7.0 CALCULATION OF TRANSMISSION SERVICE RATES BASED ON HISTORICAL DATA

Maritime Electric's interim OATT rates are based on historical 2005 year data (taken from Maritime Electric's 2006 Cost of Service 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 the City of Summerside would be taking Network Service.

The rates in Maritime Electric's current proposed OATT for this filing are based on historical 2014 year cost data (taken from Maritime Electric's 2014 Cost Allocation Study) plus the actual transmission system usage for 2014.

The following Table 2 shows how the transmission system revenue requirement has been allocated among the various users for the existing interim OATT rates and for the current proposed OATT (the calculation for the current proposed OATT is shown in Appendix A). This revenue requirement includes all transmission asset related costs (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	**2014 Revenue Requirement**	**2005 Revenue Requirement**
Miscellaneous Designated Facilities	$ 54	$ 28
Maritime Electric -Contracted Wind Related	1,121	--
Merchant Wind Related	325	--
OATT Related (shared by all users)	8,766	5,772
City of Summerside Related	--	5
Energy Control Centre Related	298	248
Total	**$ 10,563**	**$ 6,053**

Table 3 Network and Point to Point Transmission System Usage (MW)		
Type of Service	**2014 Firm Service or Equivalent**	**2005 Firm Service or Equivalent**
Long Term Firm Point-to-Point	--	--
Maritime Electric Network (average 12 CP)	189.0	161.3
Summerside Network (average 12 CP)	--	17.6
Summerside Short-Term Firm	10.0	--
Summerside Non-Firm	6.7	
Merchant Wind Non-Firm (based on non-Appalachian pricing)	33.7	34.2
Total	**239.4**	**213.1**

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 has again proposed that the transmission service rates (but not the rates for Ancillary Services) for exporting to off-Island should 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 in 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 below.

Table 4 Calculation of Rate for Long Term Firm Service (Point to Point or Network)		
	2014	**2005**
Revenue Requirement ($ thousands)	8,766	5,772
Firm transmission service or equivalent (MW)	239.4	213.1
Rate ($/MW-year)	**36,619**	**27,086**

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

A summary of the rates for services in Maritime Electric's proposed OATT is shown in Table 5 below, along with the existing interim rates. The proposed rates shown for Schedules 3, 5 and 6 (the Capacity-Based Ancillary Services) are the NB Power OATT values, effective August 1, 2015, and are shown here for reference. Maritime Electric proposes that Schedules 3, 5 and 6 in its OATT will point 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 ($/MW-month)	Existing Interim ($/MW-month)
Scheduling, System Control and Dispatch	1	Appendix F	95.70	89.48
Reactive Supply and Voltage Control from Generation Sources	2	Appendix H	127.97	144.68
Regulation (Automatic Generation Control)	3(a) (1)	NB OATT	8,321 (2)	52
Load Following	3(b) (1)	NB OATT	8,287 (2)	120
AGC and Load Following for Non-Dispatchable Wind	3(c) (1)	NB OATT	$0.29/MWh	$0.50/MWh
Energy Imbalance	4	Section 6.3	n/a	n/a
Operating Reserve – Spinning	5 (1)	NB OATT	8,276 (2)	127
Operating Reserve – Supplemental (10 minute)	6(a) (1)	NB OATT	5,383 (2)	237
Operating Reserve – Supplemental (30 minute)	6(b) (1)	NB OATT	5,383 (2)	338
Point-to-Point Transmission Service	7 and 8	Appendix D	3,052	2,257
Residual Uplift	10	Section 6.3	n/a	n/a
Network Transmission Service	Att. H	Appendix E	3,052	2,257

1. These rates are from NB Power's OATT.
2. These rates are now based on MW of generating capacity obligation rather than MW of transmission service as had previously been the case.

APPENDIX A - Revised March 2018
ALLOCATION OF YEAR 2014 TRANSMISSION COSTS BY FUNCTION
(000's)

		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 O&M	Allocations of OM&A: General by gross plant	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 2014 Cost Allocation Study					$ 1,922		$ 3,693				$ 3,580	$ 9,195	$ (19)	$ 9,176
Less adjustments					(72)		-				-	(72)	-	(72)
Total Tranmission Costs from 2014 Cost Allocation Study after Adjustments					**$ 1,850**		**$ 3,693**				**$ 3,580**	**$ 9,123**	**$ (19)**	**$ 9,104**
Plus NB Schedule 9 charge for Interconnection Upgrade Project							1,159							1,159
Plus replenishment of submarine cables contingency fund							300							300
							5,152							10,563
Miscellaneous designated amounts														
- substations (for MECL generation)		$ 380	$ 344	$ 36	$ 8	$ 9		$ 3	$ 7	$ 10	$ 3	$ 22		$ 22
- substations (other)		133	12	121				1	2	3		3		3
- lines (other)		369	78	291				8	7	14		14		14
- telecommunications (other)		357	150	207				8	6	14		14		14
		1,240	585	655	8	9	-	20	22	42	3	54		54
Designated for MECL wind purchases														
- substations		3,261	146	3,115	75	88		24	58	82	287	457	(2)	455
- lines		4,483	584	3,899	103	121		94	80	174	359	654	(2)	652
- telecommunications		82	34	48	5	6		2	1	3	4	13	(0)	13
		7,826	765	7,062	183	215	-	120	139	259	650	1,124	(3)	1,121
Designated for IPP merchant wind														
- substations		1,441	205	1,236					26	26		26		26
- lines		16,497	1,952	14,545	1	1	1	-	293	294	2	296		296
- telecommunications		129	54	75					2	2		2		2
		18,068	2,212	15,856	1	1	1	-	321	322	2	324		324
OATT transmission facilities														
- interconnection (before upgrade)							748			748		748		748
- NB Sch 9 charge for intercon. Upgrade							1,159			1,159		1,159		1,159
- submarine cables contingency fund							300			300		300		300
- substations		22,591	9,706	12,885	512	603		168	402	570	1,186	2,359	(6)	2,352
- lines		33,109	15,082	18,027	754	888		693	589	1,282	1,659	3,829	(9)	3,820
- telecommunications		1,441	849	591	86	102		32	26	58	54	214	(0)	214
- OATT administration		-	-	-	-	-	172	-	-	172	-	172	-	172
		57,141	25,638	31,503	1,352	1,593	2,379	894	1,017	4,290	2,899	8,781	(16)	8,766
Energy Control Centre		559	276	283	27	32	229		10	239	26	298		298
Unassigned O&M	Allocated by:													
- substation O&M	-substation gross plant						196	(196)		-				-
- lines O&M	- lines gross plant						795	(795)		-				-
- telecommunications O&M	- tele. gross plant						42	(42)		-				-
										-				-
Indirects										-				-
- Insurance	- gross plant with General						185		(185)	-				-
- Vehicles		1,465	459	1,006	110	-	-		-	-				-
- General	- gross plant	1,796	558	1,238	170	-	1,324		(1,324)	-				-
Totals		$ 88,094	$ 30,491	$ 57,602	$ 1,850	$ 1,850	$ 5,152	$ -	$ -	$ 5,152	$ 3,580	$ 10,582	$ (19)	$ 10,563

APPENDIX C

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

Services	Total usage by service (MW)	Total usage by service %	Total Cost Allocated to OATT Transmission Facilities (000's)	Total Allocated cost by service (000's)	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	50.3	21%	$ 8,766	$ 1,843	$ 36,619	$ 3,051.60
OATT Network	189.0	79%	$ 8,766	6,923	$ 36,619	$ 3,051.60
Subtotal Transmission Services	239.4	100%		8,766	$ 36,619	$ 3,051.60
Misc. designated amounts				54		
MECL wind purchases				1,121		
IPP merchant wind				324		
Schedule 1 Sched, Sys Control & Dispatch	259.0	100%	$ 298	298	$ 1,148	$ 95.70
Total				$ 10,563		

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

APPENDIX D
RATES FOR POINT TO POINT TRANSMISSION SERVICE
SCHEDULES 7 & 8

Total annual cost by class	(Appendix C)	$ 1,843	(000's)
Total usage by class (1)	(Appendix B)	50.3	MW
Yearly (2) (same as for Network Service)		36,619.25	$ / MW - yr
Monthly (3)	= Yearly / 12	3,051.60	$ / MW - mo
Weekly (3)	= Yearly / 52	704.22	$ / MW - wk
On-peak daily (3) (5)	= Weekly / 5	140.84	$ / MW - day
Off-peak daily (3)	= Yearly / 365	100.33	$ / MW - day
On-peak hourly (4) (5)	= On-peak daily / 16	8.80	$ / MWh
Off-peak hourly (4)	= Yearly / 8,760	4.18	$ / 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
Attachment H

Total annual cost by class	(Appendix C)	$ 6,923	(000's)
Total usage by class (average of 12 CP)	(Appendix B)	189.0	MW
Yearly		36,619.25	$ / MW - yr
Monthly	= Yearly / 12	3,051.60	$ / MW - mo

Integration Transmission Service over the Transmission Provider's Transmission System.

Maritime Electric as a Transmission Customer taking Network Integrated Transmission Service, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any other Network Customer under Part III of this OATT. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to have constructed and placed into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to that used by the Transmission Provider in its Transmission System planning for Maritime Electric Native Load Customers.

28.3 Network Integration Transmission Service

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to Maritime Electric's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service

The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the OATT. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-to-Point Transmission Service under Part II of the OATT.

28.5 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are based on monthly system average losses. The system average loss factor for each month will be posted ~~is calculated annually and provided~~ on the Transmission Provider's website.

28.6 Restrictions on Use of Service

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-to-Point Transmission Service under Part II of the OATT for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load. Penalties will apply as per sections 13.9 and 14.8.

29 INITIATING SERVICE

29.1 Condition Precedent for Receiving Service

Subject to the terms and conditions of Part III of the OATT, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided

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.

~~The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the~~

~~scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.~~

~~For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last MW 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.

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$36,619.25/MW of Reserved Capacity per year.

2. Monthly Delivery: C$3,051.60/MW of Reserved Capacity per month.

3. Weekly Delivery C$704.22/MW of Reserved Capacity per week.

4. On-Peak Daily Delivery: C$140.84/MW of Reserved Capacity per day.

5. Off-Peak Daily Delivery: C$100.33/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$3,051.60/MW of Reserved Capacity per month.
2.	Weekly delivery:	C$704.22/MW of Reserved Capacity per week.
3.	On-Peak Daily delivery:	C$140.84/MW of Reserved Capacity per week.
4.	Off-Peak Daily delivery:	C$100.33/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$8.80/MW of Reserved Capacity per hour.
6.	Off-Peak Hourly delivery:	C$4.18/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 = 1.79%

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$1.576	million/year
Fixed Assets (Gross Book Value)	C$88.094	million
OM&A ÷ Fixed Assets	1.79	%

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.

ATTACHMENT H

Annual Transmission Revenue Requirement
For Network Integration Transmission Service

1. The rate charges for Network Integration Service will be C$3,051.60 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.

ATTACHMENT I

Index of Network Integration Transmission Service Customers

The index of Network Integration Transmission Service Customers is posted on the Transmission Provider's website.

4.2.3 The Transmission Provider shall use the Baseline Plan as the basis for the determination of incremental, decremental, deferred, or advanced costs as required in allocating costs associated with transmission expansion. Any such allocation shall be performed in compliance with the OATT.

4.2.4 The Transmission Provider shall convene a meeting of the Users Group prior to preparation of the Baseline Plan. Users Group members will be provided an opportunity to discuss the data, information and assumptions that will be used to develop the Baseline Plan. Users Group members shall be provided with at least 7 days notice of the time and location of this meeting.

4.3 Periodic Assessment of the Integrated Electricity System

4.3.1 The Transmission Provider shall perform a periodic assessment to identify the potential need for investments in Transmission Facilities and other actions that may be required to maintain Reliability of the IES, and to reduce the costs associated with transmission congestion on the IES. Where applicable, each such assessment shall identify the impact of existing and emerging shortages of transmission capacity on the IES, any significant existing, emerging or potential transmission congestion on the IES, the impact of the connection of new or modified Facilities and the Adequacy of Interconnections.

4.3.2 Where the Transmission Provider has identified in an assessment the need to alleviate existing or emerging transmission congestion on the IES, it shall develop and study technically feasible options for alleviating the constraint in consultation with Users Group members. Such consultation will be conducted through the process established under Section 4.1.2 of this Attachment.

4.3.3 By February 28th of each calendar year, Users Group Members and potential new Transmission Customers are requested to submit to the Transmission Provider any projections that identify a need for Transmission service over the next 10 years. Such good faith projections of a need for service, even though they may not yet be subject to a transmission reservation, are useful in transmission planning. Such projections may be used to determine potential transmission congestion on the IES.

4.3.4 Where an assessment referred to in Section 4.3.1 identifies potential transmission congestion on the IES, the Transmission Provider may, depending upon the nature and the probability of the congestion,

a. utilize the process as described in Section 4.3.2; or

b. request further supporting information.

4.3.5 For the purposes of this section, transmission congestion shall be considered to be emerging if it is identified by the Transmission Provider as likely to arise within one to five years and transmission congestion shall be considered to be potential if it is identified by the Transmission Provider as likely to arise, which may be based upon good faith projections of interested parties of Section 4.3.3 within five to ten years.

4.3.6 The Transmission Provider will accept projections that identify a need for transmission service driven by Public Policy Requirements; or, for regional planning activities, a list of studies that meet regional needs and opportunities, including needs driven by Public Policy Requirements.

4.4 Economic Planning Studies

4.4.1 The Transmission Provider shall undertake economic planning studies on behalf of native load or OATT customers. Economic planning studies shall evaluate potential upgrades or other investments that could reduce congestion or integrate new resources and loads. Generally, the studies will be conducted in connection with other planning studies.

4.4.2 Users Group members and potential new Transmission Customers may submit written requests for economic planning studies to the Transmission Provider. Such requests shall specify in detail the specific proposed project to be the subject of the requested economic planning study.

4.4.3 The Transmission Provider, with due consideration of priorities identified by parties under Section 4.4.2, shall identify a maximum of two high priority economic planning studies, with no minimum, that will be performed on behalf of stakeholders within a calendar year. Any formal protest of the studies identified shall be in accordance with the Dispute Resolution Procedure of the Transmission Provider's OATT.

4.5 Coordinated Transmission Planning

4.5.1 As a member of MATPC the Transmission Provider will participate in coordinated planning with interconnected systems through Annual Area Reviews as outlined in NPCC Regional Reliability Reference Directory 1, Design and Operation of the Bulk Power System.

4.5.2 The Transmission Provider will post current links on its public website to NPCC's procedures and guidelines, as well as information detailing the Transmission Provider's participation in NPCC's planning process.

4.5.3 Through the Transmission Provider's participation in NPCC, data sharing and information exchange will take place with interconnected transmission systems and in coordinated planning studies that may have interregional impacts.

4.5.4 The Transmission Provider will post on its website how Users Group members and potential new Transmission Customers can obtain information with respect to opportunities for participation in interregional planning forums.

5.0 CONNECTION OF NEW AND MODIFIED FACILITIES

5.1 Connection Requirements of New and Modified Facilities

5.1.1 All new or modified Facilities must be approved by the Transmission Provider before connecting to the IES.

5.1.2 Each Generation Facility that is connected to the IES must be the subject of a Connection Agreement substantially in the form of existing agreements filed with IRAC as set forth in Attachment J, Generation Interconnection Agreement.

5.1.3 Each Load Facility, including for greater certainty a Distribution System, that is connected to the IES must be the subject of a connection agreement with the Transmission Provider in substantially the form of the Attachment G, Network Operating Agreement.

5.1.4 Each new Facility that is connecting to the IES shall comply with the applicable technical requirements defined in the Transmission Providers Facility Connection Requirements.

5.2 General Connection Assessment Process for New or Modified Generation and Interconnection Facilities

5.2.1 A person that wishes to connect a new or modified Facility to the IES shall file a Request for Connection Assessment with the Transmission Provider in the form set forth in the Connection Assessment Procedure (Appendix K-1 to this Attachment K), together with the supporting materials and deposit.

5.2.2 The Transmission Provider shall assign a priority to each Request for Connection Assessment that it receives based on the date of receipt of the completed Request for