacitors:

Capital related	203,840	$ / yr	(7.84% of $2.6M)
Annual OM&A	5,000	$ / yr	
Total	208,840	$ / yr	
Per unit cost	6,961	$ / MVAr - yr	($208,840 / 30 MVAr)

Estimated MVAr required from on-Island generators at 2020 winter peak	-	MVAr
Additional requirement for loss of a 138 kV line in New Brunswick	25	MVAr
Total MVAr requirement from on-Island capacitors	**25**	**MVAr**

Annual revenue requirement pf Reactive Supply and Voltage Control = 25 MVAr x 6,961 $ / MVAr - yr

= 174,033 $ / yr

APPENDIX H

Rates for Reactive Supply and Voltage Control Service from Capacitive Sources

Appendix H
RATES FOR REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE
FROM CAPACITIVE SOURCES

Total annual cost	(Appendix G)	174	$ thousands
Total usage	(Appendix B)	286.7	MW

For Point to Point Service

Yearly		606.94	$ / MW - yr
Monthly	= Yearly / 12	50.58	$ / MW - mo
Weekly	= Yearly / 52	11.67	$ / MW - wk
On-peak daily	= Weekly / 5	2.33	$ / MW - day
Off-peak daily	= Yearly / 365	1.66	$ / MW - day
On-peak hourly	= On-peak daily / 16	0.15	$ / MWh
Off-peak hourly	= Yearly / 8,760	0.07	$ / MWh

For Network Service

Yearly		606.94	$ / MW - yr
Monthly	= Yearly / 12	50.58	$ / MW - mo

Notes: 1 The transmission customer (Point to Point or Network) must purchase this service from the transmission provider.

APPENDIX I

Maritime Electric Annual Fixed Charge Rate for Capacitive Sources

APPENDIX I

FIXED CHARGES RATE FOR CAPACITIVE SOURCES

1. Capitalization:

- Debt	60.00	%	@	5.27	%	=	3.16
- Common equity	40.00	%	@	9.35	%	=	3.74
- Weighted average cost of capital (r)							6.90

2. Capital recovery factor (f): 45 years @ 6.90 %

$$\frac{r(1 + r)^n}{(1 + r)^n - 1} = 7.26$$

3. Levelized capital cost allowance: @ i = 8.00 %

$$\frac{f \times 100 \times i}{r + i} = 3.90$$

4. Future income tax: @ 31.00 % tax rate

- Levelized capital cost allowance		3.90	
- Less str line amortization @	45 years	2.22	
	0.31 x	1.68 =	0.52

5. Levelized cost of debt:

- Capital recovery factor	7.26
- Less straight line amortization	2.22
- Less future income tax	0.52
	4.52

- Levelized cost of debt = $\frac{3.16}{6.90} \times 4.52 = 2.07$

6. Levelized current income tax:

- Capital recovery factor	7.26
- Less levelized capital cost allowance	3.90
- Less levelized cost of debt	2.07
	1.29

- Income tax payable $\frac{1.29}{1 - 0.31} \times 0.31 = 0.58$

7. Annual fixed charges rate:

- Capital recovery factor	7.26
- Plus current income taxes payable	0.58
- Total	7.84

APPENDIX J

Maritime Electric Proposed Schedules 1-10 and Attachment H

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the Transmission Provider in which the transmission facilities used for transmission service are located. The Transmission Customer must purchase this service from the Transmission Provider. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below.

The charges for this ancillary service, payable monthly, are set forth below:

Point-to-Point:

1. Yearly Delivery:	One twelfth of C$1,178.77/MW of Reserved Capacity per year.
2. Monthly Delivery:	C$98.23/MW of Reserved Capacity per month.
3. Weekly Delivery:	C$22.67/MW of Reserved Capacity per week.
4. On-Peak Daily Delivery:	C$4.53/MW of Reserved Capacity per day.
5. Off-Peak Daily Delivery:	C$3.23/MW of Reserved Capacity per day.
6. On-Peak Hourly Delivery:	C$0.28/MW of Reserved Capacity per hour.
7. Off-Peak Hourly Delivery:	C$0.13/MW of Reserved Capacity per hour.

Network Integration C$98.23/MW of Network Integration Service per month.

On-Peak days for the 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.

SCHEDULE 2

Reactive Supply and Voltage Control from Capacitive Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the Control Area Operator (in the Control Area where the Transmission Provider's transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Capacitive Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Capacitive 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 Capacitive Sources Service is to be provided directly by the Transmission Provider (Maritime Electric). The Transmission Customer must purchase this service from the Transmission Provider. The charges for such service will be based on the rates set forth below.

The charges for this ancillary service, payable monthly, are set forth below:

Point-To-Point:

1.	Yearly Delivery:	One twelfth of C$606.94/MW of Reserved Capacity per year.
2.	Monthly Delivery:	C$50.58/MW of Reserved Capacity per month.
3.	Weekly Delivery:	C$11.67/MW of Reserved Capacity per week.
4.	On-Peak Daily Delivery:	C$2.33/MW of Reserved Capacity per day.
5.	Off-Peak Daily Delivery:	C$1.66/MW of Reserved Capacity per day.
6.	On-Peak Hourly Delivery:	C$0.15/MW of Reserved Capacity per hour.
7.	Off-Peak Hourly Delivery:	C$0.07/MW of Reserved Capacity per hour.

Network Integration C$50.58/MW of Network Integration Service per month.

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.

SCHEDULE 3

Regulation and Frequency Response Service

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 Maritime Electric, the Transmission Provider (or the Control 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 Control Area. The aforementioned Transmission Provider obligation to offer this service is conditional upon the Transmission Provider having sufficient visibility and control of the resources in the area in which the load is located to allow the Transmission Provider to perform its balancing function in a non-discriminatory fashion.

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 Transmission Provider, in collaboration with the Control Area Operator, will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control 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 Control Area Operator.

The Regulation and Frequency Response Service is comprised of three components. These components are called Automatic Generation Control (AGC), Load Following and AGC and Load Following for Non-Dispatchable Wind Power Generators and are priced separately below.

Intra-hour performance will be monitored for specific market participant behaviour that introduces a disproportionate burden on the Control Area Operator with respect to AGC and load following. Sanctions may be invoked. The determination of whether or not such activity is disproportionate will take into account the extent to which the offending party is already paying the Control Area Operator for, or self-supplying to the Control Area Operator, the AGC and/or load following services. This determination will give consideration to the net effect of aggregated intra-hour behaviours of Non-Dispatchable Generators before any such sanction is invoked.

3(a) **AGC**: This ancillary service is the provision of generation and load response capability, including capacity, energy and maneuverability, that responds often and rapidly to automatic control signals issued by the Control Area Operator.

The charges for this ancillary service are a pass through from the Control Area Operator and are available at the web site http://tso.nbpower.com under the Tariff tab. If the purchase rate from the Control Area Operator changes the rate under this schedule 3(a) will immediately change as well.

There will be an adder applied to these prices when the Control Area Operator incurs extra costs. These extra costs will be limited to out-of-order dispatch costs associated with revised generation or load dispatch for the purpose of providing this ancillary service.

3(b) **Load Following**: This ancillary service is the provision of generation and load response capability, including capacity, energy and maneuverability, that is dispatched within the scheduling period by the Control Area operator at frequencies and rates that are lower and slower than AGC.

The charges for this ancillary service are a pass through from the Control Area Operator and are available at the web site http://tso.nbpower.com under the Tariff tab. If the purchase rate from the

Control Area Operator changes the rate under this schedule 3(b) will immediately change as well.

There will be an adder applied to these prices when the Control Area Operator incurs extra costs. These extra costs will be limited to out-of-order dispatch costs associated with revised generation or load dispatch for the purpose of providing this ancillary service.

3(c) AGC and Load Following for Non-Dispatchable Wind Power Generators: This ancillary service is the combination of AGC and Load Following service required to address the aggregate impact of non-dispatchable wind generation in the balancing area. The rate is inclusive of capacity and out-of-order dispatch costs. The Transmission Provider shall seek to minimize these costs. The Transmission Provider shall discount the rates to the extent that revenues from this service are expected to exceed expenses for the purchase of these services.

The charges for this ancillary service are a pass through from the Control Area Operator and are available at the web site http://tso.nbpower.com under the Tariff tab. If the purchase rate from the Control Area Operator changes the rate under this schedule 3(c) will immediately change as well.

This service does not apply to generators that are exporting from the balancing area and for which dynamic scheduling occurs whereby the delivery to an adjacent balancing area is equivalent to the generator's production.

SCHEDULE 4

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the expected and the actual hourly injection or withdrawal from the Transmission System.

In the case of loads, including exports, Energy Imbalance is the difference between the scheduled withdrawal and the actual withdrawal of energy from the Transmission System. In the case of supply sources, including imports, Energy Imbalance is the difference between the scheduled injection and the actual injection to the Transmission System.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Transmission Provider (MECL) or the Control Area Operator to:

- Balance total load and generation for the Control Area, or a portion thereof, 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 this Schedule, Energy Imbalance Service will be settled between the Transmission Provider and the party responsible for the relevant transaction using the Transmission Provider's actual average hourly cost of the last megawatt dispatched for any purpose. For greater clarity, it is the hourly marginal cost of the Control Area Operator when the transmission interface between the MECL system and the NB Power system is not constrained and it is the marginal cost of the MECL system when the interface is constrained.

Energy Imbalances will be monitored by the Control Area Operator for both specific occurrences of inappropriate behaviour and patterns of inappropriate behaviour. Any such behaviour will be addressed by the Control Area Operator in its market monitoring role.

An optional service will be available for Non-Dispatchable Generators, from the Control Area Operator, whereby the hourly variances in deliveries to the Transmission System of all generators that are registered to receive this service will be aggregated and the resulting net imbalance will be allocated to those contributing to the imbalance in proportion to their respective contributions. This service is available for a minimum term of one calendar month at the prior request of the generator registrant and subject to the approval of the Transmission Provider.

SCHEDULE 5

Operating Reserve – Spinning Reserve Service

Spinning Reserve Service (also referred to as Contingency Reserve – Spinning) 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 and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make arrangements to satisfy its Spinning Reserve Service obligation. The aforementioned Transmission Provider obligation to offer this service is conditional upon the Transmission Provider having sufficient visibility and control of the resourced in the area in which the load is located to allow the Transmission Provider to perform its balancing function in a non-discriminatory fashion. To the extent the Control Area Operator (NB Power TSO) performs this service for the Transmission Provider (MECL), charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator.

Customer Obligations

The customer obligation for reserves will be determined as a percentage of the customer load coincident with the Maritimes annual peak load as determined for the Control Area.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within seven minutes[1] of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for 60 minutes from activation.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified

[1] NPCC criterion for both spinning and 10 minute supplemental reserve is 10 minutes and 30 minutes for 30 Minute Reserve. Note, however, that this time span includes the decision-making time taken by the Transmission Provider. This is assumed to be 3 minutes for spinning and supplemental and 6 minutes for 30 Minute Reserve. Thus the timeframes under consideration are 7 minutes and 24 minutes respectively.

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 (1) those under contract with the Transmission Provider, (2) those provided by Transmission Customers, (3) those contracted from third parties by Transmission Customers. 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 Criteria/Directories and Control Area Operator reliability standards.

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 current applicable rates from the Control Area Operator through the NB OATT are available at the NB TSO web site http://tso.nbpower.com. If the purchase rate from the Control Area Operator changes, the rate under this Schedule 5 will immediately change as well.

There will be an adder applied to these prices when the Transmission Provider incurs extra costs. The extra costs will be limited out-of-order dispatch costs associated with revised generation or load dispatch for the purchase of providing this ancillary service. Out-of-order dispatch costs will be calculated as the difference between the cost of serving load and the cost of service load plus auxiliaries. These costs will be charged to the Transmission Customers that take this service on a pro rata share basis as a function of the quantity of the service purchased from the Transmission Provider at the time that the out-of-dispatch occurs.

SCHEDULE 6

Operating Reserve -– Supplemental Reserve Service

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 load fully removeable from the system within ten minutes of the contingency event. The Transmission Provider, or the Control Area Operator on its behalf, must offer this service when the transmission service is used to serve load within its Control 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 aforementioned Transmission Provider obligation to offer this service is conditional upon the Transmission Provider having sufficient visibility and control of the resources in the area in which the load is located to allow the Transmission Provider or the Control Area Operator to perform its balancing function in a non-discriminatory fashion. 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 amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control 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 Control Area operator.

6(a) Operating Reserve – Supplemental (10 minute)

This ancillary service is the portion of Operating Reserve – Supplemental that is available within 7 minutes.

The current applicable rates from the Control Area Operator through the NB OATT or directly from the Transmission Provider (MECL) are those provided at the NB TSO web site http://tso.nbpower.com under the Tariff tab. If the purchase rate from that web site changes the rate under this schedule 6(a) will immediately change as well.

There will be an adder applied to these prices when the Transmission Provider incurs extra costs.

These extra costs will be limited to out-of-order dispatch costs associated with revised generation or load dispatch for the purpose of providing this ancillary service. Out-of-order dispatch costs will be calculated as the difference between the cost of serving load and the cost of serving load plus ancillaries. These costs will be charged to Transmission Customers that take this service on a pro rata share basis as a function of the quantity of the service purchased from the Transmission Provider at the time that the out-of-order dispatch occurs.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within seven minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for sixty minutes from activation.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (1) those under contract with the Transmission Provider, (2) those provided by Transmission Customers, (3) those contracted from third parties by Transmission Customers. 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 Criteria/Directories and Control Area Operator reliability standards.

6(b) Operating Reserve – Supplemental (30 minute)

This ancillary service is the portion of the Operating Reserve – Supplemental that is available within 24 minutes.

The current applicable rates from the Control Area Operator through the NB OATT or directly from the Transmission Provider (MECL) are those provided at the NB TSO web site http://tso.nbpower.com under the Tariff tab. If the purchase rate from that web site changes the rate under this schedule 6(b) will immediately change as well.

There will be an adder applied to these prices when the Transmission Provider incurs extra costs.

These extra costs will be limited to out-of-order dispatch costs associated with revised generation or load dispatch for the purpose of providing this ancillary service.

Out-of-order dispatch costs will be calculated as the difference between the cost of serving load and the cost of serving load plus ancillaries. These costs will be charged to Transmission Customers that take this service on a pro rata share basis as a function of the quantity of the service purchased from the Transmission Provider at the time that the out-of-order dispatch occurs.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within seven minutes[2] of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for 60 minutes from activation.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (1) those under contract with the Transmission Provider, (2) those provided by Transmission Customers, (3) those contracted from third parties by Transmission Customers. 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 Criteria/Directories and Control Area Operator reliability standards.

[2] NPCC criterion for both spinning and 10 Minute supplemental reserve is 10 minutes and 30 minutes for 30 Minute Reserve. Note, however, that this time span includes the decision-making time taken by the Transmission Provider. This is assumed to be 3 minutes for spinning and 10 Minute Supplemental and 6 minutes for 30 Minute Reserve. Thus the timeframes under consideration are 7 minutes and 24 minutes respectively for reserves that are self supplied.

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1.	Yearly Delivery:	One twelfth of the demand charge of C$49,858.76/MW of Reserved Capacity per year.
2.	Monthly Delivery:	C$4,154.90/MW of Reserved Capacity per month.
3.	Weekly Delivery	C$958.82/MW of Reserved Capacity per week.
4.	On-Peak Daily Delivery:	C$191.76/MW of Reserved Capacity per day.
5.	Off-Peak Daily Delivery:	C$136.60/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 kilowatts of Reserved Capacity in any day during such week.

6. Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS**,** (2) 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 (3) 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(s) 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.

7. On-Peak days for this service are defined as Monday to Friday.

8. Reservations for off-Island electricity exports will be discounted to off-Peak rates during periods when transmission path(s) for export are unconstrained.

9. Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section 23.1 of the Tariff.

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Non-Firm Point-To-Point Transmission Service at the sum of the applicable charges set forth below:

1. Monthly delivery: C$4,154.90/MW of Reserved Capacity per month.

2. Weekly delivery: C$958.82/MW of Reserved Capacity per week.

3. On-Peak Daily delivery: C$191.76/MW of Reserved Capacity per week.

4. Off-Peak Daily delivery: C$136.60/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 (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5. On-Peak Hourly delivery: C$11.99/MW of Reserved Capacity per hour.

6. Off-Peak Hourly delivery: C$5.69/MWh of Reserved Capacity per hour.

   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 kilowatts 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 kilowatts of Reserved Capacity in any hour during such week.

7. Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) 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 (3) 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(s) 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.

8. 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.

9. Reserved Capacity charges for off-Island electricity exports will be discounted to off-Peak rates during periods when transmission path(s) for export are unconstrained.

10. Reserved Capacity charges for transmission access for off-Island electricity exports, in excess of actual electricity exports for the hour, will be discounted to 10% of the applicable Reserved Capacity charge rate for the hour during periods when the transmission path(s) for export is not constrained.

11. Resales: The rates ~~and~~ rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section 23.1 of the Tariff.

SCHEDULE 9

Non-Capital Support Charge Rate

The Non-Capital Support Charge Rate is an OM&A related carrying charge and shall include, without limitation, all indirect OM&A expenses. This rate is calculated as the indirect OM&A component of the Transmission Provider's revenue requirement divided by the total plant (fixed assets) upon which the revenue requirement is based. This rate is applied to assets for which the Transmission Customer has been assigned an obligation to make support payments to the Transmission Provider. A Direct Assignment Facility for the interconnection of a generator that is paid for by the Transmission Customer but maintained by the Transmission Provider is one such example. The rate is as follows:

Non-Capital Support Charge Rate = 1.88%

The capital charges that are subject to support for a particular Transmission Customer are to be identified in the respective interconnection agreement.

Calculation of the support rate:

OM&A (Indirect)	C$2.340	million/year
Fixed Assets (Gross Book Value)	C$124.661	million
OM&A ÷ Fixed Assets	1.88	%

This rate will be updated by Maritime Electric subject to the approval of IRAC and will be used to calculate the support payments for capital charges that are subject to support payments. One-twelfth of the Capital Support Rate Charges will be paid monthly by the Transmission Customer.

In addition to the Non-Capital Support Rate Charge the Transmission Customer will be billed monthly on a time and materials basis for all OM&A direct costs (labour, materials and transportation) associated with the Direct Assignment Facilities.

SCHEDULE 10

Residual Uplift

The Residual Uplift provides a periodic settlement of various Transmission Provider expenses and revenues that are not reflected in other schedules in this OATT. The net value of these expenses and revenues can be either positive or negative in any given settlement period.

Residual Uplift shall be calculated for each settlement period in accordance with the Transmission Provider's rules and procedures as provided on the Maritime Electric website. Residual Uplift includes revenues and expenses associated with such things as penalties for deficiencies, unrecovered replacement capacity costs and/or unrecovered costs associate with the purchase and sale of emergency energy.

The Transmission Customer shall pay (or be paid) the Residual Uplift to the (by the) Transmission Provider in accordance with Section 7 of the Tariff.

ATTACHMENT H

Annual Transmission Revenue Requirement

For Network Integration Transmission Service

1. The rate charges for Network Integration Service will be C$4,154.90 per MW-per month.

   This rate will be applied to the Network Integration Transmission provided for Network Load.

2. The Network Customer's monthly Network Load is its hourly load at the time of the PEI hourly peak load for the month and the Network Customer's monthly Network Load includes all electrical consumption regardless of source including losses and also includes its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3 of the OATT.