MARITIME ELECTRIC
A FORTIS COMPANY

July 8, 2016

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

Dear Commissioners:

Please find enclosed 10 copies of Maritime Electric's Open Access Transmission Tariff Application and Evidence for approval of a revised Tariff to be effective January 1, 2017. An electronic copy will be forwarded shortly.

If you require further information, please do not hesitate to contact me at (902) 629-3668.

Yours truly,

MARITIME ELECTRIC

Angus Orford

Angus S. Orford
Vice President,
Corporate Planning & Energy Supply

ASO07
Encl. as noted

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 Open Access Transmission Tariff for the period beginning January 1, 2017 and for certain approvals incidental to such an order.

APPLICATION AND EVIDENCE
OF
MARITIME ELECTRIC COMPANY, LIMITED

Date: July 8, 2016

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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 the Open Access Transmission Tariff ("OATT") as outlined in the attached evidence for the period beginning January 1, 2017.

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 John David Gaudet and Angus Sumner Orford contains the evidence in which Maritime Electric relies in this Application.

Dated at Charlottetown, Province of Prince Edward Island, this 8th day of July, 2016.

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

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AFFIDAVIT

We, John David Gaudet 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 10 inclusive and Appendices A through L 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 8th day of July, 2016.
Before me:

John D. Gaudet

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. The Company's head office is located in Charlottetown with generating facilities in Charlottetown and Borden-Carleton. 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 two submarine cables leased from the Prince of Prince Edward Island. The Company purchases 92.5 MW of wind powered energy through contracts with 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 is the evidence in support of the Company's proposed updates to the OATT to reflect changes since the original filing in November 2006.

The Company's proposed updates cover two main areas. The first area is updates to the text of the OATT document to reflect changes in the electric power industry generally since 2006. The proposed updates are explained in the evidence of Mr. W. K. Marshall which is attached as Appendix J. The updates are mainly in regards to:

- Aspects of Federal Energy Regulatory Commission ("FERC") Orders 889 and 890 have been incorporated;
- Maritime Electric's OATT document generally aligns with FERC Orders 888, 889 and 890 as well as other FERC orders;
- Maritime Electric's OATT document closely follows NB Power's OATT where NB Power has received approval from the New Brunswick Energy and Utilities Board to deviate from FERC; and

- The transmission planning process has been formalized.

The second main area of updates is to the various charges for services under the OATT. These updates are explained in Sections 7 to 9 below. Generally, Maritime Electric's interim approved OATT charges (see Order UE08-03 as amended by Order UE09-06) are based on year 2005 cost data. The proposed updated charges are based on year 2014 cost data.

The Company is seeking approval from the Commission of the revised OATT for the period beginning January 1, 2017 which is included as Appendix K of this filing and for certain approvals incidental to such an order.

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 its transmission system for serving its own load.

This Evidence summarizes the approach followed by Maritime Electric to develop its OATT rates. Maritime Electric's approach closely follows NB Power's approach which in turn is based on the United States FERC Pro Forma Tariff.

The current situation in PEI has Maritime Electric supplying 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. Since 2002, Summerside has been purchasing its electricity supply from off-Island sources and Maritime Electric has been providing transmission wheeling service for the City. 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 and merchant wind power developers in 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 the City of Summerside 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 has now updated its proposed OATT to reflect changes since the November 2006 filing, and is refiling the proposed OATT for approval by IRAC for the period beginning January 1, 2017.

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. In 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 the City of 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**]
- 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 PROPOSED OATT

6.1 Transmission Service Rates in the Maritime Electric OATT

Table 1 below shows the rate for long term firm Point to Point Transmission Service in Maritime Electric's interim OATT and in Maritime Electric's current proposed OATT as well as the corresponding rates in the New Brunswick, Nova Scotia and Maine Public Service OATTs (The Maine Public Service load is in northern Maine and is approximately ½ the size of the PEI load. Northern Maine is interconnected with New Brunswick but is electrically isolated from the rest of the State of Maine).

Table 1
Rates for Long Term Firm Point-to-Point Transmission Service

Jurisdiction	($/MW-year)
New Brunswick	24,882 [effective August 1, 2015]
Nova Scotia	59,876 [2014 rates, from OASIS[1]]
Maine Public Service ($ US)	34,560 [effective June 1, 2015]
Maritime Electric existing interim OATT	27,086
Maritime Electric proposed OATT	30,523

1. Open Access Same Time Information System ("OASIS")

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 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 in the Maritime Electric OATT

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:

    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**]

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 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. 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 interim 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 which 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 normally self-supply their 10-minute and 30-minute Supplemental Reserve requirements.

For the Maritime Electric OATT, Maritime Electric is again proposing to use the same rates for Capacity-Based Ancillary Services as are in the NB Power OATT. 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 in the Maritime Electric OATT

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**]
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 to produce or absorb reactive power as needed in order to maintain transmission system voltages within acceptable limits. At the time of the 2014/15 PEI winter peak, an estimated 15 MVAr were required from Maritime Electric's on-Island generators and a further 29 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 provide Energy Imbalance Service because for most of the year it does not run on-Island generators which could be used to regulate the energy flow on the NB/PEI interconnection. 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 Under the Maritime Electric OATT

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 the City of Summerside Electric Department.
- Apart from the City of Summerside, 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 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)	7,307	5,772
City of Summerside Related	--	5
Energy Control Centre Related	298	248
Total	**$ 9,104**	**$ 6,053**

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.

The 2014 Revenue Requirement column in Table 2 shows no Summerside related allocation. In Maritime Electric's 2006 OATT filing the costs associated with the 69 kV transmission line designated as T-11 which connects Summerside's Substation to Maritime Electric's Sherbrooke Substation, had been allocated solely to Summerside. Maritime Electric is now proposing to include T-11 (including losses) with the OATT related facilities, so as to put Summerside on the same basis as Maritime Electric's customers.

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 megawatts (MW). Table 3 below shows the combined transmission system usages that were used for calculating the existing interim rate for transmission service and the proposed rate for transmission service (details of the calculations for the current proposed OATT are shown 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	**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)	7,307	5,772
Firm transmission service or equivalent (MW)	239.4	213.1
Rate ($/MW-year)	**30,523**	**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	2,544	2,257
Residual Uplift	10	Section 6.3	n/a	n/a
Network Transmission Service	Att. H	Appendix E	2,544	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.

8.0 SCHEDULE 9 – NON-CAPITAL SUPPORT CHARGE

Schedule 9 is for OM&A charges to designated transmission facilities for which a contribution in aid of construction was provided. Under Schedule 9, direct O&M 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 below.

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

Transmission System Related	**2014 Data**	**2005 Data**
General Expenses (from Cost Allocation Study)	1,324	972
Plus Insurance	185	included above
Plus Property taxes	67	included above
Total General Expenses	1,576	972
Maritime Electric gross fixed assets (mid-year for 2014)	88,094	43,997
Plus direct assignment facilities to mid-2007	included above	6,598
Total gross fixed assets	88,094	50,595
General expenses as per cent of gross fixed assets	**1.79%**	**1.92%**

9.0 SYSTEM LOSSES

Currently transmission losses for Summerside and the West Cape wind farm are approximately 2.8 per cent based on a path specific calculation done monthly and on an interim basis.

Maritime Electric is proposing to apply losses on a postage stamp basis for transmission system usage. The percentage losses for the current month would be set equal to the actual value for the same month in the previous year. Average transmission system losses were 2.7 per cent in 2014.

10.0 IMPLEMENTATION OF STANDARDS OF CONDUCT

FERC Order 889 requires the Transmission Provider to have in place Standards of Conduct, the purpose of which is to prevent the Transmission Provider from giving undue preference to its wholesale merchant function or any affiliated marketing entity that might seek access to their transmission network. The Standards of Conduct achieve this by functionally separating transmission service employees from those affiliated employees who engage in merchant transactions, and by requiring that access to the transmission network be non-discriminatory through an Open Access Same Time Information System ("OASIS").

Maritime Electric has transmission function employees who must be subject to the Standards of Conduct, but their interaction is with only one Network customer and two Point-to-Point customers. Also, Maritime Electric does not conduct any day-to-day marketing, and so has no employees who should be designated as market function employees. (Their merchant function is limited to arranging purchases to supply their native load customers.)

Maritime Electric's proposed Standards of Conduct are based on those of NB Power. Following the lead of the FERC and NB Power, Maritime Electric also proposes that the Standards of Conduct be removed from the OATT and posted separately on its web site. Maritime Electric is filing its proposed Standards of Conduct along with the proposed OATT for suggested concurrent review and approval by IRAC as Appendix L.

The terms and conditions regarding Maritime Electric's proposed OASIS are set out in Attachment P of the OATT. Given that Maritime Electric has just one Network customer and two Point-to-Point customers and no internal marketing function activity, Maritime Electric proposes that all of the information and processing required for providing non-discriminatory transmission access will be provided manually through the Maritime Electric OATT administrator and posted on the Maritime Electric OASIS. This is believed to be the most economically efficient approach at this time.

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 Open Access Transmission Tariff for the period beginning January 1, 2017 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 interim Open Access Transmission Tariff, as approved by the Commission in Order UE08-03, and amended in Order UE09-06, is further amended. Effective January 1, 2017, the Open Access Transmission Tariff detailed in the Evidence

and attached hereto as Appendix K is approved and shall continue effective until otherwise ordered by the Commission.

2. Maritime Electric apply system losses on a postage stamp basis for transmission system usage. The percentage losses for the current month would be set equal to the actual value for the same month in the previous year.

3. Maritime Electric Standards of Conduct be removed from the OATT and posted separately on its web site as filed for concurrent review and approval by IRAC.

4. All of the information and processing required for providing non-discriminatory transmission access will be provided manually through the Maritime Electric OATT administrator and posted on the Maritime Electric OASIS as this is considered to be the most economically efficient approach at this time.

DATED at Charlottetown, Prince Edward Island, this ___ day of _____, 2016.

BY THE COMMISSION:

____

Chair

____

Commissioner

____

Commissioner

____

Commissioner

APPENDIX A
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**
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		-	-	-	-	-	748	-	-	748	-	748		748
- 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	920	894	1,017	2,831	2,899	7,322	(16)	7,307
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**	**$ 3,693**	**$ -**	**$ -**	**$ 3,693**	**$ 3,580**	**$ 9,123**	**$ (19)**	**$ 9,104**

APPENDIX B
DEMAND DETERMINANTS FOR 2014

Services		2014 usage (MW)	2014 usage (MWh)		Transmission Service equivalent firm (MW)			Schedules 1 and 2 equivalent firm (MW)	
Long term firm Point-to-Point reservations		-		**A**	-			-	
Average of 12 CP for MECL load (Network)		189.0		**B**	189.0			189.0	
Average of 12 CP for Sside load (Network)		-		**C**	-			-	
Short term firm Point-to-Point service:									
- Summerside	(average for 12 months)	10.0		**D**	10.0			10.0	
Non-firm Point-to-Point service:									
- Summerside	on-peak		24,621	**E**	5.9	*		5.9	*
	off-peak		6,856	**F**	0.8			0.8	
- Merchant wind	on-peak		155,799	**G**	17.8	**		37.5	*
	off-peak		138,859	**H**	15.9			15.9	
					239.4		**I**	259.0	

<u>TOTAL TRANSMISSION SERVICE USAGE BY SERVICE:</u>

OATT Network	**(B + C)**	189.0
OATT Point to Point	**(A + D + E + F + G + H)**	50.3
		239.4

<u>TOTAL SCHEDULES 1 & 2 :</u> I 259.0

***** Appalachian (divide the usage in MWh by 4,160 on-peak hours in the year (16 hours/day X 5 days/week X 52 weeks/year))
****** Non-Appalachian (divide the usage in MWh by 8,760 hours in the year (24 hours/day X 365 days/year))
The calculation for off-peak is the same as for non-Appalacian.

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%	$ 7,307	$ 1,536	$ 30,523	$ 2,543.58
OATT Network	189.0	79%	$ 7,307	5,770	$ 30,523	$ 2,543.58
Subtotal Transmission Services	239.4	100%		7,307	$ 30,523	$ 2,543.58
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				$ 9,104		

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)	$ 1,536	(000's)
Total usage by class (1)	(Appendix B)	50.3	MW
Yearly (2) (same as for Network Service)		30,522.91	$ / MW - yr
Monthly (3)	= Yearly / 12	2,543.58	$ / MW - mo
Weekly (3)	= Yearly / 52	586.98	$ / MW - wk
On-peak daily (3) (5)	= Weekly / 5	117.40	$ / MW - day
Off-peak daily (3)	= Yearly / 365	83.62	$ / MW - day
On-peak hourly (4) (5)	= On-peak daily / 16	7.34	$ / MWh
Off-peak hourly (4)	= Yearly / 8,760	3.48	$ / 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)	$ 5,770	(000's)
Total usage by class (average of 12 CP)	(Appendix B)	189.0	MW
Yearly		30,522.91	$ / MW - yr
Monthly	= Yearly / 12	2,543.58	$ / MW - mo

APPENDIX F
RATES FOR SCHEDULING, SYSTEM CONTROL & DISPATCH SERVICE
SCHEDULE 1

Total annual cost for Energy Control Centre	(Appendix A)	$ 298	(000's)
Total usage	(Appendix B)	259.0	MW

For Point to Point Service (1)

Yearly (2)		1,148.45	$ / MW - yr
Monthly (3)	= Yearly / 12	95.70	$ / MW - mo
Weekly (3)	= Yearly / 52	22.09	$ / MW - wk
On-peak daily (3)	= Weekly / 5	4.42	$ / MW - day
Off-peak daily (3)	= Yearly / 365	3.15	$ / 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		1,148.45	$ / MW - yr
Monthly	= Yearly / 12	95.70	$ / 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

APPENDIX G
REVENUE REQUIREMENT FOR REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE
FROM GENERATION SOURCES

	Capacity (MVAr)	Capital cost ($ millions)		Capital cost ($ / MVAr)	Annual O&M ($)	
	A	B		C= B X 1,000,000 / A	D	
Proxy unit for NB Power Tariff calculation	150	24.6		164,000	150,000	
Proxy unit for MECL Tariff calculation	50	11.4	*	228,024	69,519	**

Expected service life	45	years
MECL annual fixed charges rate (APPENDIX I)	7.32	%

Estimated annual cost for a 50 MVAr synchronous condenser:

Capital related	834,567	$ / yr	(7.32% of $11.4M in Column B)
O&M	69,519	$ / yr	Column D
Total	904,087	$ / yr	
Per unit cost	18,082	$ / MVAr - yr	($904,087 / 50 MVAr)
Adjusted per unit cost (X 50%)	**9,041**	**$ / MVAr - yr**	

Note: Adjusted per unit cost is 50 % of per unit cost of the synchronous condenser because it could also function as a synchronous generator if driven by a prime mover, and thus provide energy production as well as the reactive supply and voltage control service.

Estimated MVAr required from on-Island generators at 2014/15 winter peak	15	MVAr
Additional requirement for loss of a 138 kV line in New Brunswick	29	MVAr
Total MVAr requirement from on-Island generators	**44**	**MVAr**

Annual revenue requirement of Reactive Supply and Voltage Control **= 44 MVAr x 9,041 $ / MVAr - yr**

= 397,798 $ / yr

* NB Power Capital Cost X (MECL MVAr / NB Power MVAr) ^ 0.7, with the 0.7 exponent used to reflect economies of scale.
** NB Power Annual O & M X (MECL MVAr / NB Power MVAr) ^ 0.7, with the 0.7 exponent used to reflect economies of scale.

APPENDIX H
RATES FOR REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE
FROM GENERATION SOURCES
SCHEDULE 2

Total annual cost	(Appendix G)	$ 398	(000's)
Total usage	(Appendix B)	259.0	MW

For Point to Point Service

Yearly		1,535.61	$ / MW - yr
Monthly	= Yearly / 12	127.97	$ / MW - mo
Weekly	= Yearly / 52	29.53	$ / MW - wk
On-peak daily	= Weekly / 5	5.91	$ / MW - day
Off-peak daily	= Yearly / 365	4.21	$ / MW - day
On-peak hourly	= On-peak daily / 16	0.37	$ / MWh
Off-peak hourly	= Yearly / 8,760	0.18	$ / MWh

For Network Service

Yearly		1,535.61	$ / MW - yr
Monthly	= Yearly / 12	127.97	$ / MW - mo

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

APPENDIX I

MECL ANNUAL FIXED CHARGE RATE FOR SYNCHRONOUS CONDENSER

1. Capitalization:

- Debt	60.00 %	@	4.25 %	=	2.55
- Common equity	40.00 %	@	9.35 %	=	3.74
- Weighted average cost of capital (r)					6.29

2. Capital recovery factor (f): 45 years @ 6.29 %

$$\frac{r(1 + r)^n}{(1 + r)^n - 1} = 6.72$$

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

$$\frac{f \times 100 \times i}{r + i} = 3.76$$

4. Future income tax: @ 31.00 % tax rate

- Levelized capital cost allowance		3.76
- Less str line amortization @	45 years	2.22

0.31 x 1.54 = 0.48

5. Levelized cost of debt:

- Capital recovery factor	6.72
- Less straight line amortization	2.22
- Less future income tax	0.48
	4.02

- Levelized cost of debt = $\frac{2.55}{6.29} \times 4.02 = 1.63$

6. Levelized current income tax:

- Capital recovery factor	6.72
- Less levelized capital cost allowance	3.76
- Less levelized cost of debt	1.63
	1.33

- Income tax payable $\frac{1.33}{1 - 0.31} \times 0.31 = 0.60$

7. Annual fixed charges rate:

- Capital recovery factor	6.72
- Plus current income taxes payable	0.60
- Total	7.32

EVIDENCE OF

WILLIAM K. MARSHALL

ON BEHALF OF

MARITIME ELECTRIC COMPANY LIMITED

ISLAND REGULATORY AND APPEALS COMMISSION

APPLICATION OF MARITIME ELECTRIC COMPANY LIMITED FOR APPROVAL OF ITS TRANSMISSION TARIFF AND TRANSMISSION REVENUE REQUIREMENTS

June 30, 2016

Table of Contents

Evidence of William K. Marshall

MECL Open Access Transmission Tariff

I INTRODUCTION

William K. Marshall was engaged through his company WKM Energy Consultants Inc ("WKM") by Stewart McKelvey to review the existing Maritime Electric Company Limited ("MECL") Open Access Transmission Tariff ("OATT"), compare it to the United States Federal Energy Regulatory Commission ("FERC") *Pro Forma* OATT, compare it to the OATTs of Canadian utilities with FERC compatible OATTs, make recommendations regarding modifications that should be made to the MECL OATT to bring it up to current industry standards appropriate for Prince Edward Island, and to assist MECL with the preparation of a redlined version of the current OATT. The detailed scope of work under the engagement is provided as Attachment B to this report.

The principal of WKM is William K. (Bill) Marshall. Bill's career includes eight years teaching at the secondary and college level and 36 years in industry – mainly as a power system planner, corporate strategist and policy advocate with NB Power for 24 years. From 2004 – 2008, he was President and CEO of New Brunswick System Operator (NBSO) where he established the organization and positioned it to become the central transmission organization and Reliability Coordinator of the Maritimes Area. Since his retirement from NBSO, Bill has been acting as an independent energy consultant, has regularly made presentations on Atlantic Canada power issues at regional conferences and has been recognized as an expert in planning and operations of power systems and transmission tariffs by different regulators.[1] Bill holds Bachelor degrees in Electrical Engineering and Education and a Master's degree in Power Systems Engineering. His resume is provided in Attachment A.

This report provides some background information regarding the development and rational for open non-discriminatory access to transmission systems and reviews the current MECL OATT in that light. It is the opinion of WKM that the current MECL interim OATT generally complies with FERC standards that existed prior to 2003. It is also generally compatible with the OATTs of other Canadian utilities. However, there have been several FERC rulings since 2003, most notably Order 890, that are not addressed in the current OATT. In order to maintain compatibility with the current state of the power industry WKM sets out proposals to modify the MECL OATT. These proposals are discussed under five general groupings as follows:

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[1] NB Energy and Utilities Board (NBEUB) for the NB OATT case in 2015, Nova Scotia Utilities and Review Board (NSUARB) for the Maritime Link case in 2013, and the Régie de l'énergie of Québec for the Hydro Quebec Transmission Tariff in 2011 and for a Hydro Quebec Wind Integration Service in 2014

a. Cost Allocation and Rate Design,
b. General Terms and Conditions of the OATT,
c. Real Power Losses, System Costs/Credits and Discounts,
d. Standards of Conduct, and
e. Open Access Sametime Information System ("OASIS")

In discussing the various FERC orders in this report it is proposed that all changes be implemented unless specifically stated that a deviation from FERC policy should be considered. To provide a transparent indication of the changes to the terms and conditions of the current MECL OATT a redlined version of the proposed OATT is provided as a separate Attachment in the MECL filed evidence. Those redline changes are consistent with the findings in this report.

II BACKGROUND

Open transmission access under an OATT is "*the foundation upon which competition in electricity supply can occur. It opens the transmission system to all users under consistent non-discriminatory terms and conditions, and charges rates based on the cost of providing services*".[2] Such open non-discriminatory access to transmission systems has been evolving in North America since the landmark Order 888 of FERC in 1996.

FERC jurisdiction in the United States applies to utilities that are subject to sections 205 and 206 of the Federal Power Act ("FPA"). Such utilities are referred to by FERC as public utilities. Non public utilities are defined in Order 890 as entities that *"are not FPA public utilities and therefore are not subject to the Commission's jurisdiction under sections 205 and 206 of the FPA."*[3] These are sometimes also referred to as *"non-jurisdictional utilities"* and include foreign transmission providers as well as US non-public utilities such as federal power authorities and electric cooperatives.

"Although the FERC has no direct jurisdiction outside the United States, it has had significant influence on the implementation and design of external tariffs. First, the FERC has instituted a reciprocity requirement on all non-jurisdictional utilities that use the tariffs of jurisdictional utilities. Second, non-jurisdictional companies wishing to sell electric power at market based [rates] ("MBR") *in the U.S. must acquire a power marketing authority license from the FERC. Thirdly, the license requires that the reciprocal transmission access to be provided is done under a tariff that is equal to or superior to the Pro Forma. The effect of this latter point has lead to the development*

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[2] **NB Power Transmission Tariff Design**, June 2002, page 4, lines 3-6 provided as a separate Attachment D to this evidence report. Note that this Design Report was prepared under the direction of Mr. Marshall when he was the Director of Strategic Planning at NB Power

[3] FERC Order 890, Footnote 111, page 107

and implementation of Pro Forma tariffs by many utilities in Canada.'[4] Consequently, many Canadian utilities with significant exports to FERC regulated markets have chosen to adopt the FERC standards for open access (e.g. Orders 888 and 889 in the late 1990's, and Order 890 and others more recently). Closely following those standards provides assurance that FERC would accept that open access is being provided on a non-discriminatory basis and thereby confirm that the reciprocity conditions for market access have been met.

Immediately following implementation of Order 888 by FERC the three large hydro generating utilities in Canada, BC Hydro, Manitoba Hydro and Hydro Quebec ("HQ"), all implemented OATTs and filed with FERC for MBR status for their marketing affiliates. In the years that followed Saskatchewan Power, New Brunswick Power Corporation ("NB Power"), Nova Scotia Power Incorporated ("NSPI") and MECL all implemented FERC based OATTs and all but MECL acquired FERC MBR status for their marketing affiliates. Transmission access in Alberta and Ontario is open and non-discriminatory but under terms associated with their electricity markets that are different than the FERC *Pro Forma* OATT. Today only Nalcor does not have an OATT in Canada, but after completion of the Maritime Link to Nova Scotia in the next few years, Nalcor is expected to implement a FERC compatible OATT.

The HQ OATT closely followed the FERC *Pro Forma* with two major differences. Rather than supply the native load of HQ Distribution using Network Transmission Service, HQ added a separate Native Load Service to the tariff in Part IV. In addition, the cost allocation methodology implemented then, and continuing today, deviates significantly from FERC standards. More detail on these cost allocation differences will be provided later in the section discussing cost allocation and rate design.

The first implementation of transmission open access in the Maritimes was done by NB Power with its **Out and Through Transmission Tariff** in 1998. It deviated from the FERC *Pro Forma* OATT in two main ways. Firstly, it did not provide any access to internal provincial loads but only to external markets. Secondly, it applied separate costs for interconnection use and network use such that the Through charge was more than the Out charge.[5] This was opposed by HQ and parties in Maine that were required by Maine law to divest ownership of generation from transmission utilities and implement retail markets. HQ refused to provide reciprocal access to its transmission system to NB Power on the grounds that NB Power was discriminating against external transmission customers. The issue was resolved when NB Power agreed to discount the Through charge to be equal to the Out charge and to contractually provide backup and balancing

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[4] **NB Power Transmission Tariff Design**, June 2002 (Attachment D), page 12, lines 20-28

[5] The Out charge was comprised of use of the network plus one interconnection while the Through charge used the network and two interconnections.

services to the Northern Maine Market which was electrically isolated from the rest of Maine.

After the Province of New Brunswick issued a policy[6] to implement an electricity market in the province, NB Power developed an OATT based on the FERC *Pro Forma* as documented in the **NB Power Transmission Tariff Design** report (Attachment D). The NB OATT was filed with the NB regulator[7] in 2002, approved in early 2003 and implemented September 30, 2003. There were a few minor deviations from the then existing FERC *Pro Forma*. One was use of 12 monthly non coincident peak ("12NCP") loads as the metric for Network Service rather than 12 monthly coincident peak ("12CP") loads which is the FERC standard. A second deviation was the use of an open season using net present value of service requests as the ranking criteria rather than a lottery for assigning initial allocation of transmission. These deviations are apparently not inferior to the *Pro Forma* as the NB OATT was accepted in a FERC letter order[8] in 2011following its submission to FERC in regards to a complaint about the MBR status of NB Power Generation Corporation. According to NB Power's expert FERC witness in their recent OATT application to the NB EUB small deviations from the *Pro Forma* OATT would still be acceptable to FERC. Ms. Marlette has stated

> "*FERC does not require, for reciprocity purposes, that the foreign entity have in place an OATT that is identical to the Pro Forma. Rather, FERC's analysis focuses on whether the foreign entity provides open access in a manner that meets FERC's underlying goals of remedying undue discrimination and preference in the provision of transmission service and mitigating of transmission market power".*[9]

NSPI implemented its OATT in 2005 with terms and conditions similar to the NB OATT but utilized path based losses rather than the postage stamp approach applied in the NB OATT. Similarly, MECL utilized the NB OATT as a basis for its application[10] to the Island Regulatory and Appeals Commission ("IRAC") in 2007. It also had some deviations from the NB OATT and the FERC *Pro Forma* but was approved on an interim basis by IRAC in 2009. It is understood by WKM that Summerside Electric ("SE") has major issues with the interim OATT and sought a permit to bypass the MECL system by constructing a new transmission line from SE to the Bedeque

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6 **New Brunswick Energy Policy White Paper**, Department of Natural Resources and Energy, approved by NB Cabinet in December 2000

7 The NB regulator En 2002 was the Public Utilities Commission ("PUB") which has since evolved into the New Brunswick Energy and Utilities Board ("EUB")

8 FERC Docket No. ER08-1439-004, *New Brunswick Power Generation Corp* (Dec. 1, 2011) (delegated letter order).

9 NB Power 2014 OATT filing, Document NBP6.03 NBP(NBEUB) IR-11

10 MECL produced the **MECL Transmission Tariff Rates Design** report November 30, 2006 which is Attachment E to this evidence report. It was modelled on the **NB Power Transmission Tariff Design** report which is included as Attachment D to this Evidence.

substation to access the underwater cables to New Brunswick. It is also understood that the request was denied by IRAC and also denied on appeal to the Prince Edward Island Court of Appeal. Attempts to negotiate a settlement have also failed and the issues are up for consideration in this case before IRAC for approval of revisions to the MECL OATT. It is also understood that after filing of an application for OATT modifications with IRAC there are to be stakeholder consultations.

All of the eastern Canada OATTs were based on FERC standards as of 2002 (and earlier for HQ) but there have been several FERC rulings since that have been made to improve the *Pro Forma* OATT. As stated in Order 890 the general purpose of FERC has been to amend "*the regulations and the Pro Forma open access transmission tariff adopted in Order Nos. 888 and 889 to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential.*"[11]

Hydro Quebec updated its OATT to be more in line with Order 890 in 2011 and NB Power updated its OATT in 2015 after hearings before the NBEUB. As stated by NB Power:

> *"The key driver was, and continues to be, reciprocity, in addition to maintaining MBR authorization for NB Power's marketing affiliate. The NB Power OATT was originally designed (in 2002) to be compatible with FERC's then-existing Pro Forma OATT. To maintain this compatibility and to ensure that NB Power provides Transmission Customers with non-discriminatory, open access transmission service consistent with current North American standards, NB Power proposes that the NB Power OATT be revised where necessary and appropriate to reflect the changes outlined in subsequent FERC orders. Updating the NB Power OATT will increase the certainty that reciprocity and MBR requirements continue to be met, and will provide greater assurance of transmission and market access for all users of the New Brunswick transmission system"*.[12]

Currently MECL is a Transmission Customer of NB Power and has a supply contract with NB Energy Marketing Corporation. That contract was achieved through a competitive bidding process and has contributed to lower rates for MECL customers since 2011. That contract has been extended and will continue to provide MECL with competitively priced supplies until March 2019. Maintaining reciprocity with NB Power is in the public interest of PEI because it ensures that MECL can continue to access competitively priced energy. Supply is possible from other parties in addition to NB Energy Marketing.

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[11] FERC Order 890, February 16, 2007, Summary, page 1

[12] NB Power 2014 OATT filing, Document NBP2.03 – Part A Terms and Conditions, page 7, lines 10-22

MECL does not have a marketing subsidiary with a MBR interest like NB Power but it is owned by Fortis Corporation which also owns other utilities that may in the future have marketing interests in the United States. This makes NB Power's rationale to maintain its OATT as FERC compliant also in the interests of MECL who is an affiliate of Fortis. The remainder of this document examines the modifications required in the MECL OATT to accomplish this end in a manner appropriate for PEI.

III COST ALLOCATION AND RATE DESIGN

This chapter focuses on how FERC orders and principles have been applied in the current MECL interim OATT as documented in the **MECL Transmission Tariff Rates Design** report which is provided as Attachment E. Also, modifications that should be considered for the proposed updated OATT are addressed and MECL's Evidence in support of its OATT Application[13] is reviewed.

In 1994 FERC set out the basic principles that should be met by transmission pricing as follows:

- Transmission Pricing Must Meet the Traditional Revenue Requirement,
- Transmission Pricing Must Reflect Comparability,
- Transmission Pricing Should Promote Economic Efficiency,
- Transmission Pricing Should Promote Fairness, and
- Transmission Pricing Should Be Practical.

While it set out the principles that were desirable, FERC was still open to different pricing arrangements. It did not specify a mandatory method but in the detailed discussion accompanying the first principle FERC set out a simple three step process that should be followed.

> *"First a utility must determine its total company revenue requirement, ... second, a utility must allocate ... the total revenue requirement ... in a manner which appropriately reflects the costs of providing transmission service ... Finally the utility must design rates to recover those allocated costs from each customer class".*[14]

In Order 888 (and subsequent clarifications) FERC provided much greater direction regarding these three steps. The rest of this chapter discusses the details of these three steps and how they should be applied in PEI.

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[13] The document is filed as the evidence of Robert Younker of MECL

[14] **Transmission Pricing Policy Statement**, FERC, Oct 26, 1994

1. Revenue Requirement

The total revenue requirement of a company includes all costs (amortization costs; operation, maintenance and administration costs; finance charges; taxes; and a regulated return on investment) that are to be recovered through sale of services. These total costs would include costs for generation and distribution functions as well as transmission.

For an OATT we need to focus on the transmission system costs but this may not be so simple. For FERC jurisdictional utilities in the United States there is a standard code of accounts so all utilities define transmission costs in the same manner. In Canada that is not the case. Many utilities include generation step up transformers (as does FERC) and substation step down transformers as transmission assets. This has traditionally been for convenience because the transmission maintenance employees do the maintenance on all the large power transformers in the system regardless of their location or function.

Regardless of what is included as transmission assets and costs the requirement of this first step is determination of the transmission system revenue requirement. The more important step is the allocation of the revenue requirement to the different functional uses of the transmission system.

2. Cost Allocation

Transmission assets and their associated costs support four primary functions:

- Connection of generators to the system,
- Delivery into the distribution system,
- Operation of the power system in a reliable manner, and
- Provision of transmission service in, out and through the power system.

Generation Function - There was some initial confusion after FERC Order 888 about allocation of the costs of generator step up ("GSU") transformers. Some utilities included the costs in the revenue requirement for transmission service while others did not. FERC clarified in 1998 that *"a more accurate method of cost recovery is to directly assign the costs of each GSU transformer to the generator to which it is connected*."[15]

This concept of assigning GSU transformer costs directly to generators has been extended to cover all generator related transmission assets ("GRTAs") that connect a generator to the transmission system. This includes any radial connecting transmission lines and a portion of the connecting terminal station because each generator needs a synchronizing breaker to connect to the system. The rationale behind this is that a

[15] FERC document 85FERC61,274, November 1998.

transmission line that is built to connect a generator is a "generation lead" that is used only by that generator and not by a Transmission Customer who wants to deliver energy across the transmission system. Including that cost in the transmission service revenue requirement would be discriminatory to the Transmission Customer. This GRTA assignment applies not just for the FERC *Pro Forma* OATT but has been applied in all Canadian OATTs except that of Hydro Quebec.[16] It is applied in the current MECL interim OATT and proposed again in the MECL updated OATT.

These GRTA costs are handled in different ways in the MECL OATT and are worthy of note. For connection of MECL's thermal generators "*a portion of the substation assets* [as well as the GSUs] *at the Charlottetown and Borden Substations was allocated to the GRTA function.*"[17] For connection of the independently owned wind generation at North Cape the transmission line to connect to the MECL system is owned by PEI Energy Corporation. Its capital cost and associated OM&A are not included in the MECL revenue requirement. For the wind generation at West Cape the capital costs of these transmission lines was directly assigned to the generation owners and the ongoing indirect OM&A costs are collected through Schedule 9 of the OATT. Direct OM&A costs are billed separately as incurred.[18] The transmission line from Church Road to Elmira was constructed to connect the wind farms at East Point and Hermanville/Clearspring but was not directly assigned to the wind generation owners. It is included in the MECL total transmission revenue requirement but is not included in the revenue requirement for Transmission Services.[19] Rather it is included in the cost of service for MECL customers as if it was a GRTA facility paid for through the supply contracts with the wind farms that it connects. As such the costs of all of these GRTA facilities for MECL are not included in the Revenue Requirement for Transmission Services which is compatible with FERC principles.

Distribution Function – Transmission assets and their related costs that should be assigned directly to the distribution function are substations that connect transmission to distribution including the distribution step down transformers. An applied line of demarcation is the high voltage transmission disconnect switch at the entrance to the substation. This is the defining line applied in Canadian OATTs (except Hydro Quebec).

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[16] Transmission is defined by law in Quebec to be "*a network of installations for the transmission of electric power, including step-up transformers located at production sites, transmission lines at voltages of 44 kV or higher, transmission and transformation substations and any other connecting installation between production sites and the distribution system.*"

[17] **MECL Transmission Tariff Rates Design** report (Attachment E), Nov 30, 2006, page 13

[18] MECL only includes indirect OM&A costs in its Schedule 9 and bills direct OM&A for each GRTA facility directly to the appropriately generation owner. This is different than the NB Power and FERC *Pro Forma* OATTs which include total OM&A (direct plus indirect costs) in schedule 9. This is a minor deviation from FERC and is believed by WKM to be superior to the *Pro Forma* because it avoids the possibility of over or under charging for OM&A for GRTA facilities.

[19] Note Table 2 of the MECL Evidence document where "MECL contracted Wind related revenue requirement" is not included in the "OATT related revenue requirement".

Some parties have argued that radial lines to local load should be allocated to distribution but FERC has not mandated a specific allocation. ISO-NE has a two tiered transmission OATT structure where there is a pool wide tariff for pool transmission facilities ("PTF Tariff") and local tariffs for each separate transmission owner's system. This originated not as intent to allocate costs to distribution but as a negotiated settlement between transmission owners to get to a PTF Tariff.

In Canada most OATTs do not assign costs of radial lines to distribution. They are generally included with all interconnected lines so that all end use customers within a jurisdiction would have the same transmission component cost recovered through their rates. It is in line with the public policy objective that all citizens (and ratepayers) be treated equally.

In the current MECL interim OATT there is an anomaly in this regard concerning the *"Summerside Related Assets* [which] *are those parts of the transmission system which are owned by MECL and used only to serve the City of Summerside"*.[20] The radial lines to all MECL substations are not charged to distribution but the 69 kV line T11 from the Sherbrooke terminal station to Summerside is charged to Summerside Electric. It is the opinion of WKM that this is incorrect and it is proposed that in the upgraded OATT that this charge be reversed and retained as a contribution to the Revenue Requirement for Transmission Services. Review of the MECL evidence confirms that this change has been made.

System Operations Function – In FERC Order 888 all costs related to system operations including the system control center, SCADA equipment and communications costs should be allocated to the ancillary service **Scheduling, System Control and Dispatch Service** that is specified in Schedule 1 of the OATT. This has been done in the MECL interim OATT and is proposed for the upgraded OATT.

Transmission Service Function – The costs remaining from the total transmission system revenue requirement after the previous three allocations have been removed would be the costs allocated for transmission service. Other than the generator connection lines this would be the costs for all transmission lines at a voltage of 69 kV and higher plus all terminal stations in the system plus the interconnection costs to NB Power. The interconnection costs would include lease payments to the Province of PEI for the cables between Bedeque and Murray Corner, OM&A costs for the cables, and any direct assignment costs that MECL has incurred related to transmission facilities in New Brunswick that were undertaken to improve the interconnection capability with NB Power.

[20] MECL Transmission Tariff Rates Design report (Attachment E), Nov 30, 2006, page 14

Before we consider how rates are designed we need to do an allocation of the transmission services costs between the two types of transmission service defined in the FERC *Pro Forma* OATT - Network Service and Point-to-Point Service. For this FERC has provided direction in Order 888 that costs are to be allocated based on the relative contribution to the transmission system peak load. Long Term (one year or more) Firm Point-to-Point Service should be based on the MWs of service reserved and Network Service should be based on "*a twelve monthly coincident peak (12 CP) allocation method.*"[21] But this allocation is only for Network and Long Term Firm Point-to-Point services. Before the allocation is done a projection of the expected revenue from shorter term Point-to-Point reservations is subtracted or alternatively converted to equivalent Long Term Firm Point-to-Point service.

3. Rate Design

In the Order 888 *Pro Forma* FERC has applied the "Postage stamp" rate approach for both Network service and Long Term Point-to-Point service. It has been accepted and applied by the vast majority of American and Canadian utilities but it is not mandatory. FERC would consider other rate designs on a case by case basis.

An example is the Maine Electric Power Company ("MEPCO") distanced based rate for service from the New Brunswick border through Maine to the Orrington , Augusta and Maine Yankee terminal stations in Maine. It was in place from 1996 until 2007 when the MEPCO revenue requirement was rolled into the ISO-NE PTF Tariff along with the Maine portion of the new 345 KV line from Point Lepreau to Orrington.

Another approach discussed in Order 888 is flow-based pricing which is the method applied in the ISO-NE market. Within ISO-NE there are no Firm Point-to-Point tariffs, only a Network tariff to serve loads. In place of internal Point-to-Point service there are financial transmission rights that are auctioned to generators. The market is settled with generators based on locational marginal prices ("LMP") at the injection node of the generator. To guarantee delivery at a price from node A where a generator is located to node B where its load customer is located the generator would purchase the financial transmission rights from A to B. If there is no congestion between A and B the generator is able to physically deliver its electricity to the customer at its contracted price. If there is congestion between A and B the LMP at B will be higher than at A. The generator through its financial rights will get paid the LMP differential between A and B. This will enable it to purchase the higher priced energy on the B side of the constraint and deliver it to its customer at the same price it would have received at node A. While settlement with generators is at the LMP of its connection node, settlement with loads is on a zonal basis where Maine for example is a zone. This market system is employed in order to

[21] FERC Order 888, page 296

economically dispatch hundreds of generators at least cost to supply a peak load of about 30,000 MW.

The FERC position on flow-based pricing in Order 888 is summarized as follows:

> *"We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. ... We welcome new and innovative proposals, but we will not impose them in this Rule. … We wish to emphasize further that in taking this approach we are not endorsing the traditional contract path approach as the only available approach. We continue to approve contract path pricing because it is the long-established pricing method. ... We also believe the adoption of flow-based pricing will be more practical on a regional, instead of individual utility, basis".*[22]

WKM agrees with FERC in this regard. While LMP flow-based pricing works in a large regional market like ISO-NE, each load zone is at least an order of magnitude larger than PEI. Use of such a method for a system as small as MECL's system would not be efficient or economic. New Brunswick, which is electrically twelve (12) times the size of PEI attempted to implement a simpler market than ISO-NE using a simpler postage stamp rate and was not successful. The most efficient approach for MECL is to implement the postage stamp rate design as set out in the FERC Order 888 *Pro Forma* OATT in the same manner as has been done by NB Power, NSPI and other Canadian utilities. The rates would be determined as detailed here:

> The **Network Service** rate in $/MW-month is equal to one twelfth of a numerator equal to the Network Revenue Requirement in dollars($) divided by a denominator equal to the 12CP Network load in MW.

> The **Long Term Point-to-Point** rate in $/MW-month is equal to one twelfth of a numerator equal to the Long Term Firm Revenue Requirement in dollars($) divided by a denominator equal to the amount of Long Term Firm Point-to-Point service in MW.

It should be noted that because the allocation of revenue requirement between Network Service and Long Term Point-to-Point Service is the same as the billing determinant denominator (i.e., 12 CP load for Network and reservation capacity for Point-to-Point), the resulting rates are equal on a monthly basis for the two services. Because of this it is not necessary to do a separate allocation of revenue requirement to each of Network and Point-to-Point Services.

An alternative rate determination approach for Long Term Firm Point-to-Point is not to subtract the revenue projection of short term point-to-point sales prior to the allocation

[22] FERC Order 888, pages 96-98

to each of Network and Point-to-Point Service but determine for the short term reservations an equivalent long term reservation in MW and add it to the denominator along with Network usage and Long Term reservation capacity. This alternative approach will yield the same monthly rates for both Network and Point-to-Point Service as the method at lines 18-24 above. It was the approach applied by MECL in the interim OATT and is the method applied again in the proposed upgraded OATT.

Point-to-Point service is available as Firm and Non-Firm for shorter periods than Long Term Firm. The Appalachian pricing method approved by FERC sets monthly rate = the annual rate/12, weekly rate = annual rate/52, daily rate = weekly rate/5, on-peak hourly rate = daily rate/16 and off-peak hourly rate = annual rate/8760.

Review of the **MECL Transmission Tariff Rates Design** report confirms that the current MECL interim OATT is 100% compatible with FERC for Scheduling, System Control and Dispatch Service (Schedule 1) and Point-to-Point Service (Schedules 7 and 8) in applying the postage stamp rate approach and the Appalachian pricing for shorter terms. It is also the same method applied by NB Power and NSPI and is proposed to continue in the MECL updated OATT.

Network Service in the MECL interim OATT is compatible with FERC Order 888 but there has been a minor adjustment to Network Service rates in Order 890. Rather than set a fixed monthly rate for Network Service in Attachment H of the OATT by using a projected or historic 12CP value, Order 890 sets a Network Customer's rate as *"a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's Annual* [Network Service] *Transmission Revenue Requirement."*[23] The effect of this change is that the Transmission Provider would be guaranteed to collect the same amount each month. This presumably would make budgeting a little easier for the Transmission Provider and Transmission Customers but NB Power has not adopted this change in its OATT. It has continued the use of a $/MW-month rate which has been accepted by the NB EUB. MECL, similar to NB Power, does not propose the change either because using a fixed rate would more closely match revenues with increasing costs as load grows. It is also administratively preferable as it avoids the need for detailed cost allocation updates each year. This is a minor deviation from Order 890 but is believed to be more appropriate for PEI.

4. Generation Related Ancillary Services

The ancillary services below are required in order to operate the power system in a reliable manner;

- Schedule 2 - Reactive Supply and Voltage Control

[23] FERC Order 890 Pro Forma OATT, Section 34.1

- Schedule 3 - Regulation and Frequency Response
    - (a) Regulation (Automatic Generation Control),
    - (b) Load Following,
    - (c) AGC and Load Following for Non-Dispatchable Wind Generation
- Schedule 5 - Operating Reserve – Spinning,
- Schedule 6 - Operating Reserve – Supplemental
    - (a) Supplemental (10-minute);
    - (b) Supplemental (30-minute)

While these ancillary services may be able to be provided by demand response or other equipment all are predominantly provided by the flexible operation of generators. This is certainly the situation in the New Brunswick Balancing Area which includes PEI. Determination of the actual costs (revenue requirement) to provide these services is difficult and crosses over into the competitive world of generation related costs.

An alternative costing approach is to use as a proxy the long run marginal costs of the types of generators and transmission equipment that can provide the services. This approach was taken by NB Power in its recent OATT application as summarized in the Table III-1 below:

Table III-1

Proxy Unit Costs

Schedule	Ancillary Service	Proxy Source	Rate ($/unit -yr)	
2	Reactive Supply & Voltage Control	Static VAR Compensator	$ 5.98	/kVAR-yr
3(a)	Regulation (AGC)	Combined Cycle (Fast AGC)	$ 99.86	/kW-yr
3(b)	Load Following	Combined Cycle (Slow AGC)	$ 99.45	/kW-yr
5	Operating Reserve – Spinning	Combined Cycle	$ 99.31	/kW-yr
6(a)	Supplemental Reserve - 10 minute	Combustion Turbine (Quickstart)	$ 64.60	/kW-yr
6(b)	Supplemental Reserve - 30 minute	Combustion Turbine	$ 64.60	/kW-yr

WKM supported the use of these proxy costs in evidence and in response to the information request WKM(NBEUB) IR-2 which is provided as Attachment C. The NB EUB accepted WKM's argument and approved the use of proxy costs for the OATT of NB Power. These same proxy costs are appropriate for MECL because MECL relies on NB Power for Schedules 3 and 5. It is not capable of providing the services from its generators because MECL generating units are not synchronized continuously as required. Rather, MECL purchases the Schedule 3 and 5 services from NB Power and passes the costs through to Transmission Customers requiring them. MECL self-supplies its Schedule 6 obligation and it is logical that its provision through the OATT be equal to the NB Power rates for the same service. It is proposed that, rather than specify rates in the MECL OATT for Schedules 3, 5 and 6, referral be made to the NB Power OATT and have its rates apply.

Rates for Schedule 2, which is a compulsory service, are determined in the same manner as rates for transmission service, that is, the rate in $/MW-yr equals the revenue requirement for the service (MVAR requirement times proxy MVAR cost) in dollars ($) divided by the amount of transmission service in MW. It will not be equal to the NB Power rate because the MVAR requirement for PEI is different than that in New Brunswick relative to transmission usage. WKM has reviewed the determination of the proposed Schedule 2 rate in the MECL evidence and agrees with it.

Rates for Schedules 3, 5 and 6, which are often referred to as capacity based ancillary services (CBAS), are not based on MW of transmission service but on MW of obligation of the purchasing party. The obligation is equal to the 12CP load ratio share of each party within the NB Balancing Area. Table III-2 indicates the allocation of obligations within the area.

Table III-2
CBAS MW Obligations

		NB Balancing	Obligations		
		Area Requirement	NB	NMe	PEI
	Peak Load (using 2013/14 12 CP)	2452	2149	107	196
	Percentage Share	100%	88%	4%	8%
Schedule					
3(a)	Regulation	19.0	16.7	0.8	1.5
3(b)	Load Following	53.0	46.6	2.3	4.2
5	Spinning Reserve	87.5	76.7	3.8	7.0
6(a)	Supplemental (10 Minute)	219.5	192.4	9.6	17.5
6(b)	Supplemental (30 Minute)	183.0	160.4	8.0	14.6

Within PEI the obligation is also shared based on the 12 CP load ratio share. For example, if Summerside Electric has a 10% load ratio share it is obligated to provide 10% of the PEI obligation and MECL would be obligated to provide 90%. Summerside Electric has the option to self supply its 10% obligation, to purchase it from a third party (most likely NB Power), or to purchase it via the MECL OATT which would be at the NB Power rate.

IV GENERAL TERMS AND CONDITIONS OF THE OATT

The terms and conditions of FERC compatible open transmission access are specified in the text of the *Pro Forma* OATT. This Chapter will begin by identifying all the FERC orders and rulings that have occurred since 2002 that have modified the *Pro Forma* OATT and then discuss how they should be addressed in the MECL OATT. In addition other modifications that are appropriate for PEI and are consistent with or superior to the FERC standards will be considered.

1. FERC Orders Since 2002 Other than Order 890

In addition to FERC Order 890, which includes several modifications to the *Pro Forma* OATT, there are also terms and conditions adjustments included in Orders 2003, 2006, 661, 676, 698, 717, 739, 764, 784, 792 and 1000. Each of these will be reviewed first prior to tackling Order 890 changes, except that Order 717 is considered in Chapter VI - STANDARDS OF CONDUCT and more detail regarding Orders 676 and 698 are included in Chapter VII – OPEN ACCESS SAMETIME INFORMATION SYSTEM.

Orders 676 and 698 – These 2006 and 2007 FERC orders adopted, by reference as part of the *Pro Forma*, a number of standards that had been developed by the North American Energy Standards Board ("NAESB") in accordance with NAESB's inclusive and formal standards development process. These allowed FERC to adopt more specific requirements for open access transmission, including Open Access Same-Time Information Systems ("OASIS") and coordination between natural gas and electric system operations. Changes to Section 4 of the *Pro Forma* were made to reference NAESB and require posting of the process by which the Transmission Provider shall add, delete or otherwise modify the rules, standards and practices that are not included in the OATT. More detail is provided in Chapter VII concerning OASIS.

Order 739 - FERC issued this order in 2010 to promote a competitive market for capacity reassignment and transfers. It removed the cap on the pricing of transmission re-sales and assignments that had previously existed by modifying the wording of Section 23.1 of the *Pro Forma* OATT as follows:

> *"Compensation to Resellers shall ~~not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmitter's cost of expansion~~ be at rates established by agreement between the Reseller and the Assignee*."

These changes along with some minor modifications to Sections 23.2 and 23.3 and acknowledgement in Schedules 7 and 8 that *"the rates and rules governing charges and* *discounts"* in those schedules "*shall not apply to resales of transmission service"* are proposed to be added to the MECL OATT.

Order 764 - This order was issued by FERC in 2012 to facilitate the addition of variable energy resources such as wind and solar generation to the grid. This order called for the introduction of intra-hour scheduling, data reporting to support variable energy resources power production forecasting, and a regulation service that could be used to recover costs incurred to regulate variable energy resources. This order contained the following specific revisions in the *Pro Forma* OATT to Sections 13.8 and 14.6 and they are also proposed for the MECL OATT:

> "Hour-to-hour *and intra-hour (four intervals consisting of fifteen minute schedules)* schedules …
> … the next *scheduling interval* ~~clock hour~~ provided …
> … hour-to-hour *and intra-hour* schedules … "

Intra-hour schedules would be beneficial for the balancing of wind generation on the Island both for local load supply and for exports to and through New Brunswick to ISO-NE. Implementation of intra-hour schedules must be coordinated with NB Power which is expected to take about six (6) months following their approval.

Order 784 – This order was issued in 2013 regarding market based pricing for third party provision of Ancillary Services. The order recognized that resources supplying Regulation Reserves have different speeds and accuracy and these relative capabilities should be considered. This order arose, in part, from the introduction of technologies that could inherently provide faster and more accurate services. The order added the following wording to Schedule 3 of FERC's *Pro Forma* OATT and they are also proposed for the MECL OATT.

> *"The Transmission Provider 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."*

Orders 2003, 2006, 661 and 792 – These FERC Orders deal with the terms of generator interconnection agreements and require that a Standard Small Generator Interconnection Agreement be included in the OATT for generators that are 20 MW or less. NB Power does not have a Standard Small Generator Interconnection Agreement in its OATT and its omission was raised as a potential FERC non compliance issue in the recent NB Power OATT hearing.

> *"Attachment J of the Proposed OATT is a standard form Generation Connection Agreement. Ms. Marlette* [NB Power expert witness] *acknowledges that this deviates from the Pro Forma OATT, in that it does not contain a separate Standard Small Generator Interconnection Agreement (applicable to a generator of 20 MW or less). Attachment J applies the same terms to both large and small generators. This deviation, in Ms. Marlette's view, is mitigated by the fact that FERC accepted the NBSO transmission tariff in 2011, under the same conditions"*[24]

NB Power argued that because of the successful past use of its interconnection agreement, the relatively low volume of anticipated requests for connections of generators, and FERC's prior review of the same provisions in the NBSO OATT there was no need to replace or update its current agreement. WKM agreed with NB Power's position and so did the EUB except that it required NB Power *"to submit a report by December 31, 2015, which assesses the potential need for a separate small generator connection agreement to be part of the transmission tariff, and outlining any issues with respect to its adoption"*.[25] The report has been submitted but there has been no response from the EUB.

The Generation Connection Agreement of MECL in Attachment J of its interim OATT is similar to that of NB Power and includes everything necessary for connection of a thermal generator. To make reasonable provision for wind generators MECL has since developed a Schedule K for its Generator Connection Agreement that eliminates portions of the agreement meant for thermal generators and adds the specific issues needed for wind generators. While not being a Standard Small Generation Connection Agreement as required by FERC it does include much simplification for wind generators, large and small. Given that wind generators are the most likely type of small generators that are expected on PEI the Schedule K to Attachment J in the proposed upgraded OATT is a reasonable substitute for a Standard Small Generation Connection Agreement. It achieves much of the FERC requirement and is appropriate for PEI.

Order 1000 - In 2011 FERC issued Order 1000 implementing reforms for regional transmission system planning and cost allocation.

"The rule establishes three requirements for transmission planning:

[24] Decision – Matter 256, NBEUB, May 13, 2015, Paragraph 36, Page 8 available at http://www.nbeub.ca/opt/M/browserecord.php?-action=browse&-recid=441

[25] Ibid, Paragraph 40, Pages 8-9

- *Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.*
- *Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.*
- *Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs."*[26]

"The rule establishes three requirements for transmission cost allocation:

- *Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles.*
- *Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles.*
- *Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method."*[27]

MECL participates in the Maine and Atlantic Technical Planning Committee ("MATPC") which attempts to coordinate regional planning on a voluntary basis but there is no agreed cost allocation method. The MECL transmission system is a radial connection to NB Power such that any commitment by MECL to a regional planning process with regional cost allocation methods is dependent on NB Power and its coordination of regional activities. But NB Power is not prepared to take on such responsibilities as stated in its OATT filing.

> *"NB Power cannot operate in an autonomous or unilateral fashion in the areas of regional and inter-regional transmission planning. Rather, NB Power must operate within a framework of provincial control over electricity*

[26] FERC Order 1000 Fact Sheet, July 21, 2011

[27] Ibid

> *policy. This provincial framework does not currently encompass a formal, regulator approved process for regional or inter-regional transmission planning or regulation. Any utility-driven creation of such a framework would require voluntary multilateral utility agreements that do not exist, and would not likely exist without government approval. This situation makes it infeasible for NB Power to adopt the regional and interregional aspects of Order No. 1000 in its OATT, and thus these provisions are not included in the NB Power OATT*."[28]

As a result, other than adding wording to Attachment K Transmission System Planning, as NB Power has done, to address Order 1000's call for an OATT to describe how public policy requirements are to be taken into consideration in the local transmission planning process, MECL is not able to adopt the regional and interregional aspects of Order 1000 in its OATT.

2. FERC Order 890 OATT Changes

This order, entitled *Preventing Undue Discrimination and Preference in Transmission Service*, issued in 2007 and its later rehearing order, Order 890-A *"reforms the open access regulatory framework first set out in Order Nos. 888 and 889 in 1996. The rule ensures that transmission service is provided on a non-discriminatory, just and reasonable basis and helps provide the foundation for a competitive electric power market. Order No. 890 also provides for more effective regulation and transparency in the operation of the transmission grid."*[29]

"The reforms that FERC affirmed in Order No. 890 are designed to: (1) strengthen the Pro Forma open access transmission tariff (OATT) to ensure that it achieves its original purpose of remedying undue discrimination; (2) provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement; and (3) increase transparency in the rules applicable to planning and use of the transmission system."[30]

The reforms to the *Pro Forma* OATT as a result of FERC Order 890 (including the rehearing Orders 890A, 890B, 890C and 890D) are:

- Increased transparency in Available Transfer Capability ("ATC") determination;

[28] NB Power OATT filing, Document 2.03 Part A Terms and Conditions, page 24, lines 1-10
[29] FERC News Release, June 19, 2008
[30] Ibid

- "Conditional firm" component for Long-Term Point-to-Point Transmission Service;
- Initial Allocation and Extension Procedures;
- Extension of Reciprocity;
- Removal of penalties on Point-to-Point reservation exceedances
- Designation of Network Resources;
- Reservation Priority and Pre-Confirmed transmission requests
- Failure to meet study deadlines;
- Processing of Service Requests and Transfers;
- Creditworthiness;
- Clarification of tariff ambiguities and additional definitions;
- Open, coordinated and transparent transmission planning; and
- Energy and generator imbalance penalties.

The first nine of these reforms are included in the following sub sections while *"open, coordinated and transparent transmission Planning*" and "*energy and generator imbalance penalties*" require more extensive discussion so they are addressed through separate sections.

Available Transfer Capability – The changes proposed by MECL are intended to make the ATC calculations more transparent while ensuring that they respect FERC Order 890 and North American Electric Reliability Corporation ("NERC") reliability standards. NB Power modified Attachment C of the NB Power OATT (Methodology to Assess Available Transfer Capability) in order to address FERC Order 890 compatibility and to update the ATC calculation methodology to reflect current industry practices. FERC Order 890 requires that detailed information about the inputs to the calculations be specified. Current industry practices apply different terminology than the MECL OATT currently uses.

ATC is the transfer capability on a Transmission Provider's transmission system that is not already committed and is therefore available for commercial use. The methodology proposed by MECL is the same as that used by NB Power, with whom MECL must coordinate its TTC and ATC values. The proposed methodology is provided in Attachment C – Methodology to Assess Available Transfer Capability in the MECL Redline OATT and WKM supports its approval by IRAC.

Conditional Firm Point-to-Point Service – The obligation of the Transmission Provider in Section 15.4 to expand or modify its transmission system in order to provide Firm Point-to-Point Service has to now include provision of service through re-dispatch or conditional curtailment.

The conditional service is provided "*with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s)"*.[31] For re-dispatch *"the Transmission Provider will use due diligence to provide re-dispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the re-dispatch, or (iii) the Transmission Customer terminates the service because of re-dispatch changes resulting from the reassessment*."[32] A biennial assessment is also done for the conditional service.

There is also a requirement in Section 13.4 where *"The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Transmission Provider shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, the Transmission Provider shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur"*.[33]

Section 19.3 System Impact Study Procedures has been expanded and clarifies how "*re-dispatch*" and "*conditional curtailments*" are to be considered. These proposed changes plus some additional wording in Sections 13.5, 13.6 and 14.7 are provided in the MECL Redlined OATT.

Initial Allocation and Extension Procedures – The current interim OATT of MECL utilizes the wording of the NB Power 2003 OATT in Section 2.1 Initial Allocation which is different than the FERC *Pro Forma* OATT. NB Power has retained the use of an open season for new transmission capability in its proposed OATT. It is appropriate for NB Power because of congested interconnections from Quebec and to New England and it has been accepted by the NB EUB. However, it is not appropriate for MECL where its interconnection capability from PEI to New Brunswick is not congested and there is surplus ATC today that is not contracted. WKM recommends that there is no need for Section 2.1 in the MECL OATT and that it be revoked. This has been done by other Canadian utilities in their OATT updates and is more compatible with FERC Policy than the NB Power approach.

[31] FERC Order 890 *Pro Forma* OATT, Section 15.4(c)
[32] Ibid, Section 15.4(b)
[33] Ibid, Section 13.4

The term for Long Term Firm Point-to-Point Transmission Service to have extension rights in Section 2.2 has been increased from one (1) year to *five (5)* years. The extension has to match any competing request and be for a term of at least five (5) years. The existing firm service customer "*must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement"*.[34] The FERC Order 890 wording is proposed as provided in the MECL Redline OATT.

Extension of Reciprocity – Reciprocity must be extended to all members of a power pool such as ISO-NE if the Transmission Provider or an affiliate takes service on the power pool system. The following FERC wording has been added to Section 6 of the proposed MECL OATT:

> *"A Transmission Customer that is a member of, or takes transmission service from, a power pool, Regional Transmission Group, Independent System Operator, or other transmission organization also agrees to provide comparable transmission service to the transmission-owning members of such power pool, Regional Transmission Group, Independent System Operator, or other transmission organization, on similar terms and conditions over facilities used for the transmission of electric energy in interstate or interprovincial commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy in interstate or interprovincial commerce owned, controlled or operated by the Transmission Customer's corporate Affiliates".*[35]

Removal of penalties on Point-to-Point reservation exceedances – In the Order 888 *Pro Forma* OATT Sections 13.9 (for Firm) and 14.8 (for non-Firm) specify the rate treatment if a Transmission Customer exceeds its reserved capacity.

> *"The transmission Customer shall pay 110% of the charge for hourly On-Peak or Off-Peak Point-to-Point Transmission Service based on the time of the excess, including Schedules 1 and 2 Ancillary Services. During periods when the Transmission System is constrained, the Transmission Customer shall pay 150% of the charges …"*

In the Order 890 *Pro Forma* OATT Sections 13.9 and 14.8 are removed yet the Transmission Provider is required in Sections 13.7 and 14.5 to "*specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its reserved capacity at any Point of Receipt or Point of Delivery."* The

[34] Ibid, Section 2.2
[35] Ibid, Section 6

simplest way for MECL to "*specify the rate treatment*" for an exceedance is to retain Sections 13.9 and 14.8 in the proposed OATT. WKM believes that the penalties are reasonable.

Designation of Network Resources – There are changes in the *Pro Forma* OATT relating to specification and termination of Network Resources. These will clarify a Network Customer's requirements for the designation and termination of Network Resources to the benefit of both the Transmission Provider and the Network Customer. Under Order 890 the designation and termination are to be conducted via the Transmission Providers OASIS. NB Power has not made this change in its OATT because there are few Network Resource changes and modifying its OASIS would be costly. Currently any Network Resource changes are made via email and posted by NB Power TSO. MECL have a similar process that is adequate and need not be altered. WKM recommends that the wording changes be made to the MECL OATT as provided in the Redlined OATT (Sections 30.2, 30.3 and 30.9) but that the OASIS changes not be required.

Reservation Priority and Pre-Confirmed Requests - This proposed change introduces "Pre-Confirmed" requests for transmission service as a process for clarifying reservation priorities and to make requests for service more efficient. The typical request for transmission service is a three-step process whereby the Transmission Customer requests service, the Transmission Provider evaluates the request, and advises the Transmission Customer that the request can be met (if this is the case), and the Transmission Customer decides to proceed or not. A Pre-Confirmed request, as now proposed, would eliminate the final step. This means that the Transmission Customer and the Transmission Provider would both have the knowledge that the service would be taken if it is determined to be available.

In the case of Non-Firm Service, pre-confirmation can be a tie-breaker in the application of priority rights for competing Non-Firm Service requests. In the case of Firm Service requests, it provides an up-front commitment to purchase the service if it is available and thus provides greater certainty for both the Transmission Provider and the Transmission Customer. This proposed change affects Sections 13.2, 14.2, 17.2 and 18.2 as is provided in the MECL Redlined OATT.

Failure to Meet Study Deadlines - The MECL OATT currently states that the Transmission Provider will use due diligence to have System Impact Studies and Facilities Studies completed within 60 days following execution of an appropriate study agreement. FERC Order 890 adds a new Section 19.9 that specifies performance limits beyond which there are consequences for the Transmission Provider. Such consequences include the need to notify the regulator with explanation of any extenuating circumstances and for persistent failures monetary sanctions.

Similar to NB Power WKM recommends that notifications to IRAC be required but that monetary sanctions not be. The proposed change requires that IRAC be notified when more than 20 per cent of these studies are not completed within the completion deadline period for two consecutive quarters. The proposed changes are in Sections 19.9 and 32.5 of the MECL Redlined OATT.

Processing of Service Requests and Transfers – Order 890 altered the forms used to request service in Attachments A and B of the *Pro Forma* OATT. Form A now includes both Long Term and Short Term Firm Point-to-Point requests while Form B is only for Non-Firm requests. Also a new form Attachment A-1 is added to document **"***The Resale, Reassignment Or Transfer Of Point-To-Point Transmission Service*." In addition there are minor wording changes in Sections 14.4, 17.1, 18.1 and 23.1. All of the proposed changes are provided in the MECL Redlined OATT.

Creditworthiness - Although the creditworthiness of customers is a concern for all utilities, it is particularly important in an OATT context because a lack of clarity could interfere with the principles of open access.

In accordance with FERC Order 890, MECL proposes to remove the existing details from Section 11 of the MECL OATT and create a new Attachment O - Creditworthiness Procedures. Attachment O outlines information that the Transmission Provider requires to assess a Transmission Customer's ability to meet its payment obligations under the MECL OATT.

Clarification of tariff ambiguities and additional definitions – There are wording changes in the Pro Forma for clarity plus additional definitions. The major wording change is to alter *"transmission capacity"* throughout the document to *"transfer capability"* which is industry standard usage. Treatment of discounts for Point-to-Point service has been clarified in both Schedules 7 and 8. New definitions have been added for Affiliate, Pre-Confirmed Application, Monthly Demand, Non-Firm Sale, Regional Transmission Group and System Condition. In addition definitions for Good Utility Practice, Network Resource and Load Ratio Share have been expanded or clarified.

In addition to FERC Order 890 clarifications there are clarifications made to reflect altered conditions in PEI and the Maritimes Area. Business Day has been simplified by removing reference to specific times of day. The Control Area Operator has been changed from NBSO to NB Power TSO to recognize the current situation. Membership of the Transmission System Users Group in Section 12.7 has been expanded to achieve greater openness for Transmission Planning under Attachment K. The proposed wording for each of these proposed changes is included in the MECL Redlined OATT.

3. <u>An Open, Coordinated and Transparent Planning Process</u>

A major requirement under FERC Order 890 is for the Transmission Provider to establish a coordinated, open and transparent transmission planning process with participation by its transmission customers, neighbouring systems, regulators and other stakeholders.

The planning process requirement applies to all jurisdictional Transmission Providers, all transmission owning members of ISOs and RTOs and, through the retention of the reciprocity language in the Order 888 *Pro Forma* OATT, also applies to non-jurisdictional transmission providers (including those located in foreign countries) that take advantage of open access due to improved planning.

In Order 888 FERC set certain minimum requirements for transmission system planning. In Order 888-A FERC encouraged utilities to engage in joint planning with other utilities and customers. They also required that new facilities be constructed to meet the service requests of long-term firm point-to-point customers and that Good Utility Practice be applied to determine the need for and design of new facilities. However, specific requirements for coordination with customers and neighbours were not included. FERC expressed concern that "t*aken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no means to determine whether the plan developed by the transmission provider in isolation is unduly discriminatory*."[36]

To remedy this situation FERC issued Order 890 setting out the principles for a coordinated, open and transparent transmission planning process that needed to be detailed in an attachment to the Transmission Provider's OATT. Many details in Order 890 were challenged by interveners for rehearing and clarification. Subsequently, Order 890-A was issued and it re-iterated the need for the planning process, the requirement for an Attachment K to explain the process and the principles to be followed in a transmission planning process.

> *"The Commission affirms the decision in Order No. 890 to amend the Pro Forma OATT to require coordinated, open and transparent transmission planning on both a local and regional level. Although the Commission encouraged utilities to engage in joint planning in Order No. 888-A, it placed no affirmative obligation on transmission providers to coordinate with their customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans, nor were transmission providers required to coordinate planning activities with other transmission providers in their region. This lack of clear criteria regarding*

[36] FERC Order 890, Paragraph 425

> *planning obligations has created opportunities for undue discrimination by transmission monopolists with an incentive to deny transmission or offer transmission on an inferior basis."*[37]

FERC went further and *"identified nine planning principles in Order No. 890 that must be satisfied for a transmission provider's planning process to be considered compliant with that order. These nine planning principles are:*

> *(1) Coordination – the process for consulting with transmission customers and neighboring transmission providers;*
>
> *(2) Openness – planning meetings must be open to all affected parties;*
>
> *(3) Transparency – access must be provided to the methodology, criteria, and processes used to develop transmission plans;*
>
> *(4) Information Exchange – the obligations of and methods for customers to submit data to transmission providers must be described;*
>
> *(5) Comparability –transmission plans must meet the specific service requests of transmission customers and otherwise treat similarly-situated customers (e.g., network and retail native load) comparably in transmission system planning;*
>
> *(6) Dispute Resolution – an alternative dispute resolution process to address both procedural and substantive planning issues must be included;*
>
> *(7) Regional Participation – there must be a process for coordinating with interconnected systems;*
>
> *(8) Economic Planning Studies – study procedures must be provided for economic upgrades to address congestion or the integration of new resources, both locally and regionally; and*
>
> *(9) Cost Allocation – a process must be included for allocating costs of new facilities that do not fit under existing rate structures, such as regional projects."*[38]

It is also worth noting that meeting NERC planning standards is not necessarily sufficient to meet Order 890 requirements. In its White Paper FERC staff state:

> *"The Commission also made clear that reliance on existing NERC planning processes may not be sufficient to meet the requirements of Order No. 890 unless they are open and inclusive and address both reliability and economic considerations"*[39]

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[37] FERC Order 890A, Paragraph 171

[38] Ibid, Paragraph 181

[39] FERC Staff White Paper, "Order No. 890 Transmission Planning Process", August 2, 2007, page 13

NB Power in its recent revision of its OATT developed an extensive Attachment K document. After discovery it was found to deviate from FERC policy regarding generation interconnection to the transmission system and potential loss of queue position.

> *"Ms. Marlette's evidence indicated that FERC's open access transmission policy does not require a customer to apply for transmission service at the same time as it applies for [generation] interconnection service, and that these services are considered as separate. In her opinion, section 5.2.2 of Attachment K of the Proposed OATT may be construed as inconsistent with this approach".* [40]

> *"The NB Power OATT, unlike the Pro Forma OATT, does not provide for specifically identified circumstances under which a change can be made to an interconnection without losing queue status".*[41]

The NB EUB in its Decision directed NB Power to revise Attachment K to be *"consistent with the Pro Forma OATT, to de-link interconnection service from transmission service"*[42] and *"to adopt the Pro Forma OATT language regarding the loss of queue position without modification".*[43]

NB Power revised its Attachment K accordingly and it has been maintained in the May 2016 version of the NB OATT. WKM used the NB Power Attachment K as a starting point and made some minor edits to make it appropriate for MECL and PEI stakeholders. It is included as Attachment K in the Redlined OATT.

In addition to inclusion of Attachment K there are references throughout the OATT (Sections 15.4, 16.1, 17.2, 28.2, 29.2 and 31.6) for the Transmission Provider to act "*consistent with"* and for Transmission Customers to *"provide information required*" that meets "*the obligations in Attachment K."* These modifications are also included in the Redlined OATT.

4. Energy and Generator Imbalance Penalties

FERC's objective regarding imbalance pricing was to eliminate the variability and confusion that existed in the industry while maintaining an incentive for balanced schedules that would preserve reliable operation of the interconnected power systems in

[40] Decision – Matter 256, NBEUB, May 13, 2015, paragraph 41, Page 9 available at http://www.nbeub.ca/opt/M/browserecord.php?-action=browse&-recid=441

[41] Ibid, Paragraph 52, page 11

[42] Ibid, Paragraph 43, Page 9

[43] Ibid, Paragraph 55, Page 11

a fair and not unduly discriminatory manner. Note the following passages from Order 890.

> *"In the NOPR, the Commission noted that the existing energy imbalance charges described in Order No. 2003 are the subject of significant concern and confusion in the industry. The Commission expressed concern about the variety of different methodologies used for determining imbalance charges and whether the level of the charges provides the proper incentive to keep schedules accurate without being excessive. The Commission therefore proposed to modify the current Pro Forma OATT Schedule 4 treatment of energy imbalances and to adopt a separate Pro Forma OATT schedule for the treatment of generator imbalances.*
>
> *The Commission proposed to create new energy and generator imbalance schedules based on the following three principles: (1) the charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger; and (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as waiving the more punitive adders associated with higher deviations".*[44] (Underline added for emphasis)

Through Order 890 and its rehearing orders, a tiered approach to imbalance pricing based on the above three principles has been adopted by FERC for both Energy Imbalance (Schedule 4 in the *Pro Forma* OATT) and Generator Imbalance (a new Schedule 9 in the *Pro Forma* OATT).

> *"Specifically, imbalances of less than or equal to 1.5 percent of the scheduled energy (or two megawatts, whichever is larger) will be netted on a monthly basis and settled financially at 100 percent of incremental or decremental cost at the end of each month. Imbalances between 1.5 and 7.5 percent of the scheduled amounts (or two to ten megawatts, whichever is larger) will be settled financially at 90 percent of the transmission provider's system decremental cost for overscheduling imbalances that require the transmission provider to decrease generation or 110 percent of the incremental cost for underscheduling imbalances that require increased generation in the control area. Imbalances greater than 7.5 percent of the scheduled amounts (or 10 megawatts, whichever is larger) will be settled at*

[44] FERC Order 890, Paragraphs 634 and 635

75 percent of the system decremental cost for overscheduling imbalances or 125 percent of the incremental cost for underscheduling imbalances"[45]

This three tiered approach is based on incremental costs and provides incentives for accurate scheduling. To account for the special circumstances of intermittent generators such as wind and solar, they are exempted from penalties in the third band. The following text is added to Schedule 9:

> *"an intermittent resource will be exempt from this deviation band* [#3] *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."*[46]

Regarding the definition of "*incremental and decremental costs*" the final ruling of FERC is that energy imbalance pricing for both load and generator imbalances is to be based on the "*incremental cost of the last 10 MW dispatched for any purpose, e.g., to serve native load, correct imbalances, or to make off system sales.*" Furthermore, there is to be no distinction between incremental and decremental costs. As stated in the *Pro Forma* schedules for both energy and generator imbalances

> *"For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, e.g., to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and re-dispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable".*[47]

To apply the imbalance pricing policies of FERC Order 890 to the MECL OATT there are a few issues that need to be clarified.

- Firstly, MECL do not require a separate schedule for Generator Imbalance as is done in the Order 890 *Pro Forma.* All three Maritimes Area utilities (NB Power, NSPI and MECL) currently utilize Schedule 4 Energy Imbalance to settle the imbalances of both loads and generators. It has been working effectively so this should continue.

[45] Ibid, Paragraph 664
[46] Order 890 *Pro Forma* OATT, Schedule 9
[47] Order 890 *Pro Forma* OATT, Schedule 4

- For MECL the incremental/decremental cost is dependent on the state of the transmission interface between PEI and New Brunswick. If the interface is not congested balancing is provided by the Control Area Operator (NB Power TSO) at its marginal cost which is the balancing charge under the NB OATT. If the interface is congested (i.e., scheduled at its maximum of 200 MW or curtailed to a firm schedule of 130 MW (winter) or 150 MW (summer)) then MECL provides the balancing from its marginally dispatched generation unit. Wording has been added to Schedule 4 to capture this reality.

- NB Power does not utilize the tiered three band penalty structure. This is because the Final Hourly Marginal Cost ("FMHC") was utilized to settle the NB Market by NBSO and a single imbalance price is necessary at the Northern Maine interface with New Brunswick in order for the Northern Maine Market to be settled. Unfortunately, it does not provide the incentives desired for accurate scheduling and this may change in the future.[48] An NB Power analysis of the penalty revenue that it would have received indicated a value of $5.6 million for the five year period up to 2015 with the last year being $1.4 million. Considering that the total NB Power Transmission revenue requirement is about $100 million this is not an insignificant amount. There has been no action by the EUB at this time but it surely will be considered when NB Power must update its revenue requirement in the next two years.

- The current reality for PEI is that there is actually an incentive to under schedule when the interconnection from New Brunswick is not constrained because the rate for energy imbalance is usually lower than the contract price of energy. And accurate scheduling is an issue for MECL when the NB transmission interface is constrained because it has to be done with On-Island generation resources. The tiered band structure is proposed as it is FERC compliant and should encourage more accurate schedules for MECL.

- There is a lot of wind generation on PEI that needs consideration so the penalty structure should not include band 3. Wind generators are proposed to be exempt from band 3 penalties.

The proposed Schedule 4 – Energy Imbalance for the MECL OATT includes the three tiered penalty band structure of FERC Order 890 and the exemption from Band 3 for intermittent generators. The proposed wording changes to Schedule 4 are provided in the Redlined OATT.

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[48] In the Decision on the NB OATT the EUB has directed NB Power to "*submit an analysis in relation to Schedule 4 of the transmission tariff to the Board by December 31, 2015*". The analysis *"is necessary to resolve whether the proposed Schedule 4 should be revised in the future."*

V REAL POWER LOSS, SYSTEM COSTS/CREDITS AND DISCOUNTS

Treatment of losses, credits and discounts is not done through a specific service in an OATT but for non-discriminatory transmission access it is important that the methods of their treatment be transparent and apply equally to all Transmission Customers. This chapter considers policies of FERC in this regard especially through Orders 888 and 890 and reviews treatments in the current MECL interim OATT and possible changes for the proposed updated OATT.

1. Real Power Loss

When electricity is injected into the transmission system by a generator at a Point of Receipt there are losses in the transmission lines and power transformers before it gets to the load at its Point of Delivery which FERC defines as Real Power Loss. In the Notice Of Proposed Rulemaking ("NOPR") leading to Order 888, FERC originally proposed that losses be handled as an ancillary service that would be provided by the Transmission Provider. After receiving several comments on the NOPR, FERC backed away from this position and set out the obligations of both the Transmission Customer and the Transmission Provider.

> *"Although proposed as an ancillary service in the NOPR, we will not require that Real Power Loss be included as an ancillary service in an open access transmission tariff. .... A customer seeking transmission service must bring to the transaction sufficient energy and capacity to replace the losses associated with its intended transaction. Consequently, we will require that the transmission customer's service agreement with the transmission provider identify the party responsible for supplying real power loss. In addition, we will require that the transmission provider indicate, either in its tariff or on its OASIS, what the energy and capacity loss factors would be for any transmission service it may provide so that potential customers will know the amount of losses to replace".*[49]

This implies that Real Power Loss for Network Service would need to be system average postage stamp losses. But FERC was silent on Point-to-Point loss treatment and it has been treated differently by different tariffs. Hydro Quebec use a postage stamp loss factor of 5.4% because by law they are required to apply *"uniform rates throughout the territory".*[50] NB Power utilizes a postage stamp loss factor of 3.3% mainly because "*tightly meshed transmission networks like New Brunswick have generally all adopted the postage stamp approach*".[51] NSPI on the other hand with a linear system stretching

[49] FERC Order 888, pages 217-218
[50] An Act respecting the Régie de l'énergie, Section 49(11)
[51] **NB Power Transmission Tariff Design Report** (Attachment D), page 32, lines 12-13

over 500 miles chose to apply different path based losses for Point-to-Point service dependent on the Points of Receipt and Points of Delivery.

The configuration of the MECL system has wind generation at each end of the system and the interconnection to New Brunswick in the middle along with most of the load and thermal generation. It is fairly balanced such that system wide postage stamp losses are appropriate. At issue is whether they are determined annually or monthly. Because losses in a power system vary relative to the square of the system load they are relatively higher in winter and lower in other seasons. An annual loss factor will be less than actual losses in high load periods and higher than actual losses in low load periods. A monthly loss factor more appropriately matches the loss obligation of a Transmission Customer with the operational requirements of the system. It is fairer for both Transmission Customers and the Transmission Provider. WKM agrees with the current monthly methodology applied by MECL in the interim OATT and recommends that it continue in the proposed updated OATT.

2. <u>System Costs/Credits</u>

When a new load or generator is connected to the transmission system there may be a change in the Real Power Loss of the system, a change in the dispatch of generation resources, or an increase in system usage with associated reduction in transmission service rates. There also may be a need for expansion of transmission facilities beyond those required for the specific connection. Those specific connection costs are directly assigned to the load or generator so they do not impact other Transmission Customers.

Regarding expansion of facilities, FERC Order 888 provided direction regarding recovery of those expansion costs. Some parties argued that the Transmission Customer causing the expansion should pay both the transmission service rate “and” the costs of the upgrades while others argued that costs should be capped at the “higher of” the transmission service rate “or” the cost of the expansion but not both. FERC’s ruling was as follows:

> *“We continue to believe that "or" pricing sends the proper price signal to customers and promotes efficiency. Under the tariff, any assignment of future expansion costs must meet the standards for conforming proposals in the Transmission Pricing Policy Statement. Recovering expansion cost based upon "and" pricing will not be allowed”.*[52]

This “or” or “higher of” consideration of transmission expansion costs has been retained by FERC in Order 890 as follows:

[52] FERC Order 888, pages 312-313

> *"We are not modifying the existing mechanisms to allocate costs for projects that are constructed by a single transmission owner and billed under existing rate structures. Our intent is not to upset existing cost allocation methods applicable to specific requests for interconnection or transmission service under the Pro Forma OATT".*[53]

In MECL's interim OATT the "or" pricing cost allocation for new projects is the method employed as specified in Attachment K – Transmission Expansion Policy. The same "or" pricing policy, similar to that employed by NB Power, is included in Section 5.6 of the revised Attachment K – Transmission System Planning in the proposed OATT.

Within these OATT attachments there is provision to provide credits for system benefits *"in situations where a request (or requests) for point-to-point or network service requires a transmission network upgrade"*[54] If there are system benefits "*the requirement of the Transmission Customer to make a contribution to capital is diminished by the net present value of the system benefits".*[55]

The corollary to this is that if it is not a situation *"where a request (or requests) for point-to-point or network service requires a transmission network upgrade*" there is no provision in the OATT for credits for system benefits. A simple connection of a load or a generator or a request for service not requiring network upgrades is handled as an incremental roll in to the OATT. A new load's or generator's impact on system dispatch is a market issue and is not considered in the OATT. A load usually increases the cost of Real Power Loss but reduces transmission service rates because of increased usage. Both are effectively socialized in a postage stamp rate. A generator connection may reduce or increase Real Power Loss but it, along with increased usage if any, is also socialized in a postage stamp rate.

This roll in approach is not new to the electric utility sector. It is similar to all rate classes for bundled electricity service. When a new customer load is added to the system it is not charged at the incremental cost of meeting its load. Rather, its load is added to the class load and its incremental costs are added to the class costs. Both are rolled into the class data and the resulting average rate for the class is charged to all customers in that class.

This roll in approach is the norm but it does not mean that there could not be some additional sharing of the system benefits with the Transmission Customer. Because the increased usage of the contributing customer will lower the OATT rate the customer gets some benefit. If the customer's benefit contribution is large some of the benefit might be provided to the Transmission Customer through transmission rate discounts. The

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[53] FERC Order 890, paragraph 558

[54] MECL Interim OATT, Attachment K and MECL Redlined OATT, Attachment K,, Section 5.6.1

[55] Ibid, Section 5.6.4(d).

discount has limitations as we will see in the next section. It cannot be singled out for a specific customer but has to be available at the same point of delivery for other customers. It is the understanding of WKM that this approach was instituted to recognize the additional benefits provided by the West Cape wind generation project.

During comment period on the NOPR for Order 888 several parties argued for cost credits for customer-owned facilities. These relate to situations where facilities owned by a generator or Network Customer might enhance the Transmission Providers system as follows:

> *"(a) increase the transfer capability of an interface on the transmission provider's system; (b) provide an alternative path for power flows during transmission facility outages, thus increasing the reliability or stability of the combined system; or (c) otherwise satisfy the transmission provider's planning criteria for the installation of network facilities"*.[56]

FERC was unable to finalize a standard approach to consider credits for customer-owned facilities other than to require that it "*must be demonstrated that a transmission customer's transmission facilities are integrated with the transmission system of the transmission provider."*[57] Also, if parties could not reach agreement on appropriate credit they could file will FERC for a resolution.

Order 890 continued to maintain the same position. "*For point-to-point customers we retain most elements of our existing policy respecting the crediting of customer-owned facilities, including the requirement that such facilities meet the integration standard."*[58]

This issue of credit for customer owned facilities is not an issue for MECL. The only customer owned facilities on PEI are some of the GTRA connection transmission lines. Other than connect the respective generators they do not provide any of the benefits in quote 55 above.

3. <u>Discounts</u>

FERC Order 888 provides the opportunity for the Transmission Provider to offer discounts on non-firm Point-to-point service and on ancillary services. The objective of discounts is to increase usage of the system and therefore reduce rates for all customers but it set out restrictions to ensure that offering discounts would be non-discriminatory.

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[56] FERC Order 888, Page 314

[57] Ibid, Page 316

[58] FERC Order 890, Paragraph 85, page 60

> *"If a transmission provider offers a rate discount to its affiliate, or if the transmission provider attributes a discounted rate to its own transactions, the same discounted rate must also be offered at the same time to non-affiliates on the same transmission path and on all unconstrained transmission paths. We will further require that any affiliate discounts from the maximum firm rate must be transparent, readily understandable, and posted on the transmission provider's OASIS in advance so that all eligible customers have an equal opportunity to purchase non-firm transmission at the discounted rate."*[59]

These restrictions have been included in Schedules 7 and 8 of the MECL interim OATT using the same wording as the NB Power and FERC *Pro Forma* OATTs. In Order 890 FERC altered the wording for these schedules to be as follows:

> *"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."*[60]

In Order 890 FERC upheld this discounting policy and in addition adopted *"the NOPR proposal to add price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service"*.[61]

MECL's discount policy is *"Reservations for off-Island electricity exports will be discounted to off-Peak rates during periods when transmission path(s) for export are unconstrained.*"[62] The policy encourages wind generation on the Island for export off-Island. It increases transmission usage that is beneficial for all Transmission Customers because it reduces transmission rates for both Network Service and Point-to-Point customers. WKM agrees that it is a reasonable approach and that it is compatible with FERC policy.

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[59] FERC Order 888, Pages 319-20
[60] FERC 890 *Pro Forma* OATT Schedules 7 and 8
[61] Ibid, Paragraph 1410
[62] MECL Redlined OATT Schedules 7 and 8

VI STANDARDS OF CONDUCT

1. Origins and Evolution of Standards of Conduct

Standards of Conduct were first required in 1988 through FERC Order 497 to ensure that interstate natural gas pipeline companies did not provide their gas marketing affiliates with an undue preference in obtaining pipeline transmission service. In 1996 FERC adopted a similar set of standards for the electric utility industry in Order 889, which was issued in parallel with Order 888. As with the natural gas standards, the electric Standards were designed to prohibit vertically-integrated public utilities from giving undue preference to their wholesale merchant functions or to any affiliated marketing entities that might seek access to their transmission network. The electricity Standards of Conduct functionally separated transmission service employees from those affiliated employees who engaged in merchant transactions, and required that access to the transmission network be non-discriminatory through an OASIS.

The Standards of Conduct in the current interim OATT are patterned off those implemented by NB Power in 2003 which in turn were based on the Order 889 requirements. Since 2003 FERC has set out more requirements in Order 717 (and associated rehearing orders) for implementation of Standards of Conduct.

2. FERC Order 717 Requirements

In FERC Order 717 three specific rules have been designed to guide the functional separation and to prevent disclosure of non-public transmission information to the Transmission Providers merchant affiliates.

Independent Functioning Rule – This rule prohibits the transmission function employees ("TFEs") who are responsible for implementing the transmission tariff and processing requests for service from also being involved in marketing power, either on behalf of the utility or an affiliate. This principle ensures that the TFEs will operate wholly separate and apart from the market functions employees ("MFEs"). The rule also requires physical separation between the two groups and prohibits marketing employees from having access to otherwise non-public transmission information. MFEs are restricted from access to transmission areas, such as a utility's control center, where they might gain access to such non-public information.

TFEs adhere to the Standards of Conduct under which they agree not to communicate non-public transmission information to MFEs on an unduly discriminatory or preferential basis. Communication is to be via OASIS and available to all Transmission Customers. It is important to note that TFEs and MFEs are those employees with "day-to-day" responsibility for conducting these functions. Transmission planners are not in this category unless they perform studies used by the TFEs to process requests for transmission service. Employees who are engaged exclusively in arranging power purchases to serve the utilities native load and do not do day-to-day marketing are not categorized as MFEs. (Note that this is an important point for MECL because it does not conduct day-to-day marketing so has no employees that should be designated as MFEs.)

FERC acknowledges that there are communications that are legitimate other than through OASIS. A Transmission Customer can seek information about a pending request for service. Compliance with reliability standards may require coordination between transmission and generation operations employees and involve non-public transmission information. And when circumstances arise that jeopardize system reliability, the utility should be able to take all reasonable actions to address those circumstances, including having TFEs communicate directly with MFEs.

No Conduit Rule - All officers, employees, contractors, consultants or agents of the utility are prohibited from serving as a conduit of Transmission Information to MFEs. *"For example, a senior manager of the company with knowledge of non-public transmission matters, or an outside service provider such as an accountant or an attorney who may work closely with transmission and marketing employees, may not, under the rule, disclose non-public transmission information to a market function employee".*[63] This "No Conduit Rule" is intended to prevent indirect breaches of the Independent Functioning Rule. It requires that potential conduits must be aware of their obligations and trained regarding the Standards of Conduct. And if non-public transmission information is improperly disclosed it must immediately be posted on OASIS and/or the company's internet website in order to level the playing field and enable all transmission customers to have access to this information on a timely basis.

Transparency Rule - Transmission Customers must have confidence that they can obtain information about transmission availability and secure transmission service on the same basis as the utility's marketing employees who may be located in the same building or down the block. Hence, FERC requires that transmission information be broadly available to existing and potential transmission customers through an OASIS. In addition to publishing an inadvertent disclosure of non-public transmission information, FERC requires that the Transmission Provider make public on its OASIS (or public internet site) sufficient information to enable third parties to monitor compliance with the Standards of Conduct. Information should include compliance procedures, affiliate information, shared facilities office arrangements, job titles and descriptions, and transfers whereby a TFE becomes an MFE or vice versa.

[63] NB EUB Matter #229, NB Power Standards of Conduct, Document NBP1.09, page 5, lines 21-25

3. MECL Implementation of Standards of Conduct

NB Power updated its Standards of Conduct (including Procedures for their Implementation) and had them approved by the NB EUB April 22, 2014. WKM and NB Power's expert witness[64] agree that they are compatible with FERC Order 717. They in turn have been modified for MECL implementation in the proposed OATT.

MECL has TFEs that must be subject to the Standards of Conduct but their interaction is with only one Network customer and two Point-to-Point customers. As we stated earlier, considering the "day-to-day" measure for power marketing, MECL does not have any qualifying MFEs. Their merchant function is limited to arranging purchases to supply their native load customers and it is not classified as an MFE activity by FERC. Nonetheless, proper adherence to the Standards of Conduct is appropriate for MECL TFEs and in preparation for possible future MFEs.

It should be noted that FERC and NB Power have removed the Standards of Conduct from the OATT and make them stand alone requirements. MECL also proposes that the Standards of Conduct be removed from the OATT and posted separately on its web site. Rather than have separate hearings for the OATT and for the Standards of Conduct a single hearing dealing with both is more efficient especially considering the amount of transmission transactional activity under the MECL OATT. Consequently, MECL has filed its proposed Standards of Conduct along with its proposed OATT for IRAC approval in this hearing.

VII OPEN ACCESS SAMETIME INFORMATION SYSTEM

Terms and conditions regarding Open Access Same-Time Information Systems and Standards of Conduct are set forth by FERC in regulation 18 CFR § 37 (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and regulation 18 C.F.R. § 38 (Business Practice Standards and Communication Protocols for Public Utilities). FERC jurisdictional utilities are legally bound to follow these regulations but Canadian utilities are not. NB Power proposed to set out the terms and conditions regarding the OASIS in Attachment P of its OATT and states such in Section 4 of the proposed OATT. This approach was not challenged by any interveners and has been accepted by the NB EUB. As such, it is an appropriate approach for MECL.

The recognition of NAESB standards by reference, as required in FERC Orders 676 and 697 is also included in Section 4 of the Fro Forma OATT as follows:

[64] NB EUB Matter #229, Evidence of Stephen J. Ross, Document NBP1.07, page 14, lines 3-9

"Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in Attachment P and in the Transmission Provider's Standards of Conduct in Attachment L. In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this OATT pursuant to Sections 19 and 32.

The Transmission Provider shall post on OASIS and its public website an electronic link to all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The Transmission Provider shall post on OASIS and on its public website an electronic link to the NAESB website where any rules, standards and practices that are protected by copyright may be obtained. The Transmission Provider shall also post on OASIS and its public website an electronic link to a statement of the process by which the Transmission Provider shall add, delete or otherwise modify the rules, standards and practices that are not included in this tariff. Such process shall set forth the means by which the Transmission Provider shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the Transmission Provider deems appropriate."

It is noted in Attachment P that not all of the interactive capabilities of the FERC regulations will be operational in the MECL OASIS. Automatic modification of Network Resources, similar to NB Power, will not be available and will require manual notifications and subsequent OASIS postings by the OASIS administrator. Initially, transmission service requests will also require manually processing. This should not be an issue. FERC in its *Pro Forma* in Section 17.1 recognize that automatic interchange with OASIS may not be available and MECL has included this in its proposed OATT including use of email in addition to telefax.

"Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax [or email], *or (ii) providing the information by telephone over the Transmission Provider's*

time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application".[65]

MECL has one Network customer and two Point-to-Point customers and no internal marketing function activity. All of the information and processing required to provide non-discriminatory transmission access will be provided manually through the MECL OATT administrator and posted on the MECL OASIS. This is the most economically efficient means at this time. When, and if, MECL transmission activity increases it is proposed that the need at that time for full automatic OASIS operation be re-visited. .

[65] FERC Pro Forma OATT Section 17.1

ATTACHMENT A

Resume of William K. Marshall, P. Eng.

Contact Information

653 Aberdeen St, Fredericton, NB, E3B 1S6
(506) 454-8230 (Phone)
(506) 470-9171 (Cell)
Bill.Marshall@rogers.com

Education

BSc (Electrical Engineering) from University of New Brunswick in 1968
BEd (High School & Post-Secondary) from Mount Allison University in 1971
MScE (Power Systems) from University of New Brunswick in 1972
Several courses in Accounting and Finance, UNB, 1978-1983

Professional Experience

President, WKM Energy Consultants Inc since July 1, 2008
President and CEO, New Brunswick System Operator, Oct 2004 – June 2008
Director - Strategic Planning, NB Power Corporation, 1996-2004
Manager - Power Supply Planning, NB Power Corporation, 1991-1996
Senior Engineer – Power Supply Planning, NB Power Corporation, 1983-1991

Eight (8) years as a professional educator at the high school, community college and university levels.
Eight (8) years as a private engineering consultant with work related to energy policy development, computer systems, educational services and power systems planning, tariffs and market issues.
Twenty eight (28) years as a professional engineer in the electric utility industry with NB Power Corporation (24 yrs) and with New Brunswick System Operator (4 yrs) with responsibilities involving:

- power system analysis, planning and development
- integrated resource planning and procurement
- electricity market rules and operations
- environmental strategies and compliance
- cost/benefit analysis of T,D&G equipment upgrades

- reliability standards development, enforcement and compliance, energy policy development
- electric industry restructuring and deregulation
- cost of service and industrial interruptible rate design
- transmission tariffs and ancillary services rate design
- regulatory approvals of tariffs, rates and policies
- renewable energy procurement and wind power integration
- financial forecasting and budgeting
- end use load control and “smart grid” evolution

Related Experience

Memberships and participation in various committees, work groups and task forces at the company, provincial, regional, national and international levels as follows:

- Province of New Brunswick
  - Energy Policy Committee
  - Electricity Market Design Committee
- East Coast Regional Transmission Organization Development Group
- Government of Canada
  - Forecast Working Group of Climate Change Task Group
  - Inter Provincial Electricity Trade Working Group
  - Atlantic Energy Gateway Resource Development and Transmission Planning Technical Committees
- Northeast Power Coordinating Council (NPCC)
  - Load and Capacity Task Force
  - Capacity Planning Work Group 5 – Interconnection Reliability
  - Reliability Coordination Committee
- Maritimes and Northeast Pipelines LLP Tolls and tariffs Working Group
- Maritime Provinces Utility Planning Committee and the Atlantic Electricity Working Group
- Canadian Electricity Association (CEA)
  - Operations and Reliability Section
  - Climate Change Steering Committee
  - Fossil Utilities Climate Change Work Group
- CIDA sponsored Bhutan Project administered through University of New Brunswick
- CIGRE Task Force 38-03-10 on Composite Reliability (Co chairman)

Participation as a witness before hearings of various administrative boards and government committees including

- Crown Corporation Committee of the NB Legislature
- Select Committee on Energy of the NB Legislature
- Select Committee on Wood Supply of the NB Legislature
- Board of Commissioners of Public Utilities of New Brunswick (PUB)
- Energy and Utilities Board of New Brunswick (EUB) including recognition as an expert in power systems planning, operations and transmission tariffs
- National Energy Board of Canada (NEB)
- Régie de l'énergie of Québec including recognition as an expert in power systems planning, operations and transmission tariffs
- Maine Public Utilities Commission
- Nova Scotia Utilities and Review Board including recognition as an expert in power systems planning, operations and transmission tariffs

Writing and presentation of various technical papers, courses and seminars before various groups including

- Institute of Electrical and Electronic Engineers (IEEE)
- Canadian Electricity Association (CEA)
- Canadian Nuclear Association (CAN)
- Canadian Pulp and Paper Institute (CPPI)
- Atlantic Power Summit
- Atlantic Energy Conference
- Québec Electricity Forum
- Ontario Power Symposium
- Northeast Power Coordinating Council (NPCC)
- Canadian Association - Members of Public Utility Tribunals (CAMPUT)
- Association of Professional Engineers of New Brunswick (APENB)
- Committee internationale de grande reseau electric (CIGRE)
- Point Lepreau Operator Training Program
- ClickSoftware Global Utility Summit
- International T&D Summit
- St Thomas University Public Forum on NB Power/Hydro-Quebec Deal
- University of New Brunswick Public Forum on Future of NB Power
- Atlantic Renewable Energy Conference
- Canadian Wind Energy Association Atlantic Caucus Conference
- Atlantic Provinces Economic Council Conference

Power System Planning, Operations and Transmission Tariffs

While at NB Power:

- Integrated Resource Planning Studies for NB Power in 1991, 1995 and 2001 that included distribution, transmission and end use demand side management (DSM) resources as well as conventional generation supply resources
- Economic evaluations of various power systems projects including:
  - Distribution transformer replacements and 25 kV upgrades to 12 kV distribution circuits,
  - Major transmission projects including the NB-HQ Madawaska HVDC interconnection, the NB-NE second 345 kV interconnection and various projects internal to NB,
  - Economic dispatch of generation including optimization of system losses and provision of ancillary services.
  - Environmental emission upgrades of generators.
- Participation on NB policy committees since 1996 regarding utility and market restructuring, open non-discriminatory transmission access and reciprocity requirements of FERC Order 888 that lead to NB White Paper Energy Policy (2001), NB Open Access Transmission Tariff (2003), NB Electricity Act (2003) and NB Market Rules (2004)
- Interventions regarding HQ TransEnergie's OATT Application to the Régie de l'énergie of Québec (2001)
- Design and development of the NB Open Access Transmission Tariff (OATT) and Lead witness before the NB Public Utilities Board for its approval (2002-2003)

While with New Brunswick System Operator (2004-2008):

- Administration of the NB OATT and the NB Electricity Market
- Direction of wind power integration studies and regional transmission studies
- Negotiation of Coordination Agreements with NS Power and ISO-NE, etc.
- Implementation of NBSO as Reliability Coordinator of the Maritimes Area
- Administration, approval and compliance of NERC standards and NPCC criteria
- Development of transmission planning standards, consultations and procedures
- Initiation of "Smart grid" project for water heater control with UNB and SJEnergy

As an independent consultant (2008-2016):

- Witness before NB regulator for amendments to NB OATT
- Completion of a discussion paper for NB Energy in 2008 outlining a sustainable energy development strategy for the Atlantic region involving transmission expansion and new hydro, nuclear and large scale wind generation.
- Extensive stakeholder consultation for NB Energy regarding the NB Electricity market and the structure of NB Power
- Report to a western Canadian utility regarding the transmission and operational challenges of integrating a large nuclear station into the western power grid

- Assist Ontario Energy Board in development of filing guidelines for Transmission and Distribution planning (Sub contract to Power Advisory LLC)
- Assist the NB government in the analysis, negotiation and implementation of the proposed sale of NB Power to Hydro Quebec
- Advisory consultant to the Government of Canada (through Atlantic Canada Opportunities Agency and Natural Resources Canada) for power systems studies under the Atlantic Energy Gateway project.
- Negotiating consultant to the Prince Edward Island Energy Corporation to assist in the evaluation of long term power supply offers from different regional suppliers, to assist the PEI Energy Commission in its review of the electricity sector on PEI and review of the potential for natural gas fired generation on PEI.
- Testimony before, and recognition as an expert witness by, the Régie de l'énergie of Québec regarding amendments to the HQ TransEnergie OATT (2011) and the Characteristics of a Wind Integration Service sought by HQ Distribution (2014)
- Testimony before, and recognition as an expert witness by, the Nova Scotia Utilities and Review Board regarding approval of the Maritime Link under sea HVDC transmission connection between Nova Scotia and the Island of Newfoundland (2013)
- Testimony before, and recognition as an expert witness by, the NB Energy and Utilities Board regarding approval of NB Power Open Access Transmission Tariff (2015)
- Preparation and submission of an expert report on behalf of Nalcor Energy Marketing Corporation in its Complaint against HQ TransEnergie before the Régie de l'énergie of Québec (2016)

Papers and Presentations

Marshall,WK and Smolinski,Walter, Field Tests of the Dynamic Performance of a Synchronous Machine, presented to IEEE Meeting, New York, February, 1973.

Marshall,WK and Hill, EF, Power System Reliability Analysis (Volume 2) Composite Power System Reliability Evaluation – A Summary, presented to CIGRE Symposium, Montreal, September 1991.

Marshall,WK, Demand Side Management, presented to Atlantic Regional Thermal Conference, Fredericton, May 1992.

Marshall,WK and Losier, Michel, Non Utility Wood Fired Generation Projects in New Brunswick, presented to CEA conference "Planning Our Electric Future – Now", Montreal, November 1992.

Marshall,WK and Hill,EF, Risk Assessment of Transmission Alternatives by Means of Composite Reliability Analysis, presented to CEA conference "Planning Our Electric Future – Now", Montreal, November 1992.

Marshall, WK and Hill, EF, Matching Electricity Supply and Demand, presented to Canadian Nuclear Association Conference, Saint John, June 1993.

Marshall,WK and Milton, BE, A Monte Carlo Based Method for Establishing Reserve Margin Criteria, presented to CEA Electricity 95 Conference, Vancouver, March 1995

Marshall,WK, Electricity Deregulation in New Brunswick, presented to CEA Electricity 98 Conference, Vancouver, March 1998.

Marshall,WK, Private Industrial Generation in a Competitive Electricity Environment, presented to Canadian Pulp and Paper Industry Association, Montreal, February 2000.

Marshall,WK, Deregulation of the Electricity Industry, presented to Crown Corporations Committee of NB Legislature, Oct 2000

Marshall,WK, New Brunswick Energy Policy, ECTO Stakeholder Meetings, Moncton, April 24-25, 2001

Marshall,WK, NB Power Transmission System, NB Market Design Committee, July 26, 2001

Marshall,WK, Congestion Management Strawman, NB Market Design Committee Presentation, Sept 27, 2001

Marshall,WK, Comments on the Hydro Quebec Transmission Tariff, presented to Quebec Electricity Forum, Montreal, November 2001.

Marshall,WK and Porter, GP, NB Power Transmission Tariff Design, submitted in evidence to NB PUB, June 2002

Marshall,WK, NB Electricity Market, Presented to Atlantic Gas Conference Halifax July 17, 2002

Marshall,WK, NB Electricity Market Seams Issues, presented to Northeast Power Coordinating Council, Albany, Sept 18, 2002

Marshall,WK, Energy in New Brunswick , presented to Association of Proffessional Engineers of NB Annual Meeting, Saint John, Feb 21, 2003

Marshall,WK, Maritime Canada Electricity Market Issues, Presented to Interjurisdictional Power Transactions Conference, Toronto, March 17, 2003

Marshall,WK, Atlantic Canada Electricity Market Issues, Presented to CAMPUT 2003 Conference, Banff, May 6, 2003

Marshall,WK, Power Deregulation In New Brunswick, presented to Canadian Manufacturers and Exporters Workshop, Fredericton, May 29, 2003

Marshall,WK, Maritimes Area Transmission & Market Issues, presented to Atlantic Power Conference, Halifax, July 15, 2003

Marshall,WK , New Brunswick Transmission & Market Issues, presented to NPCC Annual Meeting, Halifax, Sept 18, 2003

Marshall,WK, Economics of Power Generation for Maritime Canada, presented to Atlantic Power Summit, Saint John, NB., Oct 31, 2003

Marshall,WK, Competition, Restructuring and Markets in Maritime Canada, presented to Alberta Power Summit, Calgary, Feb 13, 2004

Marshall,WK , Competition, Restructuring and Markets in Maritime Canada, presented to ENERCOM Conference, Toronto, March 3, 2004

Marshall,WK , Northeast Reliability Interconnect Project, Pre Application Meeting, Maine Public Utilities Commission, March 22, 2004

Marshall,WK, Potential for Regional Integration of Markets, presented to Atlantic Power Conference, Halifax, NS, May 17, 2004

Marshall,WK, Atlantic Provinces Electricity Supply Issues, presented to Atlantic Energy Ministers Meetings, Mill River PEI, June 7, 2004

Marshall,WK, NB Electricity Market Participation, presented to Atlantic Power Conference, Saint John, June 14, 2004

Marshall,WK , Atlantic Provinces Electricity Supply Issues, presented to Atlantic Gas Symposium, Halifax, NS, July 20, 2004

Marshall,WK , New Brunswick Electricity Market, presented to IEEE LESCOPE Conference, Halifax, NS, August, 2004

Marshall,WK NB Market Implementation, presented to NPCC Annual Meeting, Montreal, Sept 29, 2004

Marshall,WK, NB Market Update, presented to Atlantic Power Summit, Saint John, NB, Nov 1, 2004

Marshall,WK, Barriers to Wind Development - A Maritimes Perspective, presented to NRCan Renewable Energy Working Group Workshop, Ottawa, May 4, 2005

Marshall,WK, NBSO Regional Initiatives, presented to NBSO Annual Conference, Moncton, NB, April 10, 2006

Marshall,WK Supply/Demand Outlook and Other Issues, presented to Atlantic Power Symposium, Halifax, NS, June 5, 2006

Marshall,WK Wind Integration & Tariff Issues, presented to Ontario Power Conference, Toronto, June 15, 2006

Marshall,WK et al, Maritimes Area Wind Integration Issues, submitted to CIGRE CANADA Conference on Power Systems, Montreal, Oct1-4, 2006

Marshall,WK, Tariff, Market and Transmission Issues in Atlantic Canada, presented to Atlantic Power Summit, Saint John, NB, October 30, 2006

Marshall,WK, Transmission Development Issues, presented to T&D Summit, Santa Ana Pueblo, NM, November 6, 2006

Marshall,WK, Market Seams Issues, presented to CEA/CAMPUT Workshop, Toronto, Feb 14, 2007

Marshall,WK, NBSO Activities, NB-Maine MOU and Wind Policy Considerations, presented to NBSO Annual Conference, Fredericton, April 23, 2007

Marshall,WK, Wind Integration Issues in Atlantic Canada, presented to All Energy Conference, Aberdeen Scotland, May 24, 2007

Marshall,WK, Transmission Development Issues, presented to Emerging Energies Conference, Calgary, May 28, 2007

Marshall,WK, Greening of Electricity Consumption in Canada, presented to Standing Committee on Natural Resources of Canadian Parliament, June 4, 2007

Marshall,WK, Wind Policy Considerations For Maritimes Area, presented to Atlantic Power Symposium, Halifax, June 5, 2007

Marshall,WK Electricity Opportunities and Challenges, presented to Conference of New England Governors and Eastern Canadian Premiers (NEG/ECP), PEI, June 26, 2007

Marshall,WK, Hydro and Wind Development Issues in the Northeast, presented to Canadian Dam Association Conference, St. John's NL, September 24, 2007

Marshall,WK, Leveraging New Infrastructure Northeast View, presented to CEA Power Marketer's Council, Gatineau PQ, October 4, 2007

Marshall,WK, Generation and Transmission Issues, presented to National Energy Board Energy Futures Seminar, Ottawa, January 22, 2008

Marshall,WK, <u>Greening the Grid - Considerations For Maritimes Area,</u> presented to CEA Transmission Council, Toronto, February 7, 2008

Marshall,WK <u>Sustainable Electricity for Atlantic Canada,</u> presented to Atlantic Canada Power Summit, Saint John, NB, September 10, 2008

Marshall,WK, <u>Issues Affecting the Electricity T&D System in North America,</u> presented to Global Utility Summit, Los Angeles, Nov 17, 2008

Marshall, WK, <u>HYDRO QUÉBEC TARIFF RELATIVE TO FERC ORDER 890,</u> SUBMITTED TO THE RÉGIE DE L'ÉNERGIE DU QUÉBEC, JUNE 10, 2009

Marshall, WK, <u>Imbalance Pricing and Related Issues Relative to FERC Order 890,</u> SUBMITTED TO THE RÉGIE DE L'ÉNERGIE DU QUÉBEC, JUNE 18, 2009

Marshall, WK, <u>NB Power-Hydro Quebec Deal</u>, presented to Renewable Energy Conference, Halifax, April 27, 2010

Marshall, WK <u>Future Directions?,</u> presented to U.S. – Canada Clean Energy Dialogue Increasing Trade in Clean Electricity, Chicago, May 20, 2010

Marshall, WK <u>Failure of the NB Power-Hydro Quebec Deal Opens Atlantic Hub Opportunities</u>, presented to Atlantic Power Symposium, Halifax, June 2, 2010

Marshall, WK, <u>NB Power's Future??,</u> presented to University of New Brunswick Energy Symposium, June 10, 2010

Marshall, WK, <u>Regional Collaboration and Transmission</u>, presented to Energy Stakeholder Retreat, June 13-14, 2010, Moncton, NB

Marshall, WK, <u>Imbalance Pricing And Related Issues Relative To FERC Order 890 II,</u> Submitted to the RÉGIE DE L'ÉNERGIE DU QUÉBEC, September 28, 2010

Marshall, WK, <u>Atlantic Electricity Sector Opportunities and Challenges,</u> presented to APEC Annual Outlook Conference, Charlottetown, Nov 5, 2010

Marshall, WK, <u>Atlantic Electricity Sector Challenges and Opportunities</u>, presented to Ideas Festival, St Andrews by the Sea, NB, Nov 26, 2010

Marshall, WK <u>Atlantic Electricity Sector Opportunities and Challenges,</u> presented to ACEC(NB) Annual Meetings, Saint John, April 28, 2011

Marshall, WK, <u>Regional Electricity Cooperation Opportunities and Challenges,</u> presented to Atlantic Business Summit, Toronto, June 2, 2011

Marshall, WK, <u>Lower Churchill Falls Project Opportunities and Challenges,</u> presented to Atlantic Power Symposium, Halifax, June 14, 2011

Marshall, WK, Regional Electricity Cooperation Opportunities and Challenges presented to Canadian German Wind Energy Conference, Halifax, February 23, 2012

Marshall, WK, Lower Churchill Issues, Opportunities and Challenges, presented to UNB HVDC Class, January 30, 2013

Marshall, WK, An Assessment of the Costs and Issues Associated with the Delivery of a Purchase from Hydro Quebec, submitted as evidence to the NSUARB by NSPML, January, 28, 2013

Marshall, WK, Review of HQD Application (Concerning Characteristics of a Wind Integration Service), Submitted to the RÉGIE DE L'ÉNERGIE DU QUÉBEC, November 8, 2013

Marshall, WK, Electric Power Opportunities and Challenges in Atlantic Canada, presented to Fredericton Golden Club, February, 2014

Marshall, WK, Evidence of William K Marshall on behalf of Algonquin Tinker Genco, submitted to NB Energy and Utilities Board, November 14, 2014

Marshall, WK, Evidence of WKM Energy Consultants Inc, submitted to NB EUB regarding NB Power proposed OATT upgrades, January 2, 2015

Marshall, WK, Evidence of William K Marshall on behalf of Nalcor Energy Marketing Corporation submitted to the Régie de l'énergie du Québec, May 16, 2016

<u>ATTACHMENT B</u>

Scope of Work for WKM Energy Consultants Inc

MECL OATT Review

Stewart McKelvey intends to retain WKM Energy Consultants Inc. ('WKM') to review the philosophies and terms and conditions of the MECL OATT as currently filed with the Island Regulatory and Appeals Commission ('IRAC'). This review does not include the rates currently charged by the OATT as they are under review and will be adjusted in the upcoming months. More specifically, Stewart McKelvey is looking for WKM's expert opinion on the following:

1. Is the MECL OATT, as currently filed with IRAC and approved on an interim basis, consistent with relevant FERC orders and principles in regards to:
    a. Elements included in the MECL transmission tariff
        i. Bulk system elements.
        ii. Looped system elements.
        iii. Radial lines serving only load.
        iv. Radial lines serving a single customer with both load and generating assets.
        v. Radial lines serving both merchant and system generating assets.
    b. Losses and Credits
        i. Location-based losses and the philosophies behind those calculations if locationbased losses are used.
        ii. Location-based credits for locating generation such that it reduces overall system losses.
    c. Discounting of Transmission Service
        i. Is there any basis?
        ii. What limitations should be put in place?
        iii. Are there any precedents?
    d. Calculation methodology and postage stamp philosophy

Stewart McKelvey is also seeking WKM's expert opinion on the following:

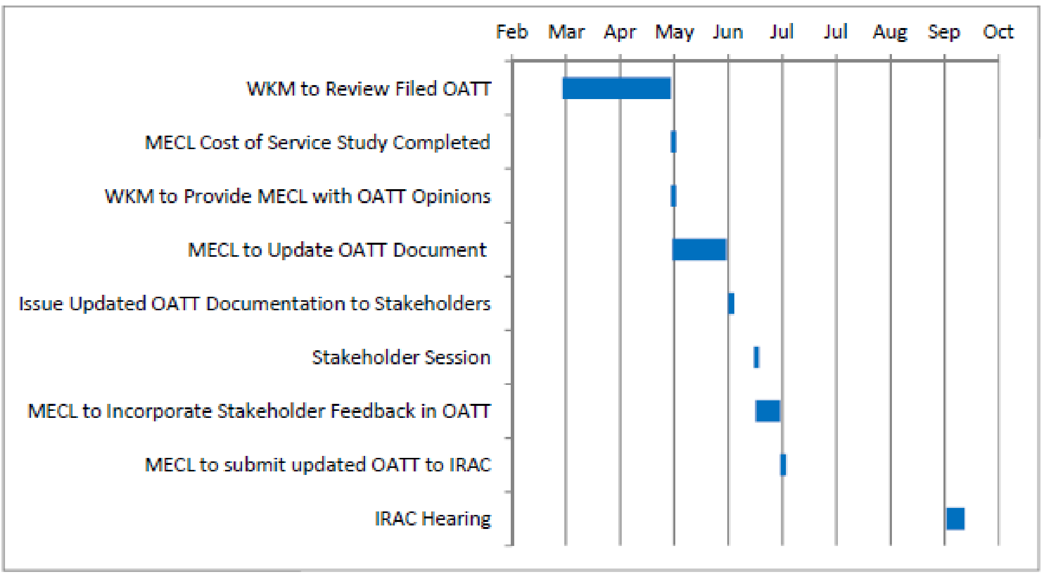
2. Is the current MECL OATT consistent with other regional Canadian transmission tariffs? WKM should highlight philosophical differences at a high level.
3. Is the current MECL OASIS FERC-compliant?
4. Is the current MECL OATT too complicated for the PEI system and energy market? If so, can WKM suggest a simpler model that would meet FERC requirements?
5. What constitutes a long-term financial commitment for transmission, specifically in regards to planning and procurement of long-life transmission and generation assets?
6. How complicated would it be to do zonal or location-based tariffs on PEI?
7. Has MECL's involvement of stakeholders regarding the transmission planning activity in the past year met the intended goal of the relevant FERC orders and policies?
8. Does MECL have appropriate Standards of Conduct in place - ie. does MECL have sufficient business processes or practices in place to ensure that MECL can properly administer the OATT?

Stewart McKelvey may require WKM to review certain evidence that has been submitted to date in the OATT proceedings at IRAC.

Scope of Work for WKM Energy Consultants Inc
MECL OATT Review

Stewart McKelvey requires the results of WKM's work to be presented in a written report format that can be filed with IRAC in future OATT proceedings. If required, WKM must be able to attend an IRAC regulatory hearing and speak to the work completed by WKM in preparing its report. WKM must be prepared to attend and possibly participate in any MECL-led OATT stakeholder session(s) that precede an IRAC regulatory hearing.

Below is a general timeline for WKM's involvement in the MECL OATT review. The timeline is subject to change.



ATTACHMENT C

WKM (NBEUB) IR-2 January 9, 2015

Reference: Exhibit WKM 1.01; Page 6, Lines 3-4

Questions:

a) Please explain how WKM was able to determine that the costs of the proxy generators are reasonable.

b) Has WKM considered the use of actual costs vs. the proxy cost for generators?

c) Please explain why the use of actual costs is not a better methodology for calculating the price for CBAS?

Responses:

a) The proxy unit costs are reasonable for the following reasons:
- They are the costs used by NB Power in its Integrated Resource Plan study and they are in line with the costs published by the US Energy Information Administration and used in their Annual Energy Outlooks.[66]
- The costs employ an escalating capital charge which is the proper manner to compare assets with differing lives. The escalating charge is appropriate because the purchase of ancillary services could be for unknown terms.
- WKM conducted the analysis provided in Attachment E – Proxy unit costs to verify that the escalating costs were correct[67].
- The costs provide credits for reactive supply paid for through Schedule 2 and for installed capacity which is valued at the ISO-NE market price. By deducting the credits NB Power will not be double collecting.

b) No.

c) CBAS services are provided in NB by different generators dependent on load, hydro, wind and fuel price conditions. Determining the actual cost is difficult and would require exposure of generator cost data that is considered confidential in the regional market. Using proxy cost data is transparent and with escalating costs is appropriate for CBAS services.

[66] WKM has data from the AEO 2010 and AEO2014 that are included in Attachment E – Proxy Unit Costs

[67] The capital cost for a conventional CT in the EIA AEO 2014 is incorrect so WKM used data from the AEO2010 for the CT.

NB POWER TRANSMISSION TARIFF DESIGN

June, 2002

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TABLE OF CONTENTS

1.0 INTRODUCTION

An Open Access Transmission Tariff (Tariff) is the foundation upon which competition in electricity supply can occur. It opens the transmission system to all users under consistent non-discriminatory terms and conditions, and charges rates based on the cost of providing services.

There is a significant body of jurisprudence related to the principles to be applied in the design of monopoly services. These have been developed mainly for provision of completely bundled service to end-use customers for the supply of natural gas, electricity, water and telecom services.

The accepted approach is to group similar customers into classes. Costs are then allocated to each customer class based on the principle of "cost causation". The cost of the portion of the system required to service a customer class, which is "used and useful" for that customer class, is allocated to that class. This follows from the need for fairness so that customer classes pay for the cost of the service provided and do not unduly subsidize another class. The overall objective is that rates be "just and reasonable", without "undue discrimination", and based on the "revenue requirement."

This document explains the approach employed by NB Power to design its transmission tariff. While significant advances in transmission tariff rate design have been made, it is important to note that there is, as yet, no universal industry standard. Transmission rate design and pricing methodologies continue to evolve. NB Power's approach closely follows relevant transmission pricing developments in other jurisdictions and applies them within the public policy directions of New Brunswick.

New Brunswick has targeted 2003 for electricity supplier choice to be available for municipal wholesale and industrial customers served from the transmission system. Supply is to be available from self-generation, independent third party suppliers, and also through a standard offer service from NB Power. Implementation requires that unbundled non-discriminatory transmission service be available. In designing the transmission tariff, consideration has been given to the directions of the *White Paper: New Brunswick Energy Policy*[1] and the recommendations of the New Brunswick Market Design Committee[2] in addition to traditional rate making principles.

2.0 TRANSMISSION RATE MAKING PRINCIPLES

This section provides details about transmission rate making principles. The key points discussed are: the evolution of principles applicable to NB Power (Section 2.1); the impact of the *Transmission Pricing Policy Statement* developed by the Federal Energy Regulatory Commission (FERC) in the United States (Section 2.2); the Federal Energy Regulatory Commission's Order 888 *Pro Forma Tariff* (Section 2.3); and, the New Brunswick Market Design Committee's Recommendations (Section 2.4).

2.1 Evolution of Principles Applicable to NB Power

Rate making principles for electric transmission services have been developed only in the last decade. They have been driven mainly in North America by the FERC which is empowered to regulate the *American Federal Power Act* (FPA).

Amendments to the FPA in 1992 provided for competition in electricity supply at the wholesale level, where wholesale is defined as "purchase for resale". Since then the FERC has significantly influenced transmission tariff design with the issuance of both its *Transmission Pricing Policy Statement* (1994) and *Order 888* which includes the *Pro Forma Tariff* (1996).

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[1] Written by the New Brunswick Department of Natural Resources and Energy and released in January 2001. Cited and referred to as the *Energy Policy White Paper* (http://www.gnb.ca/0078/Energy/index.htm).
[2] Established by the Minister of Natural Resources (see *Energy Policy White Paper*, 3.1.3.1) to make recommendations concerning the design, structure, and rules for the development of a wholesale electricity market. The Final Report (April 2002) is available at http://www.nbmdc-ccmnb.ca/final_report.asp

While the FERC has no jurisdiction in New Brunswick, its principles have influenced policy makers here. The New Brunswick Market Design Committee has reviewed transmission tariff issues as part of its work regarding the implementation of supplier choice in New Brunswick. The following sections outline the FERC influence and the relevant transmission tariff recommendations of the Market Design Committee.

2.2 FERC Transmission Pricing Policy

The *Transmission Pricing Policy Statement*[3], issued by the FERC on October 26, 1994, specifies five principles regarding the pricing of transmission services. Instead of promoting a particular approach to rate design, the policy statement provides flexibility in the development of transmission pricing. The FERC recognized that there are a number of workable, non-traditional transmission pricing methods that offer potential improvements in fairness, practicality, and economic efficiency.

The FERC states that the pricing of transmission "be just and reasonable and not unduly discriminatory or preferential"[4]. The Commission elected to permit more flexibility to utilities to file innovative pricing proposals that meet the traditional revenue requirement but only if they satisfy the pricing principles below:

- Transmission Pricing Must Meet the Traditional Revenue Requirement
  "First a utility must determine its total company revenue requirement, the capital component of which traditionally has been measured by embedded (depreciated original) cost. Second, a utility must allocate among individual customers or classes of customers that portion of the total revenue requirement that is attributable to providing transmission services, in a manner which appropriately reflects the costs of providing transmission service to such customers or classes of customers. Finally the utility must design rates to

[3] Inquiry concerning the Commission's pricing policy for transmission services provided by Public Utilities under Federal Power Act; Policy Statement, October 26, 1994, Docket No. RM93-19-000, 18 CFR 2, 59 FR 55031 (http://www.ferc.gov/news/policy/pages/rm93-19.pdf).

recover those allocated costs from each customer class. Different customers may pay different rates if they use the system in different ways".[5]

- Transmission Pricing Must Reflect Comparability

  This principle requires that an *"…open access tariff that is not unduly discriminatory or anti-competitive should offer third parties access on the same or comparable bases, and under the same or comparable terms and conditions, as the transmission provider's uses of its system."*[6]

- Transmission Pricing Should Promote Economic Efficiency

  The FERC specifies that transmission pricing should promote; *"…efficient expansions of transmission capacity; efficient location of new generators and new loads; efficient use of existing transmission facilities…, and, efficient dispatch of existing generating resources".*[7]

- Transmission Pricing Should Promote Fairness

  "As a general matter, transmission pricing should be fair and equitable"[8]. Current transmission customers should not pay for the cost of providing wholesale transmission services to third-parties nor should third-party customers subsidize existing customers. *"The major purpose of transmission pricing reform should be to provide more efficient price signals, particularly for new transmission uses, and not simply to reallocate sunk costs"*[9].

[4] FERC's Transmission Pricing Policy Statement, p5.
[5] FERC's Transmission Pricing Policy Statement, p6, referenced from 67 FERC at 61, 490.
[6] From the FERC's comparability standard (*American Electric Power Service Corporation (AEP)*, 67 FERC 61,168 (1994) at 61,490.
[7] FERC's Transmission Pricing Policy Statement, p7.
[8] FERC's Transmission Pricing Policy Statement, p7.
[9] FERC's Transmission Pricing Policy Statement, p7.

- Transmission Pricing Should Be Practical

  "Transmission pricing should be practical and as easy to administer as appropriate given the other pricing principles"[10].

The FERC refers to pricing proposals as being either "conforming" or "non-conforming." Conforming pricing proposals are based on the first two principles. Initially, innovative non-conforming proposals were considered acceptable, even if they were not based on the first two principles, as long as they produced "just and reasonable" rates. However there now appears to be a preference for proposals that conformed to the first two principles. While the other three principles continue to be viewed as goals that a conforming proposal must strive to meet, achievement is balanced against the need for transmission rates that are "just and reasonable".

2.3 Order 888 Pro Forma Tariff

In 1996 the FERC issued Order 888[11] which, included the Pro Forma Tariff. The order required all utilities under FERC jurisdiction to file a tariff which specified the terms, conditions and a pricing methodology that conformed to the pricing principles. The FERC was still open to non-conforming pricing proposals, but required that the proponent demonstrate that it was superior to the *Pro Forma* approach. In addition, through Order 889[12] the FERC standardized the reservation process through which transmission services could be transacted. This includes the requirement for an Open

[10] FERC's Transmission Pricing Policy Statement, p8.

[11] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities Order No. 888 Final Rule (Issued April 24, 1996), United States Of America 75 FERC 61,080, 18 CFR Parts 35 and 385 [Docket Nos. RM95-8-000 and RM94-7-001] (http://www.ferc.gov/news/rules/pages/order888.htm).

[12] Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct Order No. 889 Final Rule (Issued April 24, 1996), United States Of America 75 FERC 61,078, 18 CFR Part 37 [Docket No. RM95-9-000] (http://www.ferc.gov/news/rules/pages/order889.htm).

Access Same-Time Information System (OASIS) and the Standards of Conduct with respect to non-discriminatory control of third party information. Clarifications to the *Pro Forma* approach have been made through various decisions and rulings of the FERC since.[13]

2.3.1 Pro Forma Transmission Services

Under the *Pro Forma Tariff* the transmission provider is responsible for providing reliable and efficient dispatch and transportation of energy (delivery service only). These services are known as Network Integration Transmission Service (network service) and Point-to-Point Transmission Service (point-to-point service). The transmission provider is not obligated to supply either energy or generation capacity.

Network service is firm transmission service delivered to the high side of the substation transformer. It includes the delivery of both capacity and energy. "*It allows a Transmission Customer to integrate, plan, economically dispatch and regulate its Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load customers. Network Integration transmission Service also may be used by the Transmission Customer to deliver non-firm energy purchases to its Network Load without additional charge.*"[14]

The transmission provider will provide network integration transmission service on a comparable, non-discriminatory basis to network customers. The transmission provider will permit such customers to integrate their designated network resources to service their network loads on a basis that is comparable to the transmission provider's use of the transmission system. Meters will be owned, read, and maintained by the transmission provider.

[13] For Orders 888a and 888b, see (http://www.ferc.gov/news/rules/pages/order888.htm). See (http://www.ferc.gov/news/rules/pages/order889.htm) for Orders 889a and 889b.
[14] FERC Glossary (http://www.tsin.com/gloss.html).

Point-to-point service[15] refers to the reservation of capacity and/or the transmission of energy from a point of receipt to a point of delivery. This service is available on either a firm or a non-firm basis.

2.3.2 Ancillary Services and Curtailments

The *Pro Forma Tariff* requires that the transmission provider make some ancillary services available at regulated rates. Services that must be available are as follows and rates for such services are provided in the tariff under the 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 Reserve - Spinning Reserve Service [Schedule 5]
- 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.

2.3.3 Postage Stamp Rate

A postage stamp rate[16] 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

[15] FERC Glossary (http://www.tsin.com/gloss.html).
[16] Platt's Glossary (www.platts.com).

postage stamps for letters are typically at a fixed price, regardless of their origin and destination. In the *Pro Forma*, both network service and point-to-point service are provided through postage stamp rates.

The *Pro Forma* allocates a relevant revenue requirement to users based on their contribution to the transmission system peak load. The postage stamp rate is determined by dividing the relevant revenue requirement ($/yr) by the applicable peak load (kW) to get an annual rate ($/kW/yr). While the overall method is clear, there are significant issues regarding what constitutes a relevant revenue requirement for what type of service and what peak loads should be used. How NB Power's proposal addresses these issues is detailed in Sections 3 and 4 of this report.

2.3.4 Clarifications to Order 888

Since release of Order 888 there have been a number of decisions that have clarified its application concerning the development of transmission rates. Two such decisions are worthy of note.

Kentucky Utilities Company Opinion and Order

In the original FERC code of accounts generator step up transformers (GSUs) were classified as transmission assets and many utilities included the GSU costs in their original transmission tariff rates.[17] There were a number of interventions before FERC to change this practice and they did so in the Kentucky decision as follows:

> *"Most importantly, in Order No. 888, we [FERC] required the unbundling of transmission and wholesale generation services. We believe it is appropriate to re-examine our policy on the functionalization and the recovery of costs associated with GSUs to ensure that unbundled services customers are paying only their*

[17] Note that most Canadian utilities including NB Power and Hydro-Québec did the same.

appropriate share of the cost of services which they use. …. In short, we find that GSUs are used in the provision of both generation and ancillary services, and that the costs of these facilities should be charged to the customers using the facilities. … we find a more accurate method of cost recovery is to directly assign the costs of each GSU transformer to the generator to which it is connected."[18]

Court of Appeals (D.C.)

A number of utilities challenged the legal authority of FERC to issue Orders 888 and 889 and petitioned for its review. As recently as June 30th, 2000, subsequent to Order 2000 on Regional Transmission Organizations, the US Court of Appeals found in favour of the FERC as follows:

"Open access is the essence of Orders 888 and 889. Under these orders, utilities must now provide access to their transmission lines to anyone purchasing or selling electricity in the interstate market on the same terms and conditions as they use their own lines. … Finding few defects in the orders, we uphold them in nearly all aspects."[19]

2.3.5 Influence Outside the United States

Although the FERC has no direct jurisdiction outside the United States, it has had significant influence on the implementation and design of external tariffs. First, the FERC has instituted a reciprocity requirement on all non-jurisdictional utilities that use the tariffs of jurisdictional utilities. Second, non-jurisdictional companies wishing to sell electric power at market based prices in the U.S. must acquire a power marketing authority license from the FERC. Thirdly, the license requires that the reciprocal transmission access to be provided is done under a tariff that is equal to or superior to the *Pro Forma*. The effect of this latter point has lead to the development and implementation of *Pro Forma* tariffs by utilities in Canada and Mexico. Today the

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[18] November 1998, FERC document 85FERC61,274.
[19] *225 F.3d 667, 2000 U.S. App. LEXIS 15362 (June 30, 2000).*

Order 888 *Pro Forma Tariff* is the most commonly applied tariff in Canada as well as the United States.

2.4 Market Design Committee Recommendations

The *Energy Policy White Paper* has targeted April 2003 as the date by which wholesale and industrial customers served at the transmission level will have their choice of electricity suppliers. As part of the preparation process for the implementation of this level of supplier competition, a multi-stakeholder Market Design Committee was formed to make recommendations to the Minister of Natural Resources and Energy regarding the market structure. A number of these recommendations concern the design and implementation of the transmission tariff.

2.4.1 FERC Order 888 Compatible Tariff

The market structure that is recommended by the Market Design Committee is a physical bilateral contract market.[20] Such a market requires that transactions between buyers and sellers be physically balanced. This means that the power injected at the point of receipt matches the power extracted at the point of delivery. The Market Design Committee recognized the importance to the bilateral contract market of open, non-discriminatory access to the transmission system. They also acknowledged that in 1996 FERC Order 888 established the minimum open access conditions necessary to support a bilateral contract market. As a result the following recommendation was made:

> *"The MDC [Market Design Committee] recommends that the transmission system will provide open, equal non-discriminatory access to all eligible market participants under terms and conditions compatible with FERC Orders 888 and 889. The System Operator will have an Open Access Transmission Tariff* (OATT) *for network and point-to-point service covering transmission service: within the*

[20] Market Design Committee, Final Report, Recommendation 3-1, p10.

province, into the province, out of the province, and through the province The PUB shall approve the OATT."[21]

2.4.2 Charge Determinants for Tariffs and Ancillary Services Charges

The two major issues concerning charge determinants for transmission and ancillary services are (1) coincident system peak load versus non-coincident peak load by delivery point and (2) gross load versus net load for consideration of self-generation.

Although other methods have been approved and implemented, the traditional FERC approach is to allocate costs to the different service classes based on a rolling 12 month average of the monthly coincident peak loads and, where metering is sufficient, to bill individual usage on the same basis. In cases where eligible transmission customers may not have proper interval metering to determine coincident peak contributions the actual customer billing of services has to be done using other billing determinants such as non-coincident peak loads.

Proper interval metering does not exist in New Brunswick at all transmission delivery points. In addition the current billing practice for integrated service in New Brunswick is to use monthly 15-minute non-coincident peak loads for demand billing. As a result the Market Design Committee recommended that:

> *"…the transmission tariff approved by the PUB provide that ancillary services charges to distribution utilities be based on monthly net non-coincident peak demand by delivery point."*[22]

and also that

[21] Market Design Committee, Final Report (April 2002), Recommendation 6-57, p45.
[22] Market Design Committee, Final Report (April 2002), Recommendation 6-71, p54.

"…the transmission tariff approved by the PUB provide that network service transmission charges to distribution utilities be based on monthly net non-coincident peak demand by delivery point."[23]

Gross versus net load is the second issue with respect to billing determinants. Under gross load billing a customer with self-generation would pay for services based on their total peak load, whether or not it was being met by their own generation. This approach was initially allowed by FERC policy[24]. Since then, however, some customers have been permitted to implement this policy in a modified manner. One alternative is that the self-generator pay for services based only on its total load net of its own generation. This approach has been implemented in Ontario.

The time interval over which net load is measured is also a factor. The longer the time interval, the closer net load billing comes to gross load, because the chances are higher that at some time the self-generation facility will not be running. The Market Design Committee noted that net load billing, with a monthly non-coincident peak charge determinant, would likely result in total charges close to those of gross load billing if the self-generator is out-of-service at least once a month for a significant number of months in a given year. The Market Design Committee recommended that:

"…the tariff design approved by the PUB provide that self-generators connected to the transmission system pay for ancillary services on the basis of monthly net non-coincident peak demand."[25]

and that,

"…the transmission tariff approved by the PUB provide that self-generators choosing network service will be charged for transmission service on the basis of their monthly net non-coincident peak demand."[26]

[23] Market Design Committee, Final Report (April 2002), Recommendation 6-72, p54.
[24] See Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC_61, 006 (1998).
[25] Market Design Committee, Final Report (April 2002), Recommendation 6-67, p52.

These recommendations represent a significant change from the current treatment of self-generators. Under current practice, self-generators connected to the transmission system do not pay explicitly for either ancillary services or transmission tariffs. Instead, they can contract for interruptible supply from NB Power as a backup and pay only time-differentiated energy rates. The *Energy Policy White Paper* directed the Market Design Committee to look for ways to avoid rate shock for existing self-generators. No specific recommendations were made except that consideration of the issue should be made by NB Power when it was designing the transmission tariff. The Market Design Committee recommended that:

> *"…the design of the transmission tariff seek to mitigate potential rate shock to self-generators."*[27]

2.4.3 Metering Costs and Data Use

Metering is fundamental to the settlement of all energy flows and some of the ancillary services. All parties must therefore have a high degree of confidence in its accuracy, reliability, and data integrity.

Current practice in New Brunswick is that the NB Power Transmission Business Unit owns the meters for connection to wholesale customers. Generators are responsible for the cost of providing meters at their connection points to the transmission system. The Market Design Committee recommended continuation of this practice and specifically that:

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[26] Market Design Committee, Final Report (April 2002), Recommendation 6-68, p52.
[27] Market Design Committee, Final Report (April 2002), Recommendation 6-69, p53.

" the transmission owner(s) own all meters at injection and withdrawal points from the grid.

- *Transmission owner(s) will act as "meter data service" provider*
  - *Maintain meters*
  - *Responsible for meter data security*
- *Transmission owner(s) will give the data to the system operator for use in billing and settlement*
- *The transmission owners' costs will be included in the transmission tariff."*[28]

and

"…all meters for generation or other injection points to the grid be paid for by the generator."[29]

2.4.4 Ancillary and Security Services

The Market Design Committee considered implementation of market mechanisms for the procurement and delivery of ancillary and security services but because of market power issues recommended that they at least initially be provided as regulated services through the Tariff. The Market Design Committee recommends that:

" balancing energy service be initially provided as an ancillary service through the transmission tariff and that its provision be based on the following principles:

- *It should efficiently provide economic signals that will drive behaviours appropriate for reliable operation of the system*
- *Pricing of the service should be market-based where possible through:*
  - *Offers for increments and decrements*
  - *A proxy market price*

[28] Market Design Committee, Final Report (April 2002), Recommendation 6-63, p49.
[29] Market Design Committee, Final Report (April 2002), Recommendation 6-64, p49.

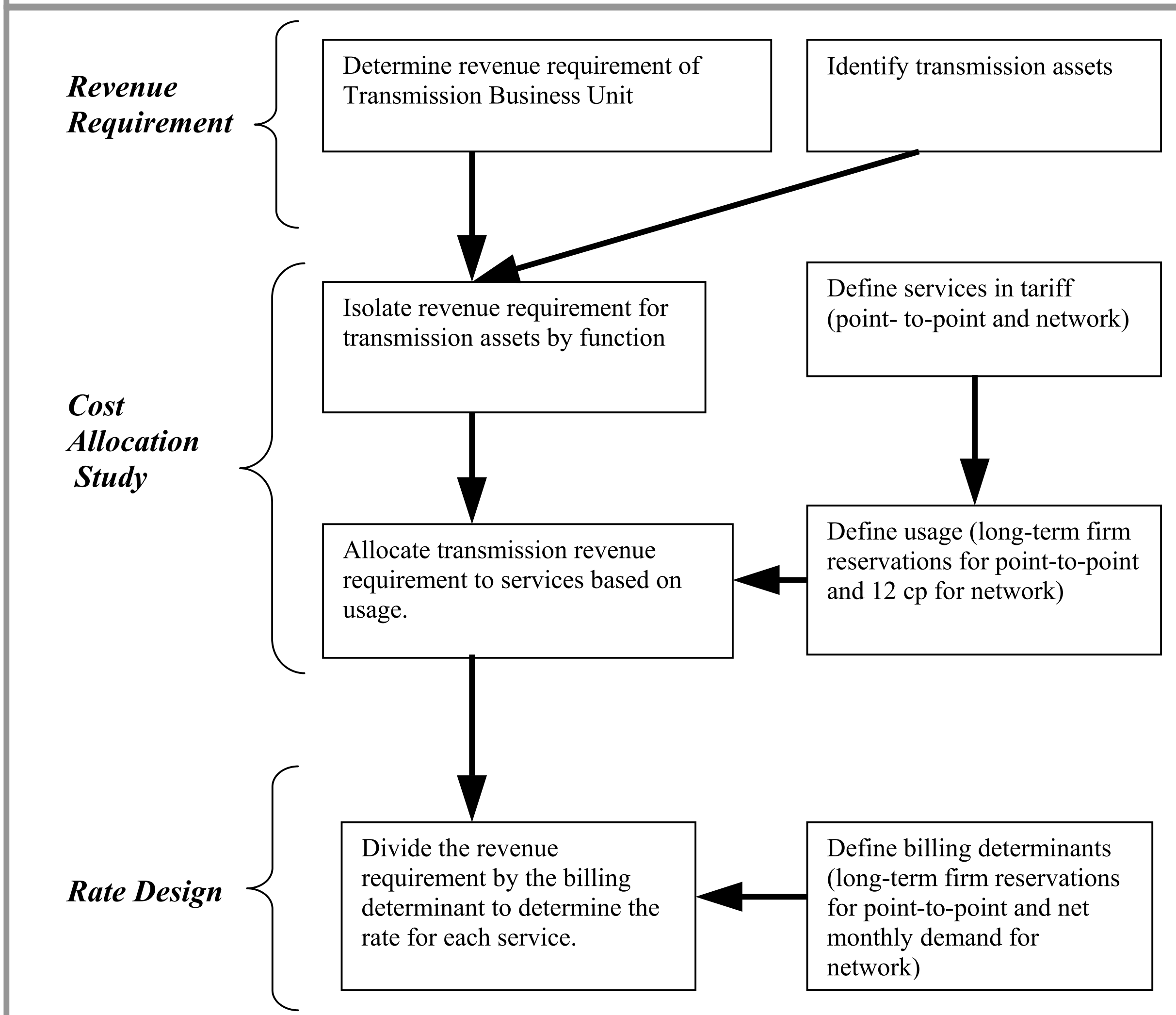
- *Ceilings and floors as necessary to protect participants."*[30]

[30] Market Design Committee, Final Report (April 2002), Recommendation 3-30, p26.

3.0 TRANSMISSION SERVICES COST ALLOCATION AND RATE DESIGN

A transmission tariff defines the terms, conditions and price under which a user (transmission customer) can gain access to the transmission provider's infrastructure (transmission assets). Although the methodology of developing efficient and equitable tariff rates is complicated, it can be simplified to the three-step process illustrated in Figure 3-1.

Figure 3-1: Overview of the Steps taken in the Development of a Tariff.



It should be noted that this process is the same as that detailed in the first pricing principle of FERC. *"First a utility must determine its total company revenue* *requirement, … Second, a utility must allocate … the total revenue requirement … in a manner which appropriately reflects the costs of providing transmission service … Finally the utility must design rates to recover those allocated costs from each customer class."*[31]

3.1 Transmission Revenue Requirement

The first step in designing an efficient and equitable transmission tariff is to determine the appropriate revenue requirement that must be recovered from the sale of services. The total revenue requirement related to transmission services for the NB Power Transmission Business Unit has been determined to be $98.4 million for the test year.

Table 3-1
Transmission System Revenue Requirement

Revenue Requirement Component	$millions
Asset amortization	18.4
OM&A	37.5
Interest, taxes and return on equity	42.4
Total	**98.4**

($0.1 difference due to rounding)

This revenue requirement includes all costs (amortization costs, operation, maintenance and administration costs, finance charges, and payments in lieu of taxes) plus a regulated return on investment. This revenue requirement relates to all transmission assets and has been determined by the Comptroller of the Transmission Business Unit. The components of the revenue requirement are summarized in Table 3-1.

In addition to the costs of all transmission lines at voltages of 69 kV or higher and terminal stations between transmission lines, the revenue requirement includes the costs

[31] Inquiry concerning the Commission's pricing policy for transmission services provided by Public Utilities under Federal Power Act; Policy Statement, October 26, 1994, Docket No. RM93-19-000, 18

associated with the generation step up transformers of NB Power generators. Because some of these assets are not associated with the transmission services offered under the tariff it is necessary to break down the revenue requirement into component pieces for all assets. Only after such a breakdown is completed can costs be allocated to specific services.

Amortization costs are able to be linked directly to specific assets because the gross and net asset value of each asset is accounted for in the company's accounting records. OM&A is allocated to each asset based on gross asset value while interest, taxes and return are allocated based on net asset value.

3.2 Cost Allocation Analysis

The purpose of the cost allocation analysis, which is the second major activity in the development of transmission rates, is to allocate the appropriate revenue requirement (i.e. the costs associated with transmission) to the appropriate services. The following steps are required to do this in a manner that is both efficient and equitable:

- Definition of the transmission services to be provided
- Definition of the basic functions of the transmission system
- Allocation of transmission revenue requirements to the different functional uses of the system
- Determination of system usage by service
- Allocation of the functional costs to the transmission services

CFR 2, 59 FR 55031 [31,143] (http://www.ferc.gov/news/policy/pages/rm93-19.pdf).

3.2.1 Services Defined in Tariff

The Tariff defines two transmission services that are consistent with the FERC *Pro Forma Tariff*: point-to-point and network service. In addition, the ancillary service of Scheduling, System Control, and Dispatch is an obligatory service that must be provided by the transmission provider and taken by the transmission customer. The rate design of these three services are considered here in Section 3, while the rates for the other ancillary services which are supplied by generators are detailed in Section 4 of this report.

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 would be a reservation of 100 MW from the Nova Scotia interconnection to the Hydro Quebec interconnection. This service is available on either a firm or a non-firm basis. The primary points of receipt and/or delivery can also be changed on a non-firm basis to secondary points but only if there is sufficient transmission capacity available after all other uses of the system have been accommodated. In other words, when a firm reservation is used to deliver power between secondary points of receipt or points of delivery, the service provided is subservient to all other uses of the grid, including non-firm point-to-point service. It is usually used for wholesale transactions between systems rather than for the direct supply of load within a system. However it is available for both uses at the discretion of the transmission customer.

Network Service is firm transmission service for the delivery of both capacity and energy to the high side of the substation transformer of the transmission customer. It is usually used for supply of load within the system. Network customers (large industrial and municipal customers) have the option of either owning their own substation transformer or renting this equipment from Customer Service. It is proposed that meters will be owned, read, and maintained by the transmission provider consistent with the recommendations of the Market Design Committee.[32]

[32] See Market Design Committee, Final Report (April 2002), 6.3 Metering, p48.

Scheduling, System Control, and Dispatch Service is required to schedule the movement of power into, out of, through, or within a control area. Only the system operator of the control area in which the transmission facilities are located can provide this service.

It is important to understand that the services described are independent of the voltage level at which the service is provided. In some utilities voltage related discounts are provided to large customers who receive bundled service but this has not been the practice in New Brunswick. Today, the rates for NB Power's large industrial and municipal wholesale customers are not differentiated by voltage.

Throughout North America most utilities have chosen not to provide voltage differentiated rates for unbundled transmission services. There are two main reasons for this approach. Offering different prices for service at different voltage levels would lead customers to request service at the lower price. If the infrastructure is not already in place, the transmission provider could very well incur higher costs. Such an increase would inefficiently shift costs to other users of the system. Furthermore, the transmission provider's mandate to maintain a reliable system may lead to situations where it is preferable for a particular load to be served at a particular voltage level. Where the FERC has jurisdiction, they have deemed that the entire transmission system operates as a single integrated piece of equipment and they have consistently mandated a fully rolled-in approach without voltage differentiation.

3.2.2 Transmission Functions

The services defined in the previous section use different parts of the transmission system. The purpose in this section is to identify which assets are used to provide which services. For the purposes of the NB Power Tariff, assets have been grouped into four main functional groups as follows:

- Generation Related Transmission Assets
- Bulk Network Assets which can be further subdivided into:
  - Interconnections
  - In-Province network
- Local Service Assets
- Energy Control Centre Assets

In order to be able to perform this allocation of the Transmission Business Unit assets and their associated costs it is necessary that the division point between functional groups be defined. The division points and the types of assets allocated to the different functions are explained in detail below:

> Generation Related Transmission Assets (GRTAs) are those assets that serve the function of connecting generation units to the shared transmission system. They consist of generator step up transformers (GSUs), a portion of the terminal assets, and transmission lines whose primary purpose is to connect a generator to the transmission system. The GSUs (also referred to as unit transformers) are easily identified because they are directly connected to the low voltage output of the generator. As noted in Section 2.3.4 these have been ruled by FERC to be assigned 100% to generation since the Kentucky Utilities decision. These GSU costs are often separated from the remaining GRTAs, which are more controversial because of the difficulty in defining a division point between GRTAs and Bulk Network assets. In the cost allocation of the NB Power transmission a portion of the total pool of terminals was allocated to the GRTA function on the basis that each individual generating unit needs a synchronizing breaker position in order to be able to synchronize and connect to the system. Also transmission lines that strictly connect a generating facility to the transmission system were also assigned to the GRTA function. These assets and the associated revenue requirements are to be recovered directly from the generation owners and not collected in the rate for the transmission tariff. For any new generation, the generator is responsible for the cost of any additional generation related

transmission assets that are required to connect the new generator. In the FERC *Pro Forma*, as well as in the filed tariff terms and conditions, these types of assets are referred to as direct assignment facilities.

Bulk Network Assets make up the portion of the transmission system that is highly interconnected and that serves multiple functions. The Bulk Network has two components: Interconnections and In-province assets. Interconnections are comprised of transmission lines that interconnect with external utilities at the provincial border, a portion of the terminals that connect these lines with the remaining system and the high voltage direct current (HVDC) converter station at Eel River. The In-province service consists of all remaining terminal costs (that have not been allocated as GRTAs or to Interconnections) and all transmission lines that are capable to operate as part of the integrated system within the province.

Local Service Assets are those parts of the transmission system which are not a part of the integrated network and used only to serve in-province loads or to connect generators in addition to supplying in province loads. The costs associated with these parts might need to be pooled and charged in a different fashion than the highly shared bulk network. Transmission lines that are configured such that they can only be operated in a radial fashion are 100% assigned to the local service function.

Energy Control Centre Assets that support the operation of the transmission system are in this function. The allocation was based on an assessment of the usage of the NB Power Energy Control Centre building, computer systems, and other related equipment required for system operator functions. These are the functions that are to be charged under the tariff through the service called Scheduling, System Control, and Dispatch.

3.2.3 Functional Allocation of Costs

The allocation of the transmission services revenue requirement of $98.4 million to the functional uses of the system is detailed in Attachment A and the results are summarized in Table 3-2.

Table 3-2
Functional Allocation of Revenue Requirements

Functional Use	Revenue Requirement Share ($millions)
Generator Step Up Transformers (GSUs)	5.1
Non-GSU Generator Related Transmission Assets (GRTAs)	4.5
Bulk Network Interconnections	7.2
Bulk Network In Province	70.9
Local Service	6.3
Energy Control Centre	4.4
TOTAL	98.4

The major issue to be addressed concerning these functional allocations is to determine which costs should be collected through tariff rates and which costs should be collected by direct assignment to specific users. This has been the subject of much debate in both FERC and non-FERC jurisdictions and has often been influenced more by the state/provincial regulator than by the FERC itself.

In some systems the costs associated with non-GSU GRTAs have been deemed to be substantial and are directly assigned to the generators. This also applies in some systems for local service assets and they are only charged to the customers that use them. In some systems interconnections have been included in the base transmission tariff and in some cases interconnections are charged separately from the tariff. In all systems the Energy

Control costs are allocated to the Scheduling, System Control and Dispatch ancillary service.

For the NB Power Tariff, it is proposed that interconnections and local service lines be included with the bulk network because they have relatively low costs and they provide market opportunities to both loads and suppliers. As a result the functional costs are allocated as follows:

- All GRTAs including GSU costs and non-GSU costs are allocated as direct assignment charges to generators ($9.6 million)
- Interconnections, In-province Bulk Network and Local Service costs are the common use portion of the transmission system and are allocated as revenue requirement costs to be collected from transmission services under the tariff ($84.4 million)
- Energy Control Centre costs are allocated to Scheduling, System Control and Dispatch and are to be collected through tariff rates for that service ($4.4 million)

3.2.4 Determination of System Usage

Usage of the system by various services must be defined in order to allow the revenue requirement to be allocated to the services. The challenge with usage is to select metrics for each of the services such that the cost allocation meets the appropriate rate making principles. "Cost causation" and "used and useful" principles are the two most relevant to the issue of what usage to apply for the allocation of revenue requirements.

The allocation of the transmission revenue requirement in the NB Power cost allocation analysis to point-to-point and network services is based on the approach prescribed by the FERC through Order 888. This allocation is based on the principle that the monthly coincident peak system load, or usage, is a fair measure upon which to allocate the revenue requirement of the transmission system. Coincidental peak load is defined as the sum of two or more peak loads that occur in the same time interval.[33] The use of 12 monthly coincident peaks balances the "cost causation" and "used and useful" principles of transmission tariff rate making. Use of a single coincident peak on the New Brunswick system tends to increase the allocation of revenue requirement to network services and understates the usefulness of the system to point-to-point services.

The FERC approach is incorporated in Section 34.3 of the *Pro Forma Tariff* (Determination of Transmission Provider's Monthly Transmission System Load) which states:

> *The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.*[34]

The substitution of point-to-point reservations for actual use is done in recognition of the fact that the transmission provider is fully committing the reserved capacity on a long-term firm basis. The transmission provider must design the transmission system to accommodate the full use of the reserved capacity at any time, including the time of monthly system peaks. No allowance for diversity can be made.

In the case of the NB Power system, the long-term firm reservations for the test year are 720 MW. Therefore, as prescribed by FERC, the long-term firm reservations were used rather than actual usage corresponding to the 12 monthly system peaks. The level of long-term firm reservations is based on reservations that exist today and that have end

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[33] Energy Information Administration (EIA) Glossary, (http://www.eia.doe.gov/cneaf/electricity/page/glossary.html).
[34] FERC Order 888 Attachment D, the Pro Forma Tariff Terms and Conditions.

dates beyond the end of the test year. None of these reservations terminate prior to 2013. The results are reported in the Table 3-3.

Table 3-3

Transmission System Usage

Usage	Quantity (MW)
Long-term firm reservations	720
Forecasted average of network loads at the time of the 12 monthly system peaks in the fiscal year 2003/2004	2100
Total	**2820**

This information is used in the allocation of the transmission system revenue requirement.

3.2.5 Allocation of Revenue Requirements to Services

The last step in the cost allocation analysis is to allocate total transmission costs to the services that will be offered under the tariff. As noted above, these are point-to-point service, network service and the Scheduling, System Control and Dispatch Service.

The transmission revenue requirement for point-to-point and network services has been determined in Section 3.2.3 as $84.4 million/year. The transmission provider also collects revenues for the provision of services in addition to long-term firm services. These include short-term firm and non-firm point-to-point services, a grandfathered wheeling contact that pre-dates open access, and power factor penalties.

A projection of these revenues is subtracted from the gross revenue requirement prior to the allocations to point-to-point and network service. The projection of this miscellaneous revenue is $8.1 million. Therefore, the revenue requirement for allocation is adjusted to $76.3 million.

This revenue requirement is allocated to the different transmission services based on their load ratio share of the system. Applying 720 MW for point-to-point reservations and 2100 MW for network service the allocation of costs to these services is shown in Table 3-4.

Table 3-4
Transmission Services Revenue Requirements

Service	Usage (MW)	Share	Revenue Requirement ($ millions)
Point-to-Point	720	25.53%	19.47
Network	2100	74.47%	56.80
Total	2820	100.0%	76.27

The revenue requirement for each service can also be expressed on a per unit of usage basis as shown in Table 3-5. Because the allocation of the transmission revenue requirement to point-to-point and network service was done on the basis of the respective usage the cost per unit of service is the same for each. The $/kW-yr figures given represent the per unit cost of providing each of the services based on the application of the transmission pricing principles.

Table 3-5
Per Unit Transmission Services Revenue Requirements

Service	Revenue Requirement ($ millions)	Usage (MW)	Per Unit Revenue Requirement ($/kW-yr)
Point-to-Point	19.47	720	27.04
Network	56.80	2100	27.04
Total	76.27	2820	27.04

3.3 Rate Design

Now that costs have been allocated to specific services it is possible to design rates to recover these costs. This is essentially the third step referenced in the first pricing principle of FERC under which the transmission provider can recover its revenue requirement. This design of rates involves the following:

- Selection of a rate structure
- Selection of billing determinants for each service
- Determination of rates using the billing determinants to collect the revenue requirements

All of the information determined previously from the Total Revenue Requirement and the Cost Allocation Analysis is considered.

3.3.1 Postage Stamp Rate Structure

A postage stamp rate 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 destination. Although the most common approach in North America has been to use postage stamp rates, alternative transmission service pricing structures have been identified and used in some jurisdictions.

The alternatives to a postage stamp rate include location based (zonal or nodal) pricing, flow-based rates, and distance based rates. NB Power's current approach is a postage stamp rate that is the structure applied in the FERC Order 888 *Pro Forma Tariff*. This approach was also adopted in Saskatchewan, Manitoba, and Quebec. British Columbia, Alberta and Ontario have opted for zonal rate approaches. Most U.S. utilities have implemented the *Pro Forma* postage stamp approach but there are cases where locational-based marginal pricing, (Pennsylvania, New Jersey, Maryland Interconnection), zonal (New York Power Pool), flow gate (Midwest Independent System Operator) and distance based (Mid Area Power Pool, Maine Electric Power Company) have been approved by FERC. The decision to deviate from the postage stamp approach in these areas has been influenced by the structural nature of those systems and the markets that they serve. Systems with tightly meshed transmission networks like New Brunswick have generally all adopted the postage stamp approach.

To a large extent, the characteristics of the wholesale market will determine the ability of a transmission tariff design to promote efficient use of assets. For example, in the presence of persistent congestion it can be advantageous to use location-based pricing. Increased transmission costs across a congested interface will discourage such transactions thereby tending to alleviate the congestion. In markets where congestion is not significant, such as inside New Brunswick, there is little value in adopting a locational-based marginal pricing structure.

Additional analysis of postage stamp rates suggest that the transmission service revenue requirement must be based on shared assets that benefit multiple users in terms of efficient and reliable transmission service. It is not appropriate for the revenue requirement to include assets that are only useful for particular customers or customer classes (e.g. generation related transmission assets). Incorporating such single purpose assets into transmission rates disregards both the "cost causation" and the "used and useful" principles. This pitfall is avoided in the proposed tariff by assigning the cost of these single-purpose GRTAs to the specific users rather than including them in the transmission service revenue requirement.

The adoption of a postage stamp rate approach means that transmission customers will continue to pay the same rate for transmission service regardless of the point of delivery. This approach is consistent with the historical NB Power rate structure in that the rates are not a function of the location of the load. This consistency respects the principle of the *Energy Policy White Paper* that states that *"…the Province will entitle customers that do not select a competitive supplier to offer standard offer service under regulated prices and terms that are consistent with the service they now obtain."*[35] A transmission tariff that differentiates between different regions with respect to the recovery of the embedded cost of the grid would not be compatible with this policy principle.

The New Brunswick system has little transmission congestion, a centralized System Operator, and a desire to minimize the costs and complexity of the implementation of a transmission tariff. Given these factors, and the aforementioned discussion, NB Power proposes a postage stamp rate as the most appropriate structure for the recovery of the embedded cost of NB Power's transmission system.

3.3.2 Definition of Billing Determinants

In order to determine the price that will be charged to users of a particular service the metric, also referred to as a billing determinant, must be defined. Some of the commonly used billing determinants in the electric power industry are customer charge, kW of demand, and kWh of energy.

In defining the billing determinant one must consider issues such as measurability, simplicity, and fairness. It has already been established in the discussion above on cost allocation that transmission costs should be allocated to users based on the committed

[35] *Energy Policy White Paper* (3.1.5.3 Standard Offer Service) p24.

capacity. In the case of long-term point-to-point customers, the reserved MWs define the committed capacity. Reserved quantity can readily be used as the billing determinant for point-to-point service. In the case of network customers committed capacity is more difficult to define but, as discussed in the cost allocation section, is a function of the 12 monthly coincident peak loads.

Energy delivered can be considered as a billing determinant for a network customer's transmission usage but this approach does not follow the principle of cost causation. A customer with a very low load factor (a low quantity of energy delivered relative to the peak demand) would pay very little for transmission even though the transmission system needs to be able to meet the customer's peak demand. Such an approach would clearly lead to cross subsidization for transmission services of low load factor customers by other customers.

Historically in-province customers of NB Power have been billed for the demand component of their purchased services based on their respective demand, not on the basis of their demand relative to the system peak. The existing metering fully supports such billing but does not fully support coincident peak billing as not all wholesale customers have interval meters that capture the hourly peak readings. Without the hourly peak readings there is no way to identify the individual customer's demand at the time of the system peak for the month.

In addition to the issue of adequate metering, there is an issue with respect to the potential for customers to anticipate the system peak for the month and to minimize their demand at that time. Although in general this type of load shifting is favorable, the benefits are not so significant if it only addresses the peak for the month. If the shifting ignores the fact that there are other days in the month when the bulk network is heavily loaded and the fact that the peak loading for the local area may be most heavily loaded at hours other than the hour of system peak, then the benefits of the shifting of demand are diminished.

Another aspect of billing for transmission relates to self-generating customers and is an issue of whether to bill on net demand or gross demand. The net demand is the measurement of the demand for power at the interface between the transmission system and the customer. The gross demand is the measure of total on-site electrical load of the customer in any given interval. Net demand is the gross on-site electrical load of the customer in any given interval less any on-site generation in that interval. If the customer has no on-site generation then the net demand equals the gross demand.

This issue of net versus gross demand is also related to the issue of coincident versus non-coincident billing. A self-generator that can exercise control over the net demand at the time of system peak through reliable generation or load control would incur less cost for transmission under coincident net demand billing than under non-coincident net demand billing. Combining coincident billing with net demand billing would provide a substantial opportunity for self-generating customers to pay less. At the other extreme, combining non-coincident peak billing with gross demand billing would lead to the self-generating customer paying more.

FERC Order 888 and subsequent jurisprudence clearly state that self-generating customers must be provided with the option to choose between point-to-point service and network service.[36] If point-to-point service is chosen, the customer can reserve the transmission capacity that it requires. Transmission customers whose usage exceeds their reservation will be treated in accordance with the terms and conditions of the tariff. In many cases the treatment reflects a penalty for the use of unreserved transmission. The customer also faces the possibility of interruption or curtailment in the case of a transmission constraint. In the FERC *Pro Forma,* if the customer chooses network service the billing determinant is the load ratio share based on the gross demand at the time of system peak, not the net demand. However, some utilities with self-generation have modified this to include only a percentage of the self-generation component of the load as a means of reaching a negotiated settlement of this issue.

[36] FERC Docket Nos. RM95-8-001 and RM94-7-002, pp. 241-251

Canadian Utilities implementing tariffs have tended to adhere to the FERC *Pro Forma* by billing for network service on the basis of coincident demand on gross load. It is worth noting that in these jurisdictions they have gone to the minimum Order 888 requirement of wholesale access but not to transmission level retail access as is being done in New Brunswick based on the *Energy Policy White Paper*.

In the New Brunswick context there are additional considerations. The existing self-generating customers (and other industrial customers that purchase non-firm products) currently pay no demand charge for the portion of their load that they can meet with their own generation or reduce at the request of the System Operator. Also the *Energy Policy White Paper* directs that existing and new self-generators be treated the same.[37] The Market Design Committee was concerned that the charges for transmission could result in substantial rate increases for existing users of non-firm products. This consideration made the committee reluctant to see gross demand as the billing determinant for network service. Although some members felt that there should continue to be no demand rates for non-firm transmission, there was consensus that under such an approach customers using non-firm products would not be paying a fair share of the transmission system costs, leaving these costs to be carried by other customers. The Market Design Committee also discussed the fact that under an Order 888 type tariff many of the self-generation customers could offset the costs of ancillary services costs through self-supply. The Market Design Committee also discussed that in the new market rules self-generators would be permitted to sell ancillary services and further mitigate any new costs that might result from the introduction of the Tariff. The Market Design Committee considered the aforementioned issues and produced recommendations to bill on non-coincident net demand by delivery point.[38]

[37] Energy Policy White Paper (3.1.4.2 Self-Generation).
[38] Market Design Committee, Final Report (April 2002) 6.4.3 (Recommendations 6-70 and 6-71, p54).

Based on all the factors discussed in this section net non-coincident demand by delivery point has been selected as the billing determinant for use in the NB Power Tariff design for network service. Reserved capacity has been selected as the billing determinant for point-to-point service. The Market Design Committee also addressed the *Energy Policy White Paper* directive to examine means by which rate shock to existing self-generators can be avoided.[39] The result was a recommendation that the Tariff to be implemented by NB Power should attempt to mitigate potential rate shock to existing self-generators.[40] Rate shock is partially addressed in the Tariff where self generators have the opportunity to self-supply ancillaries. It is also anticipated that they will have the opportunity to sell any excess to the System Operator under new market rules.

Additional rate shock mitigation for self-generators can be addressed through the provision of an opportunity for a transmission customer to take network service to reduce its transmission costs by reducing its net non-coincident demand in the on-peak hours. Customers, including those that currently purchase non-firm products, could have the opportunity to shift load from on-peak hours to off-peak hours. Such a shift is consistent with overall energy efficiency goals and as proposed in the Tariff. This shifting would also potentially reduce the cost of the shared transmission assets by reducing the on-peak loading. Therefore such an economic signal is appropriate.

For network service, on-peak hours are defined as the time between the hour ending 08:00 and hour ending 23:00 Atlantic Time, Monday to Friday, except statutory holidays in New Brunswick. This shifting of demand is encouraged by considering only 71% of the net monthly non-coincident peak demand in the off-peak hours when the peak monthly demand for each customer is evaluated. Under this approach the greater of the following two demands is used as the billing determinant:

- net monthly non-coincident peak demand in the on-peak hours
- 71% of the net monthly non-coincident peak demand in the off-peak hours

[39] Energy Policy White Paper (3.1.4.2).
[40] Market Design Committee Final Report (April 2002) 6.4.2 (Recommendation 6-69, p53).

3.3.3 Determination of Rates

Given that the revenue requirement and billing determinants have been defined for each service the nominal rate is merely the revenue requirement for the service divided by the respective billing determinant. Table 3-6 illustrates the calculation of the nominal annual rate for each service.

Table 3-6
Determination of Nominal Rates by Service

Services	Revenue Requirement ($millions/yr)	Billing Determinant (kW)	Nominal Rate ($/kW/yr)
Point-to-Point Services			
Transmission	19.47	720,000	27.0
Schd, Control & Dispatch	1.030		1.43
Network Services			
Transmission	56.80	2,571,000	22.1
Schd, Control & Dispatch	3.005		1.16

For transmission service it is a common industry practice in North America to apply what is frequently referred to as Appalachian pricing. In Appalachian pricing the short term services are priced higher for an equivalent time period. This concept has been approved by FERC[41] and is used in Manitoba and Saskatchewan. This approach with minor modifications has also been applied in Quebec subject to the April 2002 decision of the Quebec regulator, the Régie de l’énergie.

[41] Appalachian Power Company, 39 FERC 61,296 (1986) and NY State Electric and Gas Company, 92 FERC 61,169 (August 17, 2000).

The Appalachian pricing approach applied by NB Power is consistent with FERC requirements and defines various short term rates as a fraction of the yearly rate as follows:

Yearly	=	nominal rate
Monthly rate	=	Yearly rate / 12
Weekly rate	=	Yearly rate / 52
On-Peak Daily rate	=	Weekly rate / 5
Off-Peak Daily rate	=	Yearly rate / 365
On-Peak Hourly rate	=	On-Peak Daily rate / 16
Off-Peak Hourly rate	=	Yearly rate / 8760

The rationale behind the On-Peak Daily and Hourly rates is that there is a difference between short-term services used for meeting peak load and those that are taking advantage of economically profitable opportunities. On-Peak hours for point-to-point service are defined by NB Power as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday. These types of transactions tend to occur on-peak and therefore in order to fully recover the appropriate revenue requirement these services are often priced with the On-Peak Daily rate at the weekly rate divided by 5 and the On-Peak Hourly rate is the On-Peak Daily rate divided by 16.

NB Power has chosen to propose rates based on the calculations shown above. This approach helps ensure adequate collection of revenues for services provided, while facilitating the use of the transmission capacity in the off-peak hours.

Based on the overall revenue requirement defined, the application of the cost allocation analysis, and the design of the end use rates just described, the rates proposed by NB Power for acceptance by the PUB are detailed in Table 3-7.

Table 3-7
Summary of Transmission Service Rates

Services	Units	Transmission Service	Scheduling, System Control & Dispatch
Yearly	$/kW-yr	27.04356	1.43052
Monthly	$/kW-m	2.25363	0.11921
Weekly	$/kW-w	0.52007	0.02751
On-Peak Daily	$/kW-d	0.10401	0.00550
Off-Peak Daily	$/kW-d	0.07409	0.00392
On-Peak Hourly	$/kW-h	0.00650	0.00034
Off-Peak Hourly	$/kW-h	0.00309	0.00016
Network	$/kW-m	1.84	0.10

3.3.4 Power Factor Penalty in the Transmission Tariff

The tariff includes a power factor penalty that will be applied for any month in which a transmission customer taking network service has a power factor of less than 90%. Under the tariff proposal the penalty paid per kVA (based on 90% of the metered kVA) that is in excess of the kW demand is 4 times the wires tariff (not to include any ancillary services) which is $7.36 (4 times $1.84). This policy applies to all customers directly connected to the transmission system.

This policy is consistent with the current NB Power policy with respect to large industrial customers. Under the current rates for large industrial customers the penalty paid per kVA (based on 90% of the metered kVA) that is in excess of the kW demand is $9.41 per month.[42] This policy also gives a new option to the Municipal customers. Under current rates Municipal customers are required to maintain an acceptable power factor. Under the proposed tariff Municipal customers will have the option to pay a power factor penalty to amend for poor power factor performance rather than being strictly obligated to make corrections to their power factor.

This approach gives large industrial customers the same flexibility that they have under current bundled rates. Also without this power factor penalty the transmission provider would not have the same tools that NB Power has today to encourage acceptable power factors. Rather than treat different classes of customers differently, the policy has been extended to directly connected customers other than large industrial customers that choose network service.

Based on the test year metering data the anticipated revenue from power factor penalties is $880,000 per year. This anticipated revenue is subtracted from the gross revenue requirement as part of the revenue requirement allocation process as noted in Section 3.2.5 of this document.

4.0 ANCILLARY SERVICES COST OF SERVICE AND RATE DESIGN

Ancillary services are the support services that are required to enable the transmission system to transmit energy. They range from the actions necessary to effect and balance a transfer of electricity between buyer and seller to services that are necessary to maintain the integrity of the transmission system and enable it to be operated reliably.

This section addresses the development of rates for all of the ancillary services that are provided from generators under the control of the System Operators at the Energy Control Centre. Scheduling, System Control, and Dispatch Service is an ancillary service supplied directly by the transmission provider and is discussed in Section 3. The services provided from generators can be grouped into two main categories. Capacity-based

[42] The large industrial rate is $9.41 per kW of the billing demand per month and the billing demand is the greater of a number of possible demands, one of which is “90% of the maximum kVA demand”.

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 the generator capacity for provision of the service.

4.1 Capacity-Based Ancillary Services

The capacity based services are defined and provided in the tariff consistent with the numbered schedules used in the FERC *Pro Forma Tariff*. Some, however, are further unbundled into component services as follows:

- Regulation and Frequency Response from Generation Sources Service [Schedule 3 in tariff], composed of
  - Regulation; and
  - Load Following
- Operating Reserves – Spinning Reserve Service [Schedule 5 in tariff]
- Operating Reserves – Supplemental Reserve Service [Schedule 6 in tariff], composed of
  - Supplemental (10-minute); and
  - Supplemental (30-minute)

The revenue requirement for the capacity based services [Schedules 3, 5 and 6] is determined by multiplying the per unit cost of new proxy unit capacity for each service by the amount of capacity required to deliver the service. Proxy units are used rather than the embedded cost of NB Power generation because they produce a more appropriate price for the services. Once the revenue requirement is determined it is allocated to services and rates are set in a manner similar to that used for transmission services in Section 3 of this report.

4.1.1 The Choice of Proxy Units

The two key guiding principles in the selection of proxy units were the technical capability of a facility to provide a service and the simplicity of the modeling. A proxy price would not be meaningful if the proxy unit could not reasonably be argued to be the type of facility that would be built to provide the service. On the other hand, there would be little benefit to a complex model that simulated a fleet of resources to exactly meet the required quantity of resources. The approach taken was to use the costs of a reasonable proxy facility to determine the cost per unit of service provided. That unit cost was then multiplied by the required quantity to calculate the revenue requirement for the total actual quantity of the service that is to be provided under the tariff.

Regulation, Load Following, and Operating Reserve-Spinning are referred to as on-line capacity based services because they can only be provided by resources that are operating and connected to the system. A 400 MW combined cycle gas generation plant was selected as the proxy unit for the on-line ancillary services. The 400 MW configuration provides reasonable economies of scale and is a technically proven sizing. Such a unit could be on-line producing energy with some of its capacity and providing on-line capacity based ancillary services with the remainder. Also the general assumption within the energy industry is that most new generation for the production of energy in the foreseeable future will be combined cycle gas turbine. The combined cycle plant has a lower capital cost per kW of capacity than other types of generation with the technical capability to provide these on-line services.

Operating Reserve-Supplemental Reserve Services are referred to as off-line capacity based services because the resources that provide these services are not required to be operating and connected to the system. For off-line capacity based ancillary services (Operating Reserve-Supplemental Reserve Service Schedule 6 in the tariff) a 100 MW simple cycle gas turbine was used as the proxy. Such a unit could be sitting off-line most of the time and providing its full capacity as off-line ancillary services (Supplemental

Reserves). Its low capital costs make this type of unit more economical to provide the off-line reserve services than a combined cycle installation. Other types of generation with the technical capability to provide these services have higher capital costs. Note that there is a small additional cost for 10-minute reserve to account for the increased OM&A and capital costs associated with rapid start-ups.

The costs for the proxy unit to provide the capacity based ancillary services are based on previous estimates established by NB Power. They are summarized in Schedule 1.0 of Attachment B. The fixed costs of capital identify the ongoing revenue requirement associated with the initial capital investment. The fixed costs of capital are based on the transmission business unit's weighted-average cost of capital established in the financial report of this filing and an estimate of inflation. The OM&A cost reflects the ongoing operations and maintenance costs for such units. The payments in lieu of taxes reflect the taxes that would be paid on the corporate income associated with the equity portion of the financing of the assets.

4.1.2 Requirements of Capacity Based Services

As the Operator of the Maritimes Control Area, the transmission provider has a responsibility to operate in accordance with NERC and Northeast Power Coordinating Council (NPCC) criteria. This includes the responsibility to determine the need for and to procure sufficient ancillary resources to reliably operate the electrical power network.

Additionally, the NB Power Tariff obligates the transmission provider to make all ancillary services available to all transmission customers. Therefore, the transmission provider must procure adequate generation resources to do so.

Transmission customers can purchase each of the ancillary services from the transmission provider whether they are taking point-to-point or network service. Therefore, the ancillary services are priced for both services. Transmission customers can self-supply the capacity-based ancillary services, or purchase them from either the transmission provider or a third party. In fact, when a load is located outside of the Control Area, it may be technically infeasible for the customer to buy these services from New Brunswick even though the customer is supplied by power that is delivered across the NB Power transmission system. The costs of these capacity-based services are allocated on a load share ratio between NB Power loads and outside loads that are currently using these services. The NB Power system requirements for "Regulation and Frequency Response" and "Operating Reserves" are outlined below.

Regulation and Frequency Response

The total system requirements represent the total average requirements to run the New Brunswick system and are based on the actual numbers for the NB system. The determination of the amount of this service, composed of both regulation and load following, required for the NB system has been calculated using empirical methods. The method can be described as follows. The total system load is broken into two components, a slowly varying trend which represents load following and a random higher frequency component with zero mean which represents regulation.

19 MW of regulation and 53 MW of load following is required for the NB system. Given that external customers carry a load ratio share obligation, the Tariff's obligation is 16.76 MW of regulation and 46.74 MW of load following. This includes the responsibility to cover tie line variations for other utilities in the Maritimes but does not include the load in Nova Scotia. The details are in Schedule 1.2 of Attachment B.

Operating Reserves

The requirement within the tariff for operating reserves is a function of reliability criteria established by the Northeast Power Coordinating Council (NPCC). The quantity of each type of reserve will depend on both the size of the contingencies and the load being served.

Since the Maritimes Control Area is not operated as a single entity, each utility has been responsible for carrying its own reserve requirements. NPCC requires that each Control Area maintain sufficient Contingency Reserve (10-Minute Spinning and 10-Minute Supplemental)[43] to cover 100% of the largest single contingency and 30-Minute Reserve to cover 50% of the second largest contingency.

The transmission customers' reserve obligation for each of the reserve services under this tariff will be based on their load share ratio. However, it will not exceed the obligations for the respective services that would exist if the 1^{st} and 2^{nd} contingencies were 10% of the annual peak load for the Control Area. The portion of the 1^{st} contingency in excess of 10% of the annual peak load (i.e. 5000 MW) for the Control Area (i.e. Maritimes Control Area) shall be the direct responsibility of the owner of the 1^{st} contingency. Similarly, the owner of the 2^{nd} contingency will be responsible for supplying the operating reserve capacity that is the direct result of the 2^{nd} contingency being in excess of 10% of the annual peak load.[44] Therefore the 1^{st} and 2^{nd} contingencies to be addressed by the load-serving entities within the Maritimes Control Area are 500 MW and 458.1 MW respectively.

Operating Reserve sharing arrangements have been made with NS Power, Maritime Electric, and Northern Maine. NS Power provides 125 MW of Contingency Reserve for the first contingency, of which 25% (31.25 MW) is spinning and 75% (93.75 MW) is Supplemental. NS Power also provides 50 MW of 30-Minute Reserve (i.e. the second contingency). Maritime Electric, Northern Maine and NB Power assume their load ratio share of the remaining obligation. Of this, NB Power's obligations are 88.2 MW of 10-Minute Spinning and 242.5 MW of 10-Minute Non-spinning, as well as 157.9 MW of 30-minute Reserve. The details are contained in Schedule 1.2 of Attachment B.

[43] A minimum of 25% of the 10-minute reserves must be spinning.

[44] The selection of 10% of the annual peak load is based on an historical rule-of-thumb used to determine the maximum size of a single generator for a specific system. Therefore, to the extent that a generator exceeds the 10% criteria, it must arrange for (supply, purchase or otherwise self-provide) the

4.1.3 Summary of Revenue Requirements for Capacity Based Services

The total revenue requirement for each service is the product of the quantity required multiplied by the cost per unit of service supplied as shown in Table 4-1.

Table 4-1
Revenue Requirement of Capacity Based Services

Services	Revenue Requirement ($/kW-yr)	Services Required (MW)	Revenue Requirement ($1000/yr)
Regulation	81.99	16.76	1,374
Load Following	67.87	46.74	3,172
Spinning (10-minute)	60.95	88.20	5,376
Supplemental (10-minute)	57.81	242.5	14,020
Supplemental (30-minute)	56.61	157.9	8,939

4.1.4 Capacity Based Service Rates

The annual cost of providing each service as a function of the usage is determined by dividing the total cost of providing the service by the usage of the respective service. For monthly point-to-point service and network service the annual cost of providing each service on a $/kW basis is divided by 12 to determine the monthly rate. Point-to-point customers purchasing the ancillary services on a yearly, or monthly service, as well as network service, are billed at the monthly rate at the end of each calendar month as noted in the terms and conditions of the tariff. The rate for weekly point-to-point services is 1/52nd of the annual rate and the daily rate is 1/5th of the weekly rate. Hourly

difference. This difference will be calculated annually and each generator's requirement will be rounded to the nearest 10 MW.

service is not available for the capacity based ancillary services due to the additional administrative burden of tracking how various point-to-point customers are fulfilling their obligations on an hourly basis. If hourly service were provided for the capacity based ancillary services there would be a potential impact on reliability should the policing of adequacy of reserves not be effective. The rates produced by this process are summarized in Table 4-2 and detailed in Attachment B.

Table 4-2
Nominal Rates For Capacity Based Ancillary Services

Service	Revenue Requirement ($1000/yr)	Usage (MW)	Rate $/kW-month
Regulation	1,374	2571	0.04
Load Following	3,172	2571	0.10
Contingency Reserve – Spinning	5,376	2571	0.17
Contingency Reserve – Supplemental (10-minute)	14,020	2571	0.45
Contingency Reserve – Supplemental (30-minute)	8,939	2571	0.29

4.1.5 Out-of-Order Dispatch

While the proxy unit pricing does place an appropriate value on the capacity that is used to provide capacity based ancillary services, it does not address the issue of out-of-order dispatch costs. Ignoring out of order dispatch costs would provide an opportunity for point-to-point customers using this service to purchase from the transmission provider when the market prices for energy are high, and to self-supply or purchase from a third party when the market prices for energy are low. It is often at these times that out-of-order dispatch costs are high. Paying out-of-order dispatch costs to the generator that is supplying the services to the transmission provider will help to ensure that the supplier of the service continues to receive adequate compensation and thereby ensure continued provision of the service.

The following are examples of scenarios in which out-of-order dispatch costs can occur.

> <u>Hydro unit spilling:</u> A hydro unit dispatched at less than its maximum current rating, while spilling water, in order to provide an ancillary service.

> <u>Hydro unit with low water and low market price:</u> A hydro unit is generating when its most economic dispatch would be to not run.

> <u>Hydro unit below its economic dispatch point:</u> A hydro unit is dispatched below its economic dispatch point in order to provide an ancillary service.

> <u>Thermal unit operating above its economic dispatch point:</u> A thermal unit is operating above its economic dispatch point.

> <u>Thermal unit operating because of the requirement for ancillary services:</u> A thermal unit is committed to run in order to fulfill the requirement for ancillary services.

> <u>Thermal unit operating below its economic dispatch point:</u> Thermal unit dispatched below its economic dispatch point in order to meet the needs of the transmission provider.

Determination of out-of-order dispatch costs requires that commitment schedules with and without provision of ancillary services be compared. The following describes the process that will be used to determine the out-of-order dispatch costs.

- The transmission provider releases day ahead obligations for ancillary services
- Generators submit day ahead generation plans to meet hourly energy obligations

- Generators submit a second day ahead proposal to meet ancillary service requirements (this second plan may not differ from the energy only generation plan of step 2)
- Transmission provider assesses the resources available to provide the ancillary services and selects the lowest cost option. The transmission provider will have the following information in order to perform the evaluation of the least cost option:
    - the generation cost information (or bids in the case of a third party provider that prefers confidentiality)
    - an estimate of the market price
    - start-up costs as provided by the generator (or price in the case of a third party supplier that prefers confidentiality)

The transmission provider will collect these out-of-order costs, if and when they occur, from transmission customers that are purchasing these services and pass the related revenue collected back to the generation providers of the service. If any additional investments are made in order to avoid out-of-order dispatch they will be included as out-of-order dispatch costs, but only up to the level of the out-of-order dispatch costs that would otherwise have been attributable to ancillary services.

4.2 Non-Capacity Based Ancillary Services

The non-capacity based ancillary services are:

- Scheduling, System Control and Dispatch [Schedule 1 in tariff]
- Reactive Supply and Voltage Control Service [Schedule 2 in tariff]
- Energy Imbalance Service [Schedule 4 in tariff]

The three-step methodology for developing rates (outlined and used above) is also employed to determine rates for these services. Rates for Scheduling, System Control and Dispatch service are derived from the transmission revenue requirements in Section 3 of this report. The remaining two non-capacity based ancillary services are considered below.

4.2.1 Reactive Supply and Voltage Control Service

The pricing for Reactive Supply and Voltage Control [Schedule 2] is determined from the proxy unit costs of supplying it and the quantities required in a manner similar to capacity based ancillary services.

The proxy selected for this service is a set of three 110 MVAR synchronous condensers. A synchronous condenser most closely simulates the Reactive Supply and Voltage Control services provided by a synchronous generator. The ability to operate at either a 'leading' or a 'lagging' power factor and the inertia that a synchronous condenser has makes it a reasonable proxy from the point of view of technical capabilities.

The total system requirement for this service from generators on the system is based on the MVAR output of in-province generators at the time of system peak plus an additional MVAR capability held in reserve to ensure dynamic system security.

Whether they are purchasing point-to-point or network service, all transmission customers use this service. Therefore the revenue requirement, net of charges for this service as provided with short-term firm and non-firm point-to-point services, is allocated to the two types of use. This allocation is done on the same basis as the allocation of the revenue requirement associated with the transmission system. This allocation to point-to-point and network services is explained in Section 3.2 of this document. The respective usages are the long-term firm point-to-point reservations and an average of 12 monthly peak network loads coincident with the system peak.

The rate design is patterned after the design of the point-to-point and network services as explained in Section 3.3 of this document. The revenue requirement for this service for users of point-to-point service is divided by the long-term firm reservation quantity. The revenue requirement of this service for users of network service is divided by the average of the 12 monthly non-coincident peak net demands for network service. The Appalachian pricing approach is applied to this service in the same fashion as it is applied to the point-to-point transmission service. The Appalachian pricing approach is explained in Section 3.3. The end result of this process is that the rates for this service are as shown in the Table 4-3.

Table 4-3
Reactive Supply and Voltage Control Service Rates

Services	Units	Rate
Yearly	$/kW-yr	1.801
Monthly	$/kW-m	0.150
Weekly	$/kW-w	0.03463
On-Peak Daily	$/kW-d	0.00693
Off-Peak Daily	$/kW-d	0.00493
On-Peak Hourly	$/kW-h	0.00043
Off-Peak Hourly	$/kW-h	0.00021
Network	$/kW-m	0.12

4.2.2 Energy Imbalance

Energy imbalance is a service that has no predictable required quantity and the cost of providing the service fluctuates with the real time cost of producing energy. For these reasons this service is discussed separately from the other services and is also priced uniquely.

The difficulty of forecasting load, the difficulty of controlling generator output, and the potential incentives for arbitrage make energy imbalances inevitable. Energy imbalance has a significant potential for cost shifting between suppliers as the quantity of the service used can be very volatile and can be intentionally varied by suppliers if it is to their advantage.

Since the users can control the usage of the energy imbalance service, the use of average embedded cost pricing would provide a substantial opportunity for users to profit from the use of the service at the expense of other suppliers. There are two common approaches to this problem in the industry. In areas that have some form of spot market (e.g. hourly energy market in New England) the spot market price is used to settle the energy imbalance differences. Because the spot market price reflects the real-time value of energy, users of the energy imbalance service pay, and the suppliers are paid, at the value of the energy. In areas that do not have a spot market, there is a tendency to price the service such that the suppliers are well protected and the users are discouraged from using the service. Paying low rates to transmission customers for over-supply and high rates to transmission customers for under-supply is a common approach used to encourage transmission customers to balance their supply with the load that they are serving.

The challenge in designing this service is to find the appropriate balance between protecting the providers of balancing energy and allowing a degree of tolerance for imbalances in the market so as not to make participation in the market impractical.

The Market Design Committee recognized the need for this balance and identified the issue in the following two recommendations concerning procurement and provision of this service:

> *"The MDC recommends that the System Operator shall operate an energy imbalance service. The System Operator can procure energy imbalance service from market participants, buying at the lowest available price within operating*

constraints. The energy imbalance service shall be priced at a proxy value recognizing cost and could move towards market-based pricing. The purpose is to encourage development of an efficient and effective service".[45]

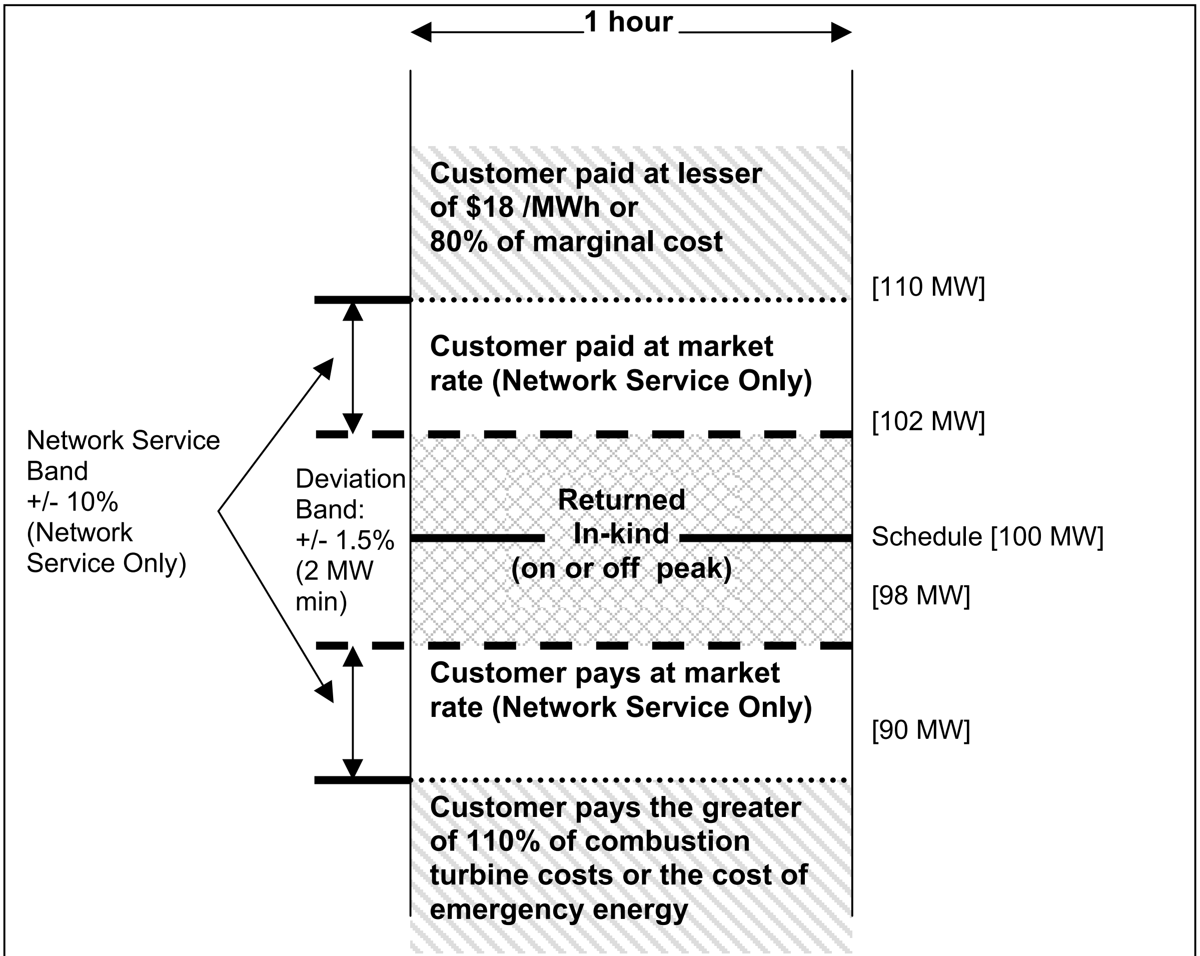
"The MDC recommends that balancing energy service be initially provided as an ancillary service through the transmission tariff and that its provision be based on the following principles:

- *It should efficiently provide economic signals that will drive behaviors appropriate for reliable operation of the system*
- *Pricing of the service should be market-based where possible through:*
    - *Offers for increments and decrements*
    - *A proxy market price*
    - *Ceilings and floors as necessary to protect participants".*[46]

Based on these considerations the energy imbalance service has been priced to encourage transmission customers to balance their supply to their load while permitting a reasonable degree of flexibility.

[45] Market Design Committee, Final Report (April 2002) Recommendation 3-29.
[46] Market Design Committee, Final Report (April 2002) Recommendation 3-30, p26.

Figure 4-1: Energy Imbalance Schematic



Note: Cumulative energy imbalance is limited to no more than +/- 20% of the average scheduled energy. Energy imbalances that occur while cumulative energy imbalance is in excess of +/- 20% of the average scheduled energy will be treated as being outside of the deviation bands.

The transmission provider settles hourly imbalances between the energy supplied and the energy consumed as illustrated in Figure 4-1. The energy imbalance service is structured to allow hourly imbalance within a clearly defined deviation band (+/- 1.5%, 2 MW minimum) to be settled through intentional scheduling of correcting imbalances. Energy imbalance for point-to-point service outside of the deviation band is priced to discourage excessive imbalances. Energy imbalance for network service outside of the deviation band within the larger network service band is priced at market based prices. Outside these two bands, energy imbalance is priced to motivate the transmission customer to avoid excessive imbalances. To prevent a build-up of imbalances, there is also a limit of +/- 20% of the average scheduled energy on the cumulative imbalance within the respective deviation band. The intention is to minimize the cost shifting that would occur if the value of energy at the time that the correction is made is different than what it was when the initial imbalance occurred.

5.0 SUMMARY

A summary of the rates for all services determined in this report is provided in Table 5-1. For ease of comparison the rates for all services are provided in the common units of $/kW-month.

Table 5-1
Rates For Services in NB Power's Open Access Transmission Tariff

Services	Schedule in Tariff	$/kW-month
Scheduling, System Control, and Dispatch Service Point-to-Point Network	Schedule 1	 0.11921 0.10
Reactive Supply and Voltage Control Point-to-Point Network	Schedule 2	 0.15 0.12
Regulation	Schedule 3	0.04
Load Following	Schedule 3	0.10
Energy Imbalance Service	Schedule 4	N/A
Contingency Reserve – Spinning	Schedule 5	0.17
Contingency Reserve – Supplemental (10-minute)	Schedule 6	0.45
Contingency Reserve – Supplemental (30-minute)	Schedule 6	0.29
Point-to-Point Service	Schedule 7	2.25363
Network Integration Service	Attachment H	1.84

Attachments

A. Transmission Services Cost Allocation and Rate Design Analysis

B. Ancillary Services Cost of Service and Rate Design Analysis

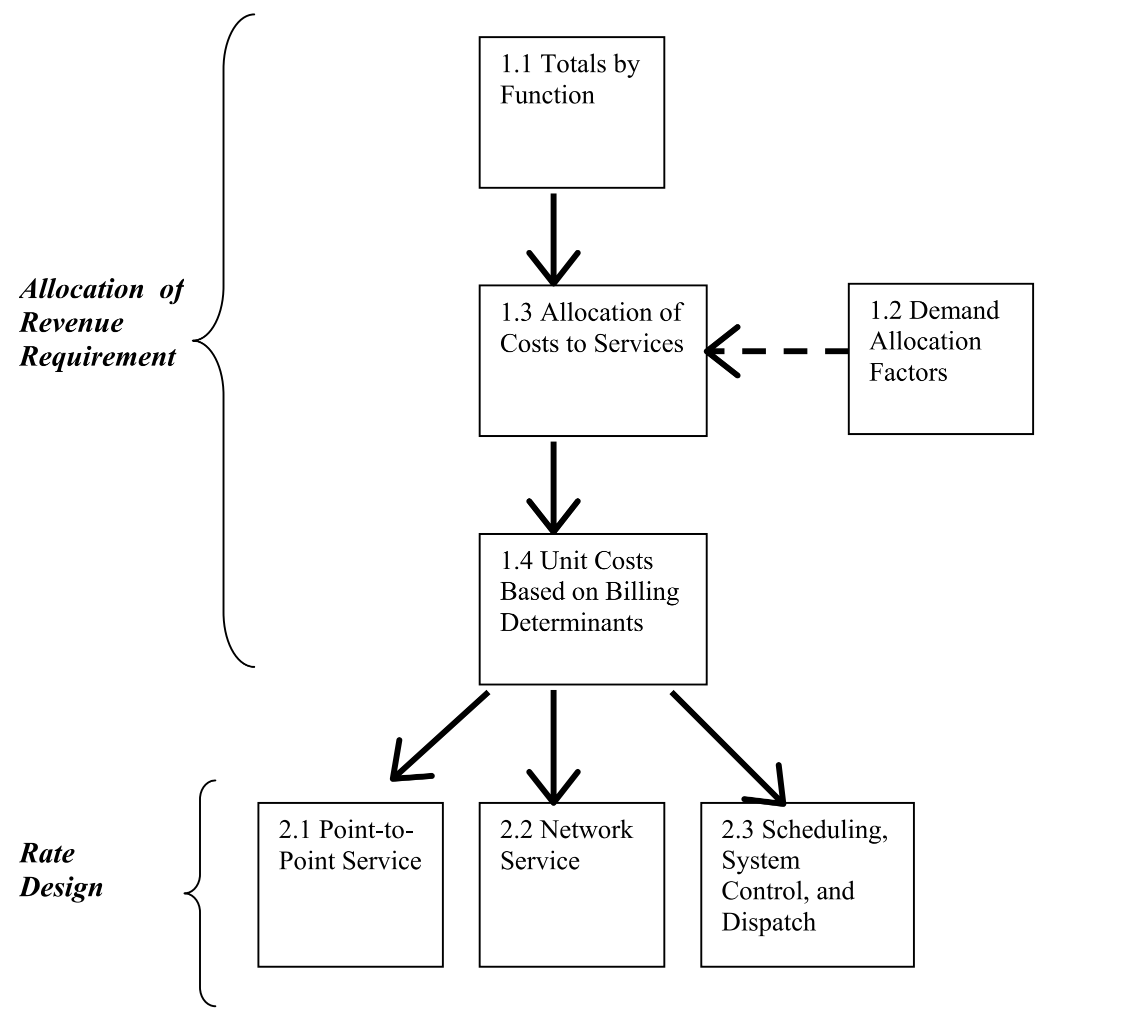
ATTACHMENT A: TRANSMISSION SERVICES COST ALLOCATION AND RATE DESIGN ANALYSIS

The Open Access Transmission Tariff Cost Allocation and Rate Design identifies and allocates the appropriate revenue requirement to the services provided under the tariff. The end-products are rate schedules for Point-to-Point Service, Network Service, and Scheduling, System Control, and Dispatch. This document outlines the contents and purpose of each of the seven schedules. The interrelationship between schedules is highlighted in Figure 1. The seven schedules are:

Schedule 1.1 Demand Allocation Factors
Schedule 1.2 Totals by Function
Schedule 1.3 Allocation of Costs to Service Category
Schedule 1.4 Unit Costs (Based on billing determinants)
Schedule 2.1 Rates for Point-to-Point Service
Schedule 2.2 Rate for Network Service
Schedule 2.3 Rate for Scheduling, System Control, and Dispatch

In Schedule 1.1 (Demand Allocation Factors), the load ratio share of demand is calculated for each service. This is used as the basis for allocations. Schedule 1.2 (Totals by Function) summarizes the costs associated with each asset category. Schedule 1.4 (Unit Costs) calculates the cost per unit of each service. The rates for each of the services provided directly by the transmission provider under the Open Access Transmission Tariff are presented in Schedules 2.1, 2.2, and 2.3.

Figure 1: Diagram of the Key Relationships between Schedules



NB POWER Transmission Business Unit
COST ALLOCATION
Totals by Function – Fiscal Year Ending March, 2004
($1000's)

Schedule 1.1

	1	2	3a	3b	4	5	6	7	8
Asset Category	**Average Gross Plant**	**Average Net Plant**	**Amortization Expense Total**	**Allocated Amortization Expense Total**	**OM&A Expense Total**	**Finance, Taxes & Return on Equity Total**	**Total Cost by Function**	**Credits by Function**	**Net Cost by Function**
Generation Related Transmission Assets	**65,375**	**38,872**	**2,101**	**2,524**	**1,577**	**5,518**	**9,619**	**0**	**9,619**
Unit Transformers	40,796	25,067	1,325	1,589	-	3,547	5,137	0	5,137
Terminals	10,340	4,609	300	367	713	675	1,755	0	1,755
Transmission Lines	14,239	9,197	476	568	864	1,296	2,728	0	2,728
Bulk Network	**469,060**	**233,536**	**11,477**	**14,403**	**29,956**	**33,749**	**78,109**	**7,522**	**70,587**
Interconnections									
Terminals	6,540	2,239	186	199	451	340	990	456	534
Transmission Lines	19,540	9,025	376	471	1,186	1,315	2,972	272	2,699
HVDC	32,735	5,928	261	473	1,784	1,021	3,278	300	2,978
In-Province									
Terminals	198,152	97,252	6,448	7,717	13,664	14,077	35,458	3,249	32,209
Transmission Lines	212,094	119,092	4,206	5,543	12,871	16,997	35,411	3,245	32,166
Local Service	**41,393**	**17,829**	**1,024**	**1,266**	**2,376**	**2,620**	**6,262**	**574**	**5,689**
Terminals	0	0	0	0	0	0	0	0	0
Metering	2,234	957	65	80	128	141	349	32	317
Transmission Lines	27,148	11,755	663	820	1,559	1,727	4,105	376	3,729
Specific Transmission Lines									
Industrial Customers	11,900	5,052	292	362	683	744	1,789	164	1,626
Wholesale Customers	111	65	3	4	6	9	20	2	18
Energy Control Centre (Transmission)	**11,254**	**3,294**	**152**	**225**	**3,634**	**512**	**4,371**	**337**	**4,035**
General Transmission Assets	**62,271**	**35,877**	**3,664**						
Total NB Power Transmission Business Unit	**649,352**	**329,408**	**18,418**	**18,418**	**37,544**	**42,400**	**98,362**	**8,432**	**89,930**

Basis of Allocation				Gross Plant	Assigned & Gross Plant	Net Plant	Col 3b + Col 4 + Col 5	Assigned & Col 6	Col 6 - Col 7

Notes:

General Transmission Assets consist of Telecom, Motor Vehicles, Work in Progress, and Other (including an allocation of Corporate)

Schedule 1.2

COST ALLOCATION

Demand Allocation Factors
Average of 12 Monthly Peaks

Service	1 Long-Term Firm Res'ns	2 Trans -mission System 12 CP	3 Allocation Factors (%)	4 Billing Determinants Substation 12 NCP Served at Distribution Transformer
Point to Point[(1)]	720	-	25.53%	0
Network In-Province	-	2,100	74.47%	2,571
TOTAL MW	720	2,100	100.00%	

Basis of Allocation	Col 1&2/ Total

Notes:

1 - Long-term firm reservations are reservation of at least one year in duration
2 - The allocation factors and billing determinants above are used in subsequent schedules

Schedule 1.3

NB POWER Transmission Business Unit

COST ALLOCATION

Allocation of Costs to Services
($1,000's)

Services	Amortization Expense: Bulk Network	Amortization Expense: Local Service	Amortization Expense: Generation Related Assets	Total	OM&A Expense: Bulk Network	OM&A Expense: Local Service	OM&A Expense: Generation Related Assets	Total	Finance Charges: Bulk Network	Finance Charges: Local Service	Finance Charges: Generation Related Assets	Total	Credits: Total	Total
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Point-to-Point Service	3,677	323	0	4,000	7,647	607	0	8,254	8,615	669	0	9,284	2,067	19,471
Network Service (2)	10,726	942	0	11,669	22,309	1,770	0	24,079	25,134	1,952	0	27,085	6,029	56,804
Generation Connection Service	0	0	2,524	2,524	0	0	1,577	1,577	0	0	5,518	5,518	0	9,619
Scheduling, System Control, and Dispatch				225				3,634				512	337	4,035
Total NB Power Transmission Business Unit	14,403	1,266	2,524	18,418	29,956	2,376	1,577	37,544	33,749	2,620	5,518	42,400	8,432	89,930
Basis of Allocation	Sch 1.2 Col 3	Sch 1.2 Col 3	Assigned	Col 1 + Col 2 + Col 3	Sch 1.2 Col 3	Sch 1.2 Col 3	Assigned	Col 5 + Col 6 + Col 7	Sch 1.2 Col 3	Sch 1.2 Col 3	Assigned	Col 9 + Col 10 + Col 11	Assigned	Col 4 + Col 8 + Col 12 - Col 13

Notes:
1. The total expense associated with each function (bulk network, local service, generation related transmission assets) comes from Column 8 of Schedule 1.1 Cost Allocation
2. The allocation of the revenue requirement associated with each function is identified above.

Schedule 1.4

NB POWER Transmission Business Unit

COST ALLOCATION

Unit Costs

Services	1 Total Cost By Service ($1000)	2 Total Usage By Service (MW)	3 $/kW-yr	4 Monthly $/kW-m
Point-to-Point Service[1]	19,471	720	27.04	2.25
Network Service[2]	56,804	2,100	27.04	2.25
Sub-Total Point-to-Point and Network Service	**76,276**	**2,820**	**27.04**	**2.25**
Generation Connection Service	9,619	N/A	N/A	N/A
Scheduling, System Control, and Dispatch	4,035	2,820	1.43	0.12
Total NB Power Transmission Business Unit	**89,930**	**N/A**	**N/A**	**N/A**
Basis of Allocation	Sch 1.3 Col 14	Sch 1.2 Cols 1&2	Col 1 / Col 2	Col 3 / 12

Notes:

1 - Usage based on firm reservations
2 - Usage based on substation 12NCP for 2003/2004
3 - Cost of service = cost by service / usage by service

Schedule 2.1

NB POWER Transmission Business Unit

RATE DESIGN

Rates for Point-to-Point Services

	1	2	3	4
Service Category	Total Cost By Class ($1000)	Total Usage By Class (MW)	$/kW-yr	$/kW-m
Point-to-Point Service(1)	19,471	720	27.04351	2.25363

			Rates $/MW-yr	Rates $/MW-m
Yearly(2)		Monthly Cost * 1000	27,043.56	2,253.63
Monthly(3)	($/MW-m)	Yearly/12		2,253.63
Weekly(3)	($/MW-w)	Yearly/52		520.07
On-Peak Daily(3)	($/MW-d)	Weekly/5		104.01
Off-Peak Daily(3)	($/MW-d)	Yearly/365		74.09
On-Peak Hourly(4)	($/MW-h)	Daily/16		6.50
Off-Peak Hourly(4)	($/MW-h)	Yearly/8760		3.09

Notes:

1 - Usage based on long term firm reservations
2 - Firm only
3 - Firm or non-firm
4 - Non-firm only

NB POWER Transmission Business Unit

RATE DESIGN

Rate for Network Service

	1	2	3	4
Service Category	**Cost of Service $/kW-yr**	**Cost of Service Monthly $/kW-m**	**Coincidence Factor**	**Monthly $/kW-m Billing Rate**
Network Service	**27.04**	**2.25**	**81.7%**	**1.84**
Basis of allocation	Sch 1.4, Col 3	Col 1/12	See Note Below	Col 2 * Col 3

Notes:

Calculation of coincidence factor for network service loads

a 12 coincident peak load	2,100	MW	(Sch 1.2, Col 2)
b 12 non-coincident peak load	2,571	MW	(Sch 1.2, Col 4)
Coincidence factor = **a/b**	81.7%		

1

Schedule 2.3

NB POWER Transmission Business Unit

RATE DESIGN

Scheduling, System Control, and Dispatch (Schedule 1 of the Tariff)

	1	2	3	4
Service	**Total Cost of Service ($1000)**	**Total Usage (MW)**	**Yearly Cost $/kW-yr**	**Monthly Cost $/kW-m**
Sched, Sys. Ctrl. & Disp	**4,035**	**2,820**	**1.43048**	**0.11921**

Sched, Sys Ctrl. & Disp for Point-to-Point(1)		**Rate for Services Billed Monthly**		
		Services	**$/MW-yr**	**$/MW-m**
Yearly(2)		Monthly Cost * 1000	**1,430.52**	**119.21**
Monthly(3)	($/MW-m)	Yearly/12		**119.21**
Weekly(3)	($/MW-w)	Yearly/52		**27.51**
On-Peak Daily(3)	($/MW-d)	Weekly/5		**5.50**
Off-Peak Daily(3)	($/MW-d)	Yearly/365		**3.92**
On-Peak Hourly(4)	($/MW-h)	On-Peak Daily/16		**0.34**
Off-Peak Hourly(4)	($/MW-h)	Yearly/8760		**0.16**

	Cost of Service			**Rate**
	$/kW-yr	**$/kW-m**	**Coincidence Factor**	**Monthly $/kW-m**
Sched, Sys. Ctrl. & Disp. for Network Service	**1.43**	**0.12**	**81.7%**	**0.10**

Notes:

1 - Usage based on long term firm reservations
2 - Firm only
3 - Firm or non-firm
4 - Non-firm only

1

ATTACHMENT B: ANCILLARY SERVICES COST OF SERVICE AND RATE DESIGN ANALYSIS

Capacity Based Ancillary Services
Cost Data for Proxy Units

Parameters		Greenfield Combined Cycle Gas Unit	Simple Cycle Gas Unit
Variable OM&A Cost	($M)	2.1	0.2
Fixed OM&A Cost	($M)	11.8	0.5
Capital Additions	($M)	0.4	0.2
	($/kW-Yr)	1.0	1.6
Capital Cost	($M)	428	60
	($/kW)	1070	600
Project Life	(Years)	25	25
Capacity	(MW)	400	100
Year Dollars	2006		
Escalation Rate	1.80%		
Interest Rate	7.15%		
Levelized Lifecycle Costs			
Variable OM&A Cost	($/MWh)	0.88	0.88
Fixed OM&A Cost	($/kW-Yr)	34.63	5.87
Capital Additions	($/kW-Yr)	1.17	1.88
Capital Cost	($/kW-Yr)	93.06	52.18

Notes:
1. The combined cycle unit is used as the proxy for on-line services
2. The simple cycle unit is used as the proxy for off-line services

Capacity Based Ancillary Services
Cost of Providing Services

		1	2	3	4	5	6	7	8	9	10	11
Ancillary Service	**Proxy Source**	**Capacity (MW)**	**Capital Cost 2004$ ($/kW)**	**Exp'd Life (y)**	**Escallating Capital Charge ($/kW-yr)**	**O&M ($/kW-yr)**	**Payments in Lieu of Taxes ($/kW-yr)**	**Total Fixed Costs ($/kW-yr)**	**Contribution Reactive Supply ($/kW-yr)**	**Installed Capacity ($/kW-yr)**	**Energy Prod'n[3,4] ($/kW-yr)**	**Rate for Ancill. Service ($/kW-yr)**
Regulation and Frequency Response												
Regulation	Combined Cycle - Greenfield (Fast AGC)	400	$1,032	25	$101.42	$31.39	$22.36	$ 155.17	$1.21	$17.31	$54.66	$81.99
Load Following	Combined Cycle - Greenfield (Slow AGC)	400	$1,032	25	$101.42	$30.48	$22.36	$ 154.26	$1.21	$17.31	$67.87	$67.87
Operating Reserves												
Spinning (10 Minute)	Combined Cycle - Greenfield	400	$1,032	25	$101.42	$30.18	$22.36	$ 153.96	$1.21	$17.31	$74.50	$60.95
Supplemental (10 Minute)	Combustion Turbine - Simple Cycle (quickstart)	100	$ 589	25	$57.85	$5.11	$12.75	$ 75.72	$0.60	$17.31	$0.00	$57.81
Supplemental (30 Minute)	Combustion Turbine - Simple Cycle	100	$ 579	25	$56.87	$5.11	$12.54	$ 74.52	$0.60	$17.31	$0.00	$56.61

	Sch 1.0	Sch 1.0 in 2004$	Sch 1.0	Sch 1.0	Sch 1.0		Col (4+5+6)	MVAR/MW *React Cost Note 5 *React Cost $/kVAR/yr	Assign		Col 7 - Col 6 -Col 9 - Col 10

Notes:

1. ICAP value based on Natsource 12 month quotes for 2003 escallated to 2004 — Discount rate 10.3%
2. MVAR/MW 48.4% (90% lagging power factor requirement) — Escallation 1.8%
3. Capacity factor for regulation 40%
4. Capacity factor for load following 50%
5. Capacity factor for spinning reserve 55%
6. Capacity factor for supplemental 10 minute reserve 0%
7. Capacity factor for supplemental 30 minute reserve 0%

Capacity Based Ancillary Services
MW Requirements

	1	2	3	4	5	6
	Maritimes Control Area	Nova Scotia	NB/N.Me./ PEI	PEI	Northern Maine	New Brunswick
Peak Load (using 2001/2002 12CP)	3926	1598	-	156	119	2053
Maritimes Control Area Load Share Ratio	100.00%			3.97%	3.03%	52.29%
Without Nova Scotia			100.00%	6.70%	5.11%	88.19%
Regulation and Frequency Response						
Regulation			19	1.27	0.97	16.76
Load Following			53	3.55	2.71	46.74
Operating Reserves (Contingency Reserves)						
Spinning (10 Minute)	125.0	25.0	-	6.7	5.1	88.2
Supplemental (10 Minute)	375.0	100	-	18.4	14.1	242.5
Supplemental (30 Minute)	229.1	50	-	12.0	9.2	157.9
Nominal first contingency relative to Maritimes Control Area 1CP load			5000	MW	10%	500
Actual first contingency						660
Nominal second contingency relative to Maritimes Control Area load					10%	500
Actual second contingency						458.1

Notes:
1. The smaller of the nominal and actual contingencies will be the tariff obligation
2. The spinning reserve requirement is typically 25% of the total 10 minute reserve
3. The 10 minute reserve requirement is 100% of the largest contingency
4. The 30 minute reserve is 50% of the second largest contingency

Capacity Based Ancillary Services
New Brunswick Usage

	1	2	3	4	5
		Network Service Billing Determinants			
	Usage by Point-to-Point MW	Total MW	Loads That Self Supply MW	Loads That Purchase From Third Party MW	Net Usage in Tariff MW
Regulation and Frequency Response					
Regulation	0	2571	0	0	2571
Load Following	0	2571	0	0	2571
Operating Reserves (Contingency Reserves)					
Spinning (10 Minute)	0	2571	0	0	2571
Supplemental (10 Minute)	0	2571	0	0	2571
Supplemental (30 Minute)	0	2571	0	0	2571
					Col (1+2-3-4)

Notes:
1. Customers also have the option to self-supply or purchase these services from a third party

Capacity Based Ancillary Services
Rate Design
Revised Version

	1	2	3	4	5	6	6'	7	8
	Revenue Req't ($/kW-yr)	**Service Req'd (MW)**	**Revenue Req't ($1000/yr)**	**Usage (MW)**	**Rate for Pt-Pt ($/kW-yr)**	**Rate for Pt-Pt ($/MW-m)**	**Rate for Network ($/kW-m)**	**Rate for Pt-Pt ($/MW-w)**	**Rate for Pt-Pt ($/MW-d)**
Regulation and Frequency Response									
Regulation	$ 81.99	16.76	$ 1,373.82	2571	$ 0.534	$ 44.50	$ 0.04	$ 10.27	$ 2.05
Load Following	$ 67.87	46.74	$ 3,172.38	2571	$ 1.234	$ 102.83	$ 0.10	$ 23.73	$ 4.75
Operating Reserves (Contingency Reserves)									
Spinning (10 Min.)	$ 60.95	88.2	$ 5,375.08	2571	$ 2.090	$ 174.17	$ 0.17	$ 40.19	$ 8.04
Supp. (10 Min.)	$ 57.81	242.5	$ 14,020.66	2571	$ 5.450	$ 454.17	$ 0.45	$ 104.81	$ 20.96
Supp. (30 Min.)	$ 56.61	157.9	$ 8,939.43	2571	$ 3.480	$ 290.00	$ 0.29	$ 66.92	$ 13.38
Totals		552.1	$ 32,881.37		$ 12.790	$ 1,065.67	$ 1.05	$ 245.96	$ 49.19
	Sch 2.1	Sch 2.2	Col 1 * Col 2	Sch 2.3	Col 3/Col 4	Col 5/12 *1000	Col 6' Rounded /1000	Col 5/52	Col 7/5

Capacity Based Ancillary Services
External Revenues
Revised Version

	1	2	3	4
	Rate ($/kW-yr)	**PEI (MW)**	**N. Maine (MW)**	**Total**
12NCP (12CP, Schedule 1.2 * Coincidence factor)		191	146	337
Regulation and Frequency Response				
Regulation	$ 0.53	$ 102	$ 78	$ 180
Load Following	$ 1.23	$ 236	$ 180	$ 415
Operating Reserves (Contingency Reserves)				
Spinning (10 Minute)	$ 2.09	$ 399	$ 304	$ 703
Supplemental (10 Minute)	$ 5.45	$ 1,041	$ 794	$ 1,834
Supplemental (30 Minute)	$ 3.48	$ 664	$ 507	$ 1,171
Total ($1000/yr)				$ 4,304

Notes:
1. These services are itemized separately on the Transmission income statement
2. The coincidence factor is assumed to be 81.7% (12NCP data not available)
3. The actual revenues will depend upon the extent to which the external parties choose to either self-supply or purchase from a third party. The estimate of these external revenues for the test year is $300,000.

Schedule 2.1

Reactive Supply and Voltage Control
Service Cost

		1	2	3	4	5	6	7
Ancillary Service	**Proxy Source**	**Capacity (MVAr)**	**Capital Cost 2003$ ($)**	**Expected Life (y)**	**Escallating Capital Charge ($/yr)**	**O&M ($/yr)**	**Payments in Lieu of Taxes ($/kW-yr)**	**Total Fixed Costs ($/yr)**
Reactive Supply and Voltage Control								
	Synchronous Condensors[1]	330	$26.5	30	$2.48	$0.08	$0.90	$3.46
Adjustment to account for the fact that a synchronous generator is more economical because of the dual purposes served by the generator (energy production and reactive supply and voltage control)						50.0%		$ 1.73
Revenue requirement per VAR of capability				$/kVAR/yr				$5.25
Estimated peak VAR requirement				MVAR	246			
Additional VAR requirement for dynamic system security				MVAR	800			
	Total VAR requirement			MVAR	1046			1046
Revenue requirement total				$1000/yr				$ 5,488

Notes:

1. Based on historical costs escallated to 2003 dollars
2. Discount rate 10.3%
3. Escallation 1.8%
4. Note that the total nameplate capability of generation currently on the system is 2200 MVAR
5. The requirement divided by the nameplate capability is 1046 divided by 2360 47.5%

Reactive Supply and Voltage Control
Rate Design

	1	2	3	4	5	6	7	8	9
	Revenue Requirement ($1000/yr)	**Billing Determinants (MW)**	**Yearly ($/kW-yr)**	**Monthly ($/kW-m)**	**Weekly ($/MW-w)**	**On-Peak Daily ($/MW-d)**	**Off-Peak Daily ($/MW-d)**	**On-Peak Hourly ($/MW-h)**	**Off-Peak Hourly ($/MW-h)**
Reactive Supply and Voltage Control									
Total	$ 5,488.1								
less Credits	$ 408.5								
Net	$ 5,079.5								
Point-to-Point	$ 1,296.9	720	$ 1.801	$ 0.150	$ 34.63	$ 6.93	$ 4.93	$ 0.43	$ 0.21
Network	$ 3,782.6	2571	$ 1.471	$ 0.123					
		3291							
Calculation of credits (short term firm and non-firm revenues from this service)									
2003/2004 in MW			n/a	2,425	-	3,930	-	40,949	-
Revenue ($1000/yr)			n/a	363.70	-	27.23	-	17.61	-
	Allocated on 12CP			Col 3/12	Col 3/52	Col 5/5	Col 3/365	Col 6/16	Col 3/8760

Notes:
1. The transmission customer (Point-to-Point or Network) must purchase this service from the transmission provider
2. Credits are revenue from Reactive Supply and Voltage Control associated with
   short term firm and non-firm point-to-point service
3. 12CP usages are 720 MW and 2100 MW respectively

Maritime Electric Company, Limited

Transmission Tariff Rates Design

November 30, 2006

Table of Contents

ATTACHMENTS

1.0 INTRODUCTION

An Open Access Transmission Tariff (Tariff) defines the terms, conditions and price for access to an electric utility's transmission system for other users on the same basis as the utility uses its transmission system for serving its own load.

This document explains the approach followed by Maritime Electric Company, Limited (MECL) to design its Tariff. MECL'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.

The current situation in PEI has MECL supplying 90% of the PEI load under a fully bundled, cost of service regulatory model. The remaining 10% of the load is supplied by the City of Summerside Electric Department. Since Spring 2002, Summerside has been purchasing its electricity supply from off-Island sources and MECL has been providing transmission wheeling service for the City at rates based on NB Power's Tariff.

The wheeling arrangement with Summerside, while working satisfactorily for both parties, is understood to be temporary pending the development by MECL of a Tariff of its own. The recent interest in merchant wind power development in PEI is a second driver for MECL to have its own Tariff in place.

MECL is thus proposing for approval by the Island Regulatory and Appeals Commission a Tariff that provides for wholesale transmission access. This will meet the needs of Summerside and merchant wind power developers and will also comply with the reciprocity requirement of the FERC Pro Forma Tariff.

For implementing the Tariff, MECL is proposing that:

- MECL will follow the code of conduct in the proposed Tariff as the means of assuring non-discriminatory access to the transmission system (rather than undergo a functional unbundling of MECL).

- MECL is investigating the option of contracting with the New Brunswick System Operator (NBSO) for the Open Access Same-Time Information System (OASIS) function in the future.

2.0 TRANSMISSION RATE MAKING PRINCIPLES

There is a significant body of jurisprudence related to the principles to be applied in the design of monopoly services. These have been developed mainly for provision of completely bundled service to end-use customers for the supply of natural gas, electricity, water and telecommunication services.

The accepted approach is to group similar customers into classes. Costs are then allocated to each customer class based on the principle of "cost causation". The cost of the portion of the system required to service a customer class, which is "used and useful" for that customer class, is allocated to that class. This follows from the need for fairness so that customer classes pay for the cost of the service provided and do not unduly subsidize another class. The overall objective is that rates be "just and reasonable" without "undue discrimination" and based on the "revenue requirement".

Rate making principles for electric transmission services have been developed only in the last 15 years. They have been driven mainly in North America by the FERC, which is empowered to regulate the American Federal Power Act (FPA). While the FERC has no jurisdiction in Canada, its principles have influenced policy makers here.

Amendments to the FPA in 1992 provided for competition in electricity supply at the wholesale level, where wholesale is defined as "purchase for resale". Since then, the FERC has significantly influenced transmission tariff design with the issuance of both its Transmission Pricing Policy Statement (1994) and Order 888, which includes the Pro Forma Tariff (1996).

This section provides details about transmission rate making principles under the following headings: the Transmission Pricing Policy Statement developed by the FERC in the United States (Section 2.1); and the FERC's Order 888 Pro Forma Tariff (Section 2.2).

2.1 FERC Transmission Pricing Policy Statement

The Transmission Pricing Policy Statement[1], issued by the FERC on October 26, 1994, specifies five principles regarding the pricing of transmission services. Instead of promoting a particular approach to rate design, the policy statement provides flexibility in the development of transmission pricing. The FERC also states that the pricing of transmission "be just and reasonable and not unduly discriminatory or preferential"[2].

- Transmission Pricing Must Meet the Traditional Revenue Requirement
  "First a utility must determine its total company revenue requirement, the capital component of which traditionally has been measured by embedded (depreciated original) cost. Second, a utility must allocate among individual customers or classes of customers that portion of the total revenue requirement that is attributable to providing transmission services, in a manner which appropriately reflects the costs of providing transmission service to such customers or classes of customers. Finally, the utility must design rates to recover those allocated costs from each customer class. Different customers may pay different rates if they use the system in different ways".[3]

- Transmission Pricing Must Reflect Comparability
  This principle requires that an *"open access tariff that is not unduly discriminatory or anti-competitive should offer third parties access on the same or comparable bases, and under the same or comparable terms and conditions, as the transmission provider's uses of its system."*[4]

- Transmission Pricing Should Promote Economic Efficiency
  The FERC specifies that transmission pricing should promote; "*... efficient expansions of transmission capacity; efficient location of new*

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1 Inquiry concerning the Commission's pricing policy for transmission services provided by Public Utilities under Federal Power Act; Policy Statement, October 26, 1994, Docket No. RM93-19-000, 18 CFR 2, 59 FR 55031 (http://www.ferc.gov/new/policy/pages/rm93-19.pdf).

2 FERC's Transmission Pricing Policy Statement, p5.

3 FERC's Transmission Pricing Policy Statement, pg6, referenced from 67 FERC at 61, 490.

4 From the FERC's comparability standard *(American Electric Power Service Corporation (AEP)*, 67 FERC 61,168 (1994) at 61,490.

generators and new loads; efficient use of existing transmission facilities, and, efficient dispatch of generating resources".[5]

- Transmission Pricing Should Promote Fairness
  "As a general matter, transmission pricing should be fair and equitable"[6]. Current transmission customers should not pay for the cost of providing wholesale transmission services to third-parties nor should third-party customers subsidize existing customers. *"The major purpose of transmission pricing reform should be to provide more efficient price signals, particularly for new transmission uses and not simply to reallocate sunk costs"*[7].

- Transmission Pricing Should be Practical
  "Transmission pricing should be practical and as easy to administer as appropriate given the other pricing principles"[8].

The FERC refers to pricing proposals as being either "conforming" or "non-conforming." Conforming pricing proposals are based on the first two principles. While the other three principles continue to be viewed as goals that a conforming proposal must strive to meet, achievement is balanced against the need for transmission rates that are "just and reasonable".

2.2 Order 888 Pro Forma Tariff

In 1996, the FERC issued Order 888[9], which included a Pro Forma Tariff. The order required all utilities under FERC jurisdiction to file a tariff which specified the terms, conditions and a pricing methodology that conformed to the pricing principles. The FERC was open to non-conforming pricing proposals, but required that the proponent demonstrate that it was superior to the Pro Forma

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5 FERC's Transmission Pricing Policy Statement, p7.
6 FERC's Transmission Pricing Policy Statement, p7.
7 FERC's Transmission Pricing Policy Statement, p7.
8 FERC's Transmission Pricing Policy Statement, p7.
9 Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities Order No. 888 Final Rule (Issued April 24, 1996), United States Of America 75 FERC 61,080, 18 CFR Parts 35 and 385 [Docket Nos. RM95-8-000 and RM94-7-001] (http://www.ferc.gov/news/rules/pages/order888.htm).

Tariff approach. In addition, through Order 889[10] the FERC standardized the reservation process through which transmission services could be transacted. This includes the requirement for an Open Access Same-Time Information System (OASIS) and the Standards of Conduct with respect to non-discriminatory control of third party information.

2.2.1 Pro Forma Transmission Services

Under the Pro Forma Tariff the transmission provider is responsible for providing reliable and efficient dispatch and transportation of energy (delivery service only). These services are known as Network Integration Transmission Service (network service) and Point-to-Point Transmission Service (point-to-point service). The transmission provider is not obligated to supply either energy or generation capacity.

Network service is firm transmission service delivered to the high side of the customer's substation transformers. It includes the delivery of both capacity and energy. *"It allows a Transmission Customer to integrate, plan, economically dispatch and regulate its Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load customers. Network Integration Transmission Service also may be used by the Transmission Customer to deliver non-firm energy purchases to its Network Load without additional charge."*[11]

Point-to-point service[12] refers to the reservation of capacity and/or the transmission of energy from a point of receipt to a point of delivery. This service is available on either a firm or a non-firm basis.

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10 Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct Order No. 889 Final Rule (Issued April 24, 1996), United States Of America 75 FERC 61,978, 18CFR Part 37 [Docket No. RM95-9-000] (http://www.ferc.gov/news/rules/pages/order889.htm).

11 FERC Glossary (http://www.tsin.com/gloss.html).

12 FERC Glossary (http://www.tsin.com/gloss.html).

2.2.2 Ancillary Services and Curtailments

The Pro Forma Tariff requires that the transmission provider make some ancillary services available at regulated rates. Services that must be available are as follows and rates for such services are provided in the 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 Reserve – Spinning Reserve Service [Schedule 5]
- Operating Reserve – 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.

2.2.3 Postage Stamp Rate

A postage stamp rate[13] 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.

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

The Pro Forma Tariff allocates a relevant revenue requirement to users based on their contribution to the transmission system peak load. The postage stamp rate is determined by dividing the relevant revenue requirement ($/yr) by the applicable peak load (MW) to get an annual rate ($/MW-yr).

While the overall method is clear, there are significant issues regarding what constitutes a relevant revenue requirement for what type of service and what peak loads should be used. The traditional FERC approach is to allocate costs to the different service classes based on a rolling 12 month average of the monthly coincident peak loads and, where metering is sufficient, to bill individual usage on the same basis. In cases where eligible transmission customers may not have the necessary metering to determine coincident peak contributions, the actual customer billing of services has to be done using other billing determinants such as non-coincident peak loads. (This is the situation in New Brunswick, where non coincident peak loads are used for the billing determinants.)

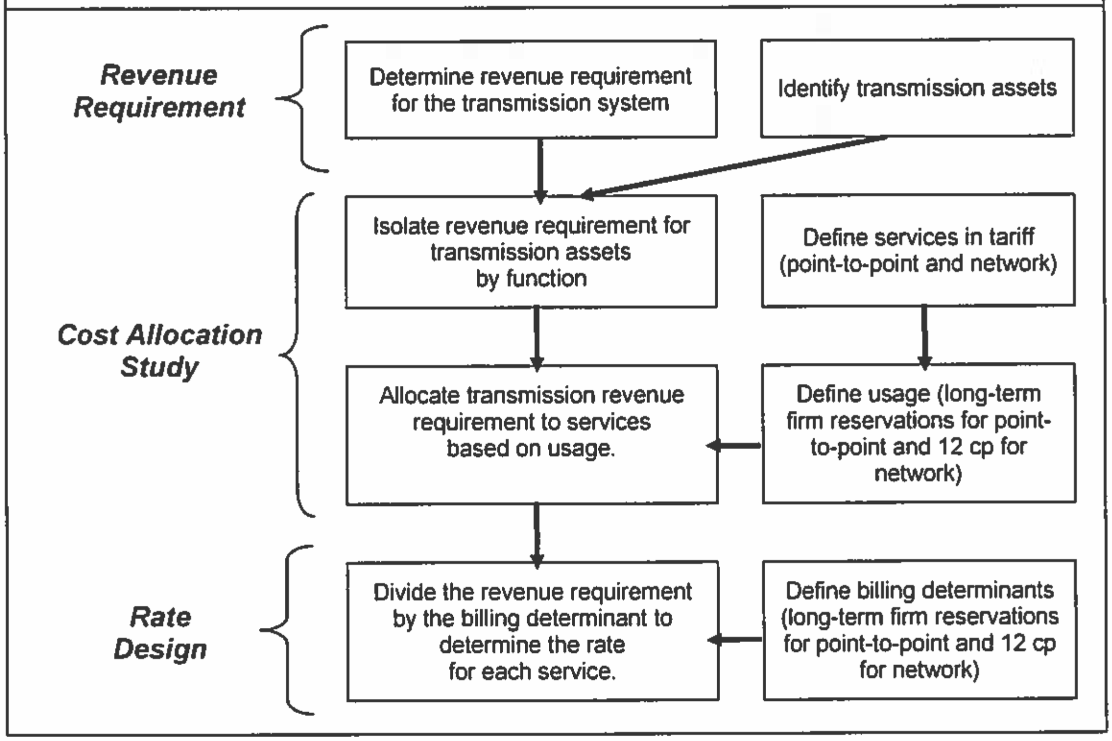
2.2.4 Influence Outside the United States

Although the FERC has no direct jurisdiction outside the United States, it has had significant influence on the implementation and design of external tariffs. First, the FERC has instituted a reciprocity requirement on all non-jurisdictional utilities that use the tariffs of jurisdictional utilities. Second, non-jurisdictional companies wishing to sell electric power at market based prices in the U.S. must acquire a power marketing authority license from the FERC. Thirdly, the license requires that the reciprocal transmission access to be provided is done under a tariff that is equal to or superior to the Pro Forma Tariff. The effect of this latter point has lead to the development and implementation of Pro Forma tariffs by utilities in Canada and Mexico. Today the Order 888 Pro Forma Tariff is the most commonly applied tariff in Canada as well as the United States.

3.0 TRANSMISSION SERVICES COST ALLOCATION AND RATE DESIGN

A transmission tariff defines the terms, conditions and price under which a user (transmission customer) can gain access to the transmission provider's infrastructure (transmission assets). The methodology of developing efficient and equitable tariff rates can be summarized in the three-step process illustrated in Figure 3-1.

Figure 3-1: Overview of the Steps taken in the Development of a Tariff.



It should be noted that this process is the same as that detailed in the first pricing principle of FERC. *"First a utility must determine its total company revenue requirement, ... Second, a utility must allocate ... the total revenue requirement ... in a manner which appropriately reflects the costs of providing transmission service ... Finally the utility must design rates to recover those allocated costs from each customer class."*[14]

[14] Inquiry concerning the Commission's pricing policy for transmission services provided by Public Utilities under Federal Power Act; Policy Statement, October 26, 1994, Docket No. RM93-19-000, 18 CFR 2, 59 FR 55031 [31,143] (http://www.ferc.gov/news/policy/pages/rm93-19.pdf).

3.1 Transmission Revenue Requirement

The first step in designing an efficient and equitable transmission tariff is to determine the appropriate revenue requirement that must be recovered from the sale of services. The total revenue requirement related to transmission services for the MECL transmission system has been determined to be $6,052,000 for the year 2005.

This revenue requirement includes all costs (amortization costs, operation, maintenance and administration costs, finance charges, income taxes and a regulated return on equity investment). This revenue requirement relates to all transmission assets and has been determined based on MECL's 2006 Cost of Service Study (which is based on historical 2005 year data, and was filed with the Island Regulatory and Appeals Commission on October 4, 2006). A summary breakdown of MECL's 2005 revenue requirement is shown in Schedule 4-1 of Attachment A. The components of the revenue requirement are summarized in Table 3-1.

Table 3-1
MECL Transmission System 2005 Revenue Requirement

Revenue Requirement Component	$ x 1,000
Asset amortization expense	1,464
Operating, Maintenance & Administration expenses	1,839
Interest, taxes and return on equity	2,749
TOTAL	6,052

In addition to the costs of all transmission lines at voltages of 69 kV and 138 kV and the substations between transmission lines, the above revenue requirement also includes the costs associated with the step up transformers for some of MECL's generators (these step up transformers are included with transmission substations in the Company's accounting system). Because these step up transformers are not used in providing the transmission services offered under the Tariff it is necessary to identify a component of the revenue requirement associated with these assets. Only after such a breakdown is completed can costs be allocated to specific services.

Amortization costs can be linked directly to specific assets because the gross and net asset value of each asset is accounted for in the MECL's accounting records. OM&A is generally allocated to each asset based on gross asset value, while interest, taxes and return are allocated based on net asset value.

3.2 Cost Allocation

The purpose of the cost allocation, which is the second major activity in the development of transmission rates, is to allocate the appropriate revenue requirement (i.e. the costs associated with transmission) to the appropriate services. The following steps are required to do this in a manner that is both efficient and equitable:

- Definition of the transmission services is to be provided
- Definition of the basic functions of the transmission system
- Allocation of transmission revenue requirements to the different functional uses of the system
- Determination of system usage by service
- Allocation of the functional costs to the transmission services

3.2.1 Services Provided in MECL Tariff

The MECL Tariff provides for point to point transmission service that is consistent with the FERC Pro Forma Tariff. In addition, the ancillary service of Scheduling, System Control, and Dispatch is an obligatory service that must be provided by the transmission provider and taken by the transmission customer. The rate design of these two services is detailed here in Section 3 while the rates for the other ancillary services which are supplied by generators are detailed in Section 4 of this document.

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 would be a reservation of 20 MW from the New Brunswick interconnection at Murray Corner to the metering point in the Sherbrooke Substation for the City of Summerside. This service is available on either a firm or a non-firm basis. The primary points of receipt and/or delivery can also be changed on a non-firm basis to secondary points only if there is sufficient transmission capacity available after all other uses of the system have been accommodated. In other words, when a firm reservation is used to deliver power between secondary points of receipt or points of delivery, the service provided is subservient to all other uses of the grid, including non-firm point-to-point service. Point-to-Point Service is usually used for wholesale transactions between systems rather than for the direct supply of load within a system.

Network Service is firm transmission service for the delivery of both capacity and energy to the high side of the customer's substation transformers. It is usually used for supply of load within the system. In PEI, MECL uses network service for the delivery to the 22 substations supplying its load across the Province. The City of Summerside does not use network service because the Summerside distribution system has only one supply point from the MECL transmission system.

Since in PEI only the MECL load is served on a network service basis, the proposed Tariff does not include rates for network service. However, as part of the rate design, the rates for network service are calculated on a basis that is consistent with the FERC Pro Forma Tariff. This ensures an appropriate allocation of costs between MECL as a user of network service and the other users of the transmission system who will be taking point to point service.

Scheduling, System Control and Dispatch Service is required to schedule the movement of power into, out of, through or within an area. Only the system operator for the area in which the transmission facilities are located can provide this service.

3.2.2 Transmission Functions

The services defined in the previous section use different parts of the transmission system. The purpose of this section is to identify which assets are used to provide which services. For the purposes of the MECL Tariff, transmission assets have been grouped into four main functional groups as follows:

- Generation Related Assets
- Bulk Network Assets
- City of Summerside Related Assets
- Energy Control Centre Assets

In order to be able to perform this allocation of the transmission assets and their associated costs, it is necessary that the division point between functional groups be defined. The division points and the types of assets allocated to the different functions are explained in detail below:

Generation Related Transmission Assets (GRTA) are those assets that serve the function of connecting generation units to the shared transmission system. They consist of generator step up transformers (GSUs), a portion of the substation assets, and any transmission lines whose primary purpose is to connect a generator to the transmission system. The GSUs are easily identified because they are directly connected to the low voltage output of the generator. A portion of the substation assets is not so easily identified because of the difficulty in defining a division point between GRTA and Bulk Network assets. In separating out the GRTA from the rest of the MECL transmission assets, a portion of the substation assets at the Charlottetown and Borden Substations was allocated to the GRTA function on the basis that each individual generating unit needs a breaker position in order to be able to synchronize and connect to the system. These assets and the associated revenue requirements are to be recovered directly from the generation owners and not collected in the rate for the transmission tariff. For any new generation, the generator is responsible for the cost of any additional generation related transmission assets that are required to connect the new generator. In the FERC Pro Forma Tariff, as well as the MECL Tariff terms and conditions, these types of assets are referred to as direct assignment facilities.

Bulk Network Assets make up the main portion of the 69 kV and 138 kV transmission system. The PEI Bulk Network has two components: the interconnection with New Brunswick and in-Province assets. The submarine cable facilities that connect the MECL system to the New Brunswick system are owned by the Province of PEI. These facilities consist of the two submarine cables, transmission lines connecting the cables to MECL's Bedeque Station and voltage control equipment and two breaker positions at the Bedeque Station. The Province leases the interconnection facilities to MECL for a nominal consideration. Under the lease agreement, MECL is responsible for the operation and maintenance of the submarine cables facilities.

The in-Province assets consist of all MECL 69 kV and 138 kV substations and transmission lines that are not allocated as generation related or related to the City of Summerside load. However, costs associated with 69 kV distribution substations or portions of 69 kV distribution substations used only to serve MECL load are not included in the Bulk Network assets; instead, they have been included with distribution system assets in MECL's 2006 Cost of Service Study.

Summerside Related Assets are those parts of the transmission system which are owned by MECL and used only to serve the City of Summerside load.

Energy Control Centre Assets are assets that support the operation of the transmission system. These assets consist of a portion of the MECL Energy Control Centre building, computer systems and other related equipment required for system operator functions. These are the functions that are to be charged under the Tariff through the service called Scheduling, System Control and Dispatch.

3.2.3 Functional Allocation of Costs

The allocation of the transmission services revenue requirement of $6,052,000 to the functional uses of the system is shown in Schedule 1-1 of Attachment A and the results are summarized in Table 3-2 below.

Table 3-2
Functional Allocation of Revenue Requirements

Functional Use	Revenue Requirement Share ($ x 1,000)
Generator Related	28
Bulk Network Related	5,772
Summerside Related	5
Energy Control Centre Related	248
TOTAL	6,052

As shown in the above table, the functional costs are allocated as follows:

- GRTA costs are allocated as direct assignment charges to generators ($28,000) and in the case of MECL-owned generators are recovered from the MECL load customers through MECL's rates for bundled electricity service.
- Bulk Network costs are the common use portion of the transmission system and are allocated as revenue requirement costs to be collected from transmission services under the Tariff ($5,772,000).
- Summerside costs ($5,000) will be recovered from the City of Summerside.
- Energy Control Centre costs are allocated to Scheduling, System Control and Dispatch and are to be collected through Tariff rates for that service ($248,000).

3.2.4 Determination of System Usage

Usage of the system by various services must be defined in order to allow the revenue requirement to be allocated to the services. The challenge with usage is to select metrics for each of the services such that the cost allocation meets the appropriate rate making principles. "Cost causation" and "used and useful" principles are the two most relevant to the issue of what usage to apply for the allocation of revenue requirements.

The allocation of the transmission revenue requirement in the MECL cost allocation analysis to point-to-point and network services is based on the approach prescribed by the FERC through Order 888. This approach is based on the principle that the monthly coincident peak system load, or usage, is a fair measure upon which to allocate the revenue requirement of the transmission system. Coincidental peak load is defined as the sum of two or more peak loads that occur in the same time interval.[15] The use of 12 monthly coincident peaks balances the "cost causation" and "used and useful" principles of transmission tariff rate making, whereas the use of a single coincident peak would tend to increase the allocation of revenue requirement to network services and understate the usefulness of the system to point-to-point services.

The FERC approach to the treatment of the point-to-point component of the load is incorporated in Section 34.3 of the Pro Forma Tariff (Determination of Transmission Provider's Monthly Transmission System Load) which states:

The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly System Peak minus the coincident peak usage of all Firm Point-to-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-to-Point Transmission Servcie customers.[16]

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15 Energy Information Administration (EIA) Glossary, (http://www.eia.doe/gov/cneaf/electricity/page/glossary.html).

16 FERC Order 888 Attachment D, the Pro Forma Tariff Terms and Conditions.

The substitution of point-to-point reservations for actual use is done in recognition of the fact that the transmission provider is fully committing the reserved capacity on a long-term firm basis. The transmission provider must design the transmission system to accommodate the full use of the reserved capacity at any time, including the time of monthly system peak. No allowance for diversity can be made.

In the case of the MECL system, the average of the monthly firm reservations for the year 2005 was approximately 14.0 MW. The level of long-term firm reservations is based on reservations by the City of Summerside in 2005. This reservation quantity is expected to remain relatively constant for the foreseeable future. The results are shown in the Table 3-3.

Table 3-3
Transmission System Usage

Usage	Quantity (MW)
Long-term firm reservations	14.0
Average of MECL network load at the time of the 12 monthly system peaks in 2005	161.3
TOTAL	175.3

This information is used in the allocation of the transmission system revenue requirement.

3.2.5 Allocation of Revenue Requirements to Services

The last step in the cost allocation analysis is to allocate total transmission costs to the services that will be offered under the Tariff. As noted above, these are point-to-point service, network service and the Scheduling, System Control and Dispatch Service.

The transmission revenue requirement for point-to-point and network services has been determined in Section 3.2.3 as $5,772,000/year. However, the transmission provider also collects revenues for the provision of services in addition to long-term firm services. These include short-term firm and non-firm point-to-point services and power factor penalties.

A projection of these revenues is subtracted from the gross revenue requirement prior to the allocations to point-to-point and network service. The projection of this miscellaneous revenue is $225,000. Therefore, the revenue requirement for allocation is reduced to $5,547,000.

This revenue requirement is allocated to the point-to-point and network transmission services based on their load ratio share of the system. Applying 14.0 MW for point-to-point reservations and 161.3 MW for network service gives the allocation of costs to these services as shown in Table 3-4.

Table 3-4
Transmission Services Revenue Requirements

Service	Usage (MW)	Share	Revenue Requirement ($ x 1,000)	Per Unit Revenue Requirement ($/MW-year)
Point-to-Point	14.0	8.0%	443	31,644
Network	161.3	92.0%	5,104	31,644
TOTAL	175.3	100.0%	5,547	31,644

The revenue requirement for each service can also be expressed on a cost per unit of usage basis as shown in Table 3-4. The cost per unit of usage for point to point service and network service is the same because the allocation of the transmission revenue requirement to these services was done on the basis of usage.

3.3 Rate Design

Now that costs have been allocated to specific services, it is possible to design rates to recover these costs. This is essentially the third step referenced in the first pricing principle of FERC under which the transmission provider can recover its revenue requirement. This design of rates involves the following:

- Selection of a rate structure
- Selection of billing determinants for each service
- Determination of rates using the billing determinants to collect the revenue requirements

3.3.1 Postage Stamp Rate Structure

A postage stamp rate 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 destination. Although the most common approach in North America has been to use postage stamp rates, alternative transmission service pricing structures have been identified and used in some jurisdictions. The alternatives to a postage stamp rate include location based (zonal or nodal) pricing, flow-based rates and distance based rates.

MECL's Tariff is based on postage stamp rates, which is the approach applied in the FERC Order 888 Pro Forma Tariff. This approach has also been adopted in New Brunswick, Nova Scotia, Saskatchewan, Manitoba and Quebec. British Columbia and Alberta have opted for zonal rate approaches. Most U.S. utilities have implemented the Pro Forma postage stamp approach but there are cases where locational-based marginal pricing, (Pennsylvania, New Jersey, Maryland Interconnection), zonal (New York Power Pool), flow gate (Midwest Independent System Operator) and distance based (Mid Area Power Pool, Maine Electric Power Company) have been approved by FERC. The decision to deviate from the postage stamp approach in these areas has been influenced by the structural nature of those systems and the markets that they serve. Systems with tightly meshed transmission networks like MECL's have generally all adopted the postage stamp approach.

To a large extent, the characteristics of the wholesale market will determine the ability of a transmission tariff design to promote efficient use of assets. For example, in the presence of persistent congestion it can be advantageous to use location-based pricing. Increased transmission costs across a congested interface will discourage such transactions thereby tending to alleviate the congestion. In markets where congestion is not an issue such as inside PEI, there is little value in adopting a locational-based marginal pricing structure.

The PEI system has little transmission congestion, a centralized system operator and a desire to minimize the costs and complexity of the implementation of a transmission tariff. Given these factors and the aforementioned discussion, MECL proposes a postage stamp rate as the most appropriate structure for the recovery of the embedded cost of MECL's transmission system.

3.3.2 <u>Definition of Billing Determinants</u>

In order to determine the price that will be charged to users of a particular service, the billing determinant must be defined. The price is then calculated by dividing the annual costs by the annual billing determinants.

As stated in Section 2.2.3, the FERC approach is to allocate costs to the different transmission services based on the average of the 12 monthly coincident peak loads and where metering is sufficient to bill individual usage on the same basis. Also, in Section 3.2.4, in allocating costs to the point-to-point component of the load, the total of the reserved capacity of all long-term firm point to point customers is used.

On the MECL system, metering is sufficient to enable using the monthly peak load for billing. Thus, for the MECL tariff, the billing determinants for point-to-point and network service are the same as the system usage quantities shown in Table 3-3 and used for cost allocation.

3.3.3 Determination of Rates

Given that the revenue requirement and billing determinants have been defined for each service, the nominal rate is merely the revenue requirement for the service divided by the respective billing determinant. Table 3-6 shows the calculation of the nominal annual rate for each service. (Because the billing determinants are the same as the system usage values used for cost allocation, the nominal rate is the same as the per unit revenue requirement shown in Table 3-4.)

Table 3-6
Determination of Nominal Rates by Service

Services	Revenue Requirement ($ x 1,000/year)	Billing Determinant (MW)	Nominal Rate ($/MW-year)
Point-to-Point Services			
- Transmission	443	14.0	31,644
- Schd, Control and Dispatch	19	14.0	1,363
Network Services			
- Transmission	5,104	161.3	31,644
- Schd, Control and Dispatch	220	161.3	1,363

For transmission service, it is a common industry practice in North America to apply what is frequently referred to as Appalachian pricing. In Appalachian pricing, the short-term services are priced higher for an equivalent time period. This concept has been approved by FERC[17] and is used in New Brunswick and several other jurisdictions n Canada.

The Appalachian pricing approach applied by NB Power in its Tariff and proposed for the MECL Tariff defines various short-term rates for point-to-point service as a fraction of the yearly rate as follows:

[17] Appalachian Power Company, 39 FERC, 61,296 (1986) and NY State Ele4ctric and Gas Company, 92 FERC 61,169 (August 17, 2000).

Yearly	=	Nominal Rate
Monthly Rate	=	Yearly Rate/12
Weekly Rate	=	Yearly Rate/52
On-Peak Daily Rate	=	Weekly Rate/5
Off-Peak Daily Rate	=	Yearly Rate/365
On-Peak Hourly Rate	=	On-Peak Daily Rate/16
Off-Peak Hourly Rate	=	Yearly rate/8,760

The rationale for the higher rates for On-Peak Daily Service (Weekly/5 instead of Yearly/365) and On-Peak Hourly Service (On-Peak Daily/16 instead of Yearly/8,760) is to provide a price signal that reflects the typically higher usage of the transmission system during on-peak hours.

Based on the overall revenue requirement defined, the application of the cost allocation analysis and the design of the end use rates just described, the rates proposed by MECL for approval by the Commission are detailed in Table 3-7.

Table 3-7
Summary of Transmission Service Rates

Point-to-Point Services	**Units**	**Transmission Service**	**Scheduling, System Control and Dispatch**
Yearly	$/MW-year	31,644	1,363
Monthly	$/MW-month	2,637	113.57
Weekly	$/MW-week	608.53	26.21
On-Peak Daily	$/MW-day	121.71	5.24
Off-Peak Daily	$/MW-day	86.70	3.73
On-Peak Hourly	$/MW-hour	7.61	0.33
Off-Peak Hourly	$/MW-hour	3.61	0.16
Network Service	$/MW-month	2,637	113.57

3.3.4 Power Factor Penalty in the Tariff

The Tariff includes a power factor penalty that will be applied for any month in which a transmission customer taking service under the Tariff to supply PEI load has a power factor of less than 90%. Under the proposed Tariff, the penalty paid per kVA (based on 90% of the metered kVA) that is in excess of the kW demand is 4 times the monthly transmission services rate (not to include any ancillary services) which is $10.55 (4 times $2.637).

The example below is intended to illustrate the calculation and is based on a 15,000 kW load at 0.88 power factor.

kVA demand	=	15,000 kW/0.88	=	17,045
90% of kVA demand	=	17,045 x 0.90	=	15,341
Excess amount	=	15,341 – 15,000	=	341
Monthly penalty	=	341 x $2.637/kW x 4	=	$3,597

Based on the year 2005 metering data, the anticipated revenue from power factor penalties is $18,000 per year. This anticipated revenue is subtracted from the gross revenue requirement as part of the revenue requirement allocation process as noted in Section 3.2.5 of this document.

4.0 ANCILLARY SERVICES COST OF SERVICE AND RATE DESIGN

Ancillary services are the support services that are required to enable the transmission system to transmit energy. They range from the actions necessary to effect and balance a transfer of electricity between buyer and seller to services that are necessary to maintain the integrity of the transmission system and enable it to be operated reliably.

This section addresses the development of rates for all the ancillary services that are provided from generators. The ancillary services provided from generators 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 the generator capacity for provision of the service.

4.1 Capacity-Based Ancillary Services

Capacity-based ancillary services are defined and provided in the MECL Tariff consistent with the numbered schedules used in the FERC Pro Forma Tariff. However, just as in the NB Power Tariff, some are further unbundled into component services as follows:

- Regulation and Frequency Response from Generation Sources Service [Schedule 3 in tariff] composed of:
    - Regulation, and
    - Load Following
- Operating Reserves – Spinning Reserve Service [Schedule 5 in tariff]
- Operating Reserves – Supplemental Reserve Service [Schedule 6 in tariff] composed of:
    - Supplemental (10-minute); and
    - Supplemental (30-minute)

MECL cannot provide the Regulation and Load Following Services because normally it does not run on-Island generation which could be used to regulate the energy flow on the NB/PEI interconnection. The New Brunswick System Operator (NBSO) 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 costs for these services are allocated by the NBSO on a load ratio share basis to New Brunswick, northern Maine and PEI. The PEI share of the costs for Regulation and Load Following Services is allocated on a load share basis between MECL and Summerside.

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 normally there are no on-Island generators running which 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 MECL and Summerside normally self-supply their 10-minute and 30-minute supplemental reserve requirements.

For the MECL Tariff, MECL is proposing to use the same rates for capacity based ancillary services as are in the NB Power Tariff. To the extent that MECL provides these services by purchasing them from the NBSO or elsewhere, the cost will be a flow through with no mark up. To the extent that MECL provides supplemental reserve from one of its own generating units, the charge will be as per the current charge in the NB Power Tariff.

NB Power used proxy unit costs in developing the rates in its Tariff for capacity based ancillary services. The revenue requirement for the capacity based services [Schedules 3, 5 and 6] was determined by multiplying the per unit cost of new proxy unit capacity for each service by the amount of capacity required to deliver the service. Current day costs for proxy units were used rather than the embedded cost of NB Power generation because they result in rates that are more appropriate in a market environment where generating services are competitively priced.

Once the revenue requirement was determined, it was allocated to the various services and rates were set in a manner similar to that used for transmission services in Section 3 of this report. For information purposes these calculations, which formed part of NB Power's 2002 Tariff filing with the New Brunswick Public Utilities Board, are shown in Attachment B.

4.2 Non-Capacity Based Ancillary Services

The MECL Tariff provides for the same non-capacity based ancillary services as are in the NB Power Tariff. These services are:

- Scheduling, System Control and Dispatch [Schedule 1 in Tariff]
- Reactive Supply and Voltage Control Service [Schedule 2 in Tariff]
- Energy Imbalance Service [Schedule 4 in Tariff]

Rates for Scheduling, System Control and Dispatch service are derived from the transmission revenue requirements in Section 3 of this document. The remaining two non-capacity based ancillary services are considered below.

4.2.1 Reactive Supply and Voltage Control Service

The pricing for Reactive Supply and Voltage Control from Generation Sources [Schedule 2] is determined based on the proxy unit costs of supplying it that NB Power used in its calculation of rates for Reactive Supply and Voltage Control Service from Generation Sources.

The proxy selected for this service by NB Power is a set of three 110 MVAr synchronous condensers. A synchronous condenser most closely simulates the Reactive Supply and Voltage Control services provided by a synchronous generator. The ability to operate at either a "leading" or a "lagging" power factor and the inertia that a synchronous condenser has makes it a reasonable proxy from the point of view of technical capabilities. For the PEI system, 30 MVAr is a more appropriate size for a synchronous condenser. In adapting the NB Power calculation, a higher $/MVAr cost was used for the 30 MVAr unit to reflect economies of scale.

The PEI system requirement for this service is based on the total MVAr output of in-province generators at the time of system peak plus an additional MVAr capability held in reserve to ensure dynamic system security. For most of the year, the reactive supply from the submarine cables and distribution system capacitor banks is sufficient to meet the PEI system requirements. However, for PEI loads of greater than approximately 190 MW, dynamic reactive supply from synchronous generators is required to be available to support the system voltage. This is provided by the Borden Unit 2 generator operating in synchronous condenser mode and/or by other on-Island generators when they are on line to limit the loading on the submarine cables to 200 MW. At the time of the 2005 PEI peak load, an estimated 6 MVAr were required from on-Island generators and a further 29 MVAr would have been required in the event of an outage to one of the 138 kV transmission lines between Memramcock and Murray Corner.

Whether they are purchasing point-to-point or network service, all transmission customers use this service. Therefore, the revenue requirement, net of charges for this service as provided with short-term firm and non-firm point-to-point service, is allocated to the two types of use. This allocation is done on the same basis as in Section 3.2 for the allocation of the revenue requirement associated with the transmission system. The respective usages are the long-term firm point-to-point reservations and the average of the 12 monthly coincident peak network loads coincident with the system peak.

The rate design is patterned after the design of the point-to-point and network services as explained in Section 3.3. The revenue requirement for this service for users of point-to-point service is divided by the long-term firm reservation quantity. The revenue requirement of this service for users of network service is divided by the average of the 12 monthly coincident peak net demands for network service. The Appalachian pricing approach is applied to this service in the same fashion as it is applied to the point-to-point transmission service. The end result is the rates for this service are as shown in the Table 4-3.

Table 4-3 Reactive Supply and Voltage Control Service Rates		
Point-to-Point Services	**Units**	**Rate**
Yearly	$/MW-year	2206.81
Monthly	$/MW-month	183.90
Weekly	$/MW-week	42.44
On-Peak Daily	$/MW-day	8.49
Off-Peak Daily	$/MW-day	6.05
On-Peak Hourly	$/MW-hour	0.53
On-Peak Hourly	$/MW-hour	0.25
Network Service	$/MW-month	183.90

4.2.2 Energy Imbalance

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.

Energy imbalance is a service that has no predictable required quantity and the cost of providing the service fluctuates with the real time cost of producing energy.

MECL cannot provide energy imbalance service because normally it does not run on-Island generators which could be used to regulate the energy flow on the NB/PEI interconnection. The NBNSO 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.

Currently in New Brunswick, the hourly energy imbalances at the NB/PEI interconnection point are settled financially for each hour at the New Brunswick market clearing price. At the NB/PEI interconnection point at Murray Corner the combined, or net, flow of energy is metered for each hour. MECL receives a single bill for energy imbalance charges and MECL then allocates these charges among the various users of the PEI transmission system. Table 4-4 shows an example of how this is done.

Table 4-4 Example of Energy Imbalance Charge Allocation			
	Scheduled for the Hour	**Actual for the Hour**	**Imbalance for the Hour**
MECL load	150	150	0
MECL supply sources:			
▪ Purchase from North Cape wind farm	7	5	-2
▪ Purchase from Vestas V-90 at Norway	2	2	0
▪ 39 WPPA with PEI Energy Corporation	22	22	0
▪ Purchases from off-Island sources	119	121	2
	150	150	0
Summerside load	15	16	1
Summerside supply sources:			
▪ Purchase from West Cape wind farm	6	6	0
▪ Purchases from off-Island sources	9	10	1
	15	16	1
Ventus export from West Cape wind farm	8	9	1
Loads at Murray Corner:			
▪ MECL receipts	119	121	2
▪ Summerside receipts	9	10	1
▪ Ventus receipts (deliveries)	-8	-9	-1
	120	122	2

In the above example, MECL would be billed for the supply of 2 MWh of imbalance energy for the hour (i.e. the difference between the actual delivery of 122 MWh to PEI for the hour and the scheduled delivery of 120 MWh to PEI for the hour).

MECL would allocate the charge for the 2 MWh of imbalance energy 2/3 to MECL and 1/3 to Summerside. In this instance, Ventus would not be allocated any of the charge for the 2 MWh of imbalance energy because Ventus did not contribute to the net imbalance for the hour.

5.0 SUMMARY

A listing of the monthly rates for all services to be available under the MECL Tariff is provided in Table 5-1 below.

Table 5-1
Rates for Service in MECL's Open Access Transmission Tariff

Services	Schedule in Tariff	$/MW-month
Scheduling, System Control and Dispatch	Schedule 1	113.57
Reactive Supply and Voltage Control	Schedule 2	183.90
Regulation	Schedule 3	44.50
Load Following	Schedule 3	102.83
Energy Imbalance	Schedule 4	N/A
Contingency Reserve – Spinning	Schedule 5	174.17
Contingency Reserve – Supplemental (10-Minute)	Schedule 6	454.17
Contingency Reserve – Supplemental (30-Minute)	Schedule 6	290.00
Point-to-Point Transmission Service	Schedule 7	2,637

Attachment A

Transmission Services Cost Allocation and Rate Design Analysis

Schedule 1-1

ALLOCATION OF YEAR 2005 TRANSMISSION COSTS BY FUNCTION

($ X 1,000)

	Gross plant in service	Accum. amortztn	Net plant in service	Amortztn expense	Allocated amortztn expense	OM&A expense	Allocated OM&A expense	Interest, return & taxes	Total cost	Credits	Total net cost
From 2006 Cost of Service Study:											
- total transmission system costs for 2005				1,464		1,871		2,749	6,083		
- less rental property income for 2005						31					
net transmission system cost for 2005				1,464		1,839		2,749	6,052		
Generation related											
- unit transformers	245	179	66	5	6	1	5	8	18	0	18
- substations	135	98	37	3	3	1	3	4	10	0	10
	380	277	103	8	9	2	8	12	28	0	28
Transmission system											
- Govt owned interconnectn	0	0	0	0	0	161	266	0	266	10	255
- substations	17,939	8,680	9,259	771	861	321	705	1,053	2,618	102	2,516
- lines	22,791	8,232	14,559	512	571	265	661	1,655	2,888	113	2,775
	40,730	16,912	23,818	1,283	1,432	747	1,632	2,708	5,772	225	5,547
Summerside related	79	65	14	1	1	1	2	2	5	0	5
Energy Control Centre	413	173	240	20	22	118	198	27	248	9	239
General											
- telecommunications	1,238	619	620	62		27					
- vehicles	175	-20	196	13		0					
- corporate	982	181	800	77		945					
Totals	43,997	18,207	25,790	1,464	1,464	1,839	1,839	2,749	6,052	234	5,818

Schedule 1-2

DEMAND ALLOCATION FACTORS

Service	Long term firm reservations for 2005 (MW)	Average of MECL 12 CP for 2005 (MW)	Allocation factors
Point to Point (S'side)	14.0		0.080
Network (MECL)		161.3	0.920
	14.0	161.3	1.000

Schedule 1-3

ALLOCATION OF FUNCTIONAL COSTS TO SERVICES

($ x 1,000)

	Amortization expense			OM&A expense			Interest, return & taxes					
	Trans system	Generatn related	Total	Trans system	Generatn related	Total	Trans system	Generatn related	Total	Total	Credits	Total
Point to Point Transmission	114	0	114	130	0	130	216	0	216	461	18	443
Network Transmission	1,317	0	1,317	1,502	0	1,502	2,492	0	2,492	5,311	207	5,104
Generation connection	0	9	9	0	8	8	0	12	12	28	0	28
Summerside connection	1	0	1	2	0	2	2	0	2	5	0	5
Sched, Sys Control & Dispatch	0	0	22	0	0	198	0	0	27	248	9	239
	1,433	9	1,464	1,634	8	1,839	2,710	12	2,749	6,052	234	5,818

Schedule 1-4

UNIT COSTS

Services	Total cost by service ($ x 1000)	Total usage by service (MW)	Annual unit cost ($ / MW - yr)	Monthly unit cost ($ / MW - mo)
Point to Point	443	14.0	31,644	2,637
Network	5,104	161.3	31,644	2,637
Subtotal	5,547	175.3		
Generation connection	28			
Summerside connection	5			
Sched, Sys Control & Dispatch	239	175.3	1,363	113.57
Total	5,818			

Schedule 2-1

RATES FOR POINT TO POINT TRANSMISSION SERVICE

Total annual cost by class		443	$ x 1,000
Total usage by class (1)		14.0	MW
Yearly (2)		31,643.77	$ / MW - yr
Monthly (3)	= Yearly / 12	2,636.98	$ / MW - mo
Weekly (3)	= Yearly / 52	608.53	$ / MW - wk
On-peak daily (3)	= Weekly / 5	121.71	$ / MW - day
Off-peak daily (3)	= Yearly / 365	86.70	$ / MW - day
On-peak hourly (4)	= On-peak daily / 16	7.61	$ / MWh
Off-peak hourly (4)	= Yearly / 8,760	3.61	$ / MWh

Notes: 1 Usage based on long term firm reservations

2 Firm service only

3 Firm or Non firm service

4 Non firm service only

Schedule 2-2

RATES FOR NETWORK TRANSMISSION SERVICE

Total annual cost by class		5,104	$ x 1,000
Total usage by class (average of 12 CP)		161.3	MW
Yearly		31,643.77	$ / MW - yr
Monthly	= Yearly / 12	2,636.98	$ / MW - mo

Schedule 2-3

RATES FOR SCHEDULING, SYSTEM CONTROL & DISPATCH SERVICE

Total annual cost		239	$ x 1,000
Total usage		175.3	MW

For Point to Point Service (1)

Yearly (2)		1,362.85	$ / MW - yr
Monthly (3)	= Yearly / 12	113.57	$ / MW - mo
Weekly (3)	= Yearly / 52	26.21	$ / MW - wk
On-peak daily (3)	= Weekly / 5	5.24	$ / MW - day
Off-peak daily (3)	= Yearly / 365	3.73	$ / MW - day
On-peak hourly (4)	= On-peak daily / 16	0.33	$ / MWh
Off-peak hourly (4)	= Yearly / 8,760	0.16	$ / MWh

For Network Service

Yearly		1,362.85	$ / MW - yr
Monthly	= Yearly / 12	113.57	$ / 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

Schedule 3-1

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES
COST OF SERVICE BASED ON PROXY SYNCHRONOUS CONDENSER UNIT

	Capacity (MVAr)	Capital cost ($ X 1,000 / MVAr)	Capital cost ($ millions)
Proxy unit for NB Power Tariff calculation	110	80	8.8
Proxy unit for MECL Tariff calculation	30	194	5.8

Expected service life	30	years
MECL annual fixed charges rate	10.3	%
Annual O&M costs	87	$ x 1,000

Estimated annual cost for a 30 MVAr synchronous condenser

Capital related	600	$ x 1,000 / yr
O&M	87	$ x 1,000 / yr
Total	688	$ x 1,000 / yr
Per unit cost	22.9	$ x 1,000 / MVAr - yr
Adjusted per unit cost	11.5	$ x 1,000 / MVAr - yr

Note: Adjusted per unit cost is 50 % of per unit cost of synchronous condenser because the service is provided from synchronous generators, which provide energy production as well as the reactive supply and voltage control service.

Estimated MVAr requirement from on-Island generators at 2005 system peak	6	MVAr
Additional MVAr requirement for dynamic system security	29	MVAr
Total MVAr requirement from on-Island generators	35	MVAr

Annual revenue requirement = 35 MVAr x 11.5 $ x 1,000 / MVAr - yr

= 401 $ x 1,000 / yr

Schedule 3-2

RATES FOR REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE FROM GENERATION SOURCES

Total annual cost		401	$ x 1,000
Less credits (note 2)		14	$ x 1,000
Net annual cost		387	$ x 1,000
Total usage		175.3	MW

For Point to Point Service

Yearly		2,206.81	$ / MW - yr
Monthly	= Yearly / 12	183.90	$ / MW - mo
Weekly	= Yearly / 52	42.44	$ / MW - wk
On-peak daily	= Weekly / 5	8.49	$ / MW - day
Off-peak daily	= Yearly / 365	6.05	$ / MW - day
On-peak hourly	= On-peak daily / 16	0.53	$ / MWh
Off-peak hourly	= Yearly / 8,760	0.25	$ / MWh

For Network Service

Yearly		2,206.81	$ / MW - yr
Monthly	= Yearly / 12	183.90	$ / MW - mo

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

2 Credits are revenue from Reactive Supply and Voltage Control Service associated with short term firm and non firm point to point service.

Schedule 4-1

MECL TOTAL FUNCTIONALIZED COSTS FOR 2005

($ x 1,000)

	Amortztn expense	OM&A expense	Interest, return & taxes	Credits	Total costs
Generation	1,798	4,699	5,188	28	11,657
Purchased power	3,073	68,792	1,220	0	73,085
Transmission system	1,464	1,871	2,749	31	6,053
Distribution substations	215	607	671	8	1,485
Primary distribution lines	1,852	1,898	4,356	291	7,815
Distribution line transformers	1,268	1,544	2,947	29	5,730
Secondary lines	643	721	1,484	97	2,751
Customer related	1,857	4,133	4,304	912	9,382
Totals	12,170	84,265	22,919	1,396	117,958

Notes: 1 Based on Schedule 4.1 of MECL's 2006 Cost of Service Study

2 Credits are miscellaneous revenues such as property rental and late payment penalties

Attachment B

Capacity – Based Ancillary Services

Attachment B

Capacity-Based Ancillary Services

Capacity-Based Ancillary Services

The capacity-based services are defined and provided in the tariff consistent with the numbered schedules used in the FERC Pro Forma Tariff. Some, however, are further unbundled into component services as follows:

- Regulation and Frequency Response from Generation Sources Service [schedule 3 in tariff] composed of:
  - Regulation, and
  - Load Following
- Operating Reserves – Spinning Reserve Service [Schedule 5 in tariff]
- Operating Reserves – Supplemental Reserve Service [Schedule 6 in tariff] composed of:
  - Supplemental (10-minute); and
  - Supplemental (30-minute)

The revenue requirement for the capacity based services [Schedules 3, 5 and 6] is determined by multiplying the per unit cost of new proxy unit capacity for each service by the amount of capacity required to deliver the service. Proxy units are used rather than the embedded cost of NB Power generation because they produce a more appropriate price for the services. Once the revenue requirement is determined, it is allocated to services and rates are set in a manner similar to that used fro transmission services in Section 3 of this report.

1.1 The Choice of Proxy Units

The two key guiding principles in the selection of proxy units were the technical capability of a facility to provide a service and the simplicity of the modeling. A proxy price would not be meaningful if the proxy unit could not reasonably be argued to be the type of facility that would be built to provide the service. On the other hand, there would be little benefit to a complex model that simulated a fleet of resources to exactly meet the required quantity of resources. The approach taken was to use the costs of a reasonable proxy facility to determine the cost per unit of service provided. That unit cost was then multiplied by the required quantity to calculate the revenue requirement for the total actual quantity of the service that is to be provided under the tariff.

Regulation, Load Following and Operating Reserve-Spinning are referred to as on-line capacity based services because they can only be provided by resources that are operating and connected to the system. A 400 MW combined cycle gas generation plant was selected as the proxy unit for the on-line ancillary services. The 400 MW configuration provides reasonable economies of scale and is a technically proven sizing. Such a unit could be on-line producing energy with some of its capacity and providing on-line capacity based ancillary services with the remainder. Also, the general assumption within the energy industry is that most new generation for the production of energy in the foreseeable future will be combined cycle gas turbine. The combined cycle plant has a lower capital cost per kW of capacity than other types of generation with the technical capability to provide these on-line services.

Operating Reserve-Supplemental Reserve Services are referred to as off-line capacity based services because the resources that provide these services are not required to be operating and connected to the system. For off-line capacity based ancillary services (Operating Reserve-Supplemental Reserve Service Schedule 6 in the tariff), a 100 MW simple cycle gas turbine was used as the proxy. Such a unit could be sitting off-line most of the time and providing it full capacity as off-line ancillary services (Supplemental Reserves). Its low capital costs make this type of unit more economical to provide the off-line reserve services than a combined cycle installation. Other types of generation with the technical capability to provide these services have higher capital costs. Note that there is a small additional cost for 10-minute reserve to account for the increased OM&A and capital costs associated with rapid start-ups.

The costs for the proxy unit to provide the capacity based ancillary services are based on previous estimates by NB Power. They are summarized in Schedule 1-0 of Attachment B. The fixed costs of capital identify the ongoing revenue requirement associated with the initial capital investment. The fixed costs of capital are based on the transmission business unit's weighted-average cost of capital established in the financial report of this filing and an estimate of inflation. The OM&A cost reflects the ongoing operations and maintenance costs for such units. The payments is lieu of taxes reflect the taxes that would be paid on the corporate income associated with the equity portion of the financing of the assets.

1.2 Requirements of Capacity Based Services

As the Operator of the Maritimes Control Area, the transmission provided has a responsibility to operate in accordance with NERC and Northeast Power Coordinating Council (NPCC) criteria. This includes the responsibility to determine the need for and to procure sufficient ancillary resources to reliably operate the electrical power network.

Additionally, the NB Power Tariff obligates the transmission provider to make all ancillary services available to all transmission customers. Therefore, the transmission provider must procure adequate generation resources to do so.

Transmission customers can purchase each of the ancillary services from the transmission provider whether they are taking point-to-point or network service. Therefore, the ancillary services are priced for both services. Transmission customers can self-supply the capacity-based ancillary services or purchase them from either the transmission provider or a third party. In fact, when a load is located outside of the Control Area, it may be technically infeasible for the customer to buy these services from New Brunswick even though the customer is supplied y power that is delivered across the NB Power transmission system. The costs of these capacity-based services are allocated on a load share ratio between NB Power loads and outside loads that are currently using these services. The NB Power system requirements for "Regulation and Frequency Response" and "Operating Reserves" are outlined below.

Regulation and Frequency Response

The total system requirements represent the total average requirements to runt he New Brunswick system and are based on the actual numbers for the New Brunswick system. The determination of the amount of this service, composed of both regulation and load following, required for the New Brunswick system has been calculated using empirical methods. The method can be described as follows. The total system load is broken into two components, a slowly varying trend which represents load following and a random higher frequency component with zero mean which represents regulation.

19 MW of regulation and 53 MW of load following is required for the New Brunswick system. Given that external customers carry a load ratio share obligation, the tariff's obligation is 16.76 MW of regulation and 46.74 MW of load following. This includes the responsibility to cover tie line variations for other utilities in the Maritimes but does not include the load in Nova Scotia. The details are in Schedule 1-2 of Attachment B.

Operating Reserves

The requirement within the tariff for operating reserves is a function of reliability criteria established by the Northeast Power Coordinating Council (NPCC). The quantity of each type of reserve will depend on both the size of the contingencies and the load being served.

Since the Maritimes Council Area is not operated as a single entity, each utility has been responsible for carrying its own reserve requirements. NPCC requires that each Control Area maintain sufficient Contingency Reserve (10-Minute Spinning and 10Minute Supplemental)[1] to cover 100% of the largest single contingency and 30-Minute Reserve to cover 50% of the second largest contingency.

The transmission customers' reserve obligation for each of the reserve services under this tariff will be based on their load share ratio. However, it will not exceed the obligations for the respective services that would exist if the 1st and

1 A minimum of 25% of the 10-minute reserves must be spinning.

2nd contingencies were 10% of the annual peak load for the Control Area. The portion of the 1st contingency in excess of 10% of the annual peak load (i.e. 5,000 MW) for the Control Area (i.e. Maritimes Control Area) shall be the direct responsibility of the owner of the 1st contingency. Similarly, the owner of the 2nd contingency will be responsible for supplying the operating reserve capacity that is the direct result of the 2nd contingency being in excess of 10% of the annual peak load.[2] Therefore, the 1st and 2nd contingencies to be addressed by the load-serving entities within the Maritimes Control Area are 500 MW and 458.1 MW respectively.

Operating Reserve sharing arrangements have been made with NB Power, Maritime Electric and Northern Maine. NB Power provides 125 MW of Contingency Reserve for the 1st contingency, of which 25% (31.25 MW) is spinning and 75% (93.75 MW) is Supplemental. NS Power also provides 50 MW of 30-Minute Reserve (i.e. the 2nd contingency). Maritime Electric, Northern Maine and NB Power assume their load ratio share of the remaining obligation. Of this, NB Power's obligations are 88.2 MW of 10-Minute Spinning and 242.5 MW of 10-Minute Non-spinning as well as 157.9 MW of 30-Minute Reserve. The details are contained in Schedule 1-2 of Attachment B.

1.3 <u>Summary of Revenue Requirements for Capacity Based Services</u>

The total revenue requirement for each service is the product of the quantity required multiplied by the cost per unit of service supplied as shown in Table 4-1.

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[2] The selection of 10% of the annual peak load is based on an historical rule-of-thumb used to determine the maximum size of a single generator for a specific system. Therefore, to the extent that a generator exceeds the 10% criteria, it must arrange for (supply, purchase or otherwise self-provide) the difference. This difference will be calculated annually and each generator's requirement will be rounded to the nearest 10 MW.

Table 4-1 Revenue Requirement of Capacity Based Services			
Services	**Revenue Requirement ($/kW-yr)**	**Services Required (MW)**	**Revenue Requirement ($1,000/yr)**
Regulation	81.99	16.76	1,374
Load Following	67.87	46.74	3,172
Spinning (10-Minute)	60.95	88.20	5,376
Supplemental (10-Minute)	57.81	242.5	14,020
Supplemental (30-Minute)	56.61	157.9	8,939

1.4 Capacity Based Service Rates

The annual cost of providing each service as a function of the usage is determined by dividing the total cost of providing the service by the usage of the respective service. For monthly point-to-point service and network service, the annual cost of providing each service on a $/kW basis is divided by 12 to determine the monthly rate. Point-to-point customers purchasing the ancillary services on a yearly, or monthly service, as well as network service, are billed at the monthly rate at the end of each calendar month as noted in the terms and conditions of the tariff. The rate for weekly point-to-point services is 1/52nd of the annual rate and the daily rate is 1/5th of the weekly rate. Hourly service is not available for the capacity based ancillary services due to the additional administrative burden of tracking how various point-to-point customers are fulfilling their obligations on an hourly basis. If hourly service were provided for the capacity based ancillary services there would be a potential impact on reliability should the policing of adequacy of reserves not be effective. The rates produced by this process are summarized in Table 4-2 and detailed in Attachment B.

Table 4-2 Nominal Rates for Capacity Based Ancillary Services			
Service	**Revenue Requirement ($1,000/yr)**	**Usage (MW)**	**Rate $/kW-month**
Regulation	1,374	2,571	0.04
Load Following	3,172	2,571	0.10
Contingency Reserve – Spinning	5,376	2,571	0.17
Contingency Reserve – Supplemental (10-Minute)	14,020	2,571	0.45
Contingency Reserve - Supplemental (30-Minute)	8,939	2,571	0.29

Capacity Based Ancillary Services
Cost Data for Proxy Units

Parameters		Greenfield Combined Cycle Gas Unit	Simple Cycle Gas Unit
Variable OM&A Cost	($M)	2.1	0.2
Fixed OM&A Cost	($M)	11.8	0.5
Capital Additions	($M)	0.4	0.2
	($/kW-Yr)	1.0	1.6
Capital Cost	($M)	428	60
	($/kW)	1070	600
Project Life	(Years)	25	25
Capacity	(MW)	400	100
Year Dollars	2006		
Escalation Rate	1.80%		
Interest Rate	7.15%		
Levelized Lifecycle Costs			
Variable OM&A Cost	($/MWh)	0.88	0.88
Fixed OM&A Cost	($/kW-Yr)	34.63	5.87
Capital Additions	($/kW-Yr)	1.17	1.88
Capital Cost	($/kW-Yr)	93.06	52.18

Notes:
1. The combined cycle unit is used as the proxy for on-line services
2. The simple cycle unit is used as the proxy for off-line services

Capacity Based Ancillary Services
Cost of Providing Services

		1	2	3	4	5	6	7	8	9	10	11
Ancillary Service	Proxy Source	Capacity (MW)	Capital Cost 2004$ ($/kW)	Exp'd Life (y)	Escalating Capital Charge ($/kW-yr)	O&M ($/kW-yr)	Payments in Lieu of Taxes ($/kW-yr)	Total Fixed Costs ($/kW-yr)	Contribution Reactive Supply ($/kW-yr)	Installed Capacity ($/kW-yr)	Energy Prod'n[3,4] ($/kW-yr)	Rate for Ancill. Service ($/kW-yr)
Regulation and Frequency Response												
Regulation	Combined Cycle - Greenfield (Fast AGC)	400	$1,032	25	$101.42	$31.39	$22.36	$ 155.17	$1.21	$17.31	$54.66	$81.99
Load Following	Combined Cycle - Greenfield (Slow AGC)	400	$1,032	25	$101.42	$30.48	$22.36	$ 154.26	$1.21	$17.31	$67.87	$67.87
Operating Reserves												
Spinning (10 Minute)	Combined Cycle - Greenfield	400	$1,032	25	$101.42	$30.18	$22.36	$ 153.96	$1.21	$17.31	$74.50	$60.95
Supplemental (10 Minute)	Combustion Turbine - Simple Cycle (quickstart)	100	$ 589	25	$57.85	$5.11	$12.75	$ 75.72	$0.60	$17.31	$0.00	$57.81
Supplemental (30 Minute)	Combustion Turbine - Simple Cycle	100	$ 579	25	$56.87	$5.11	$12.54	$ 74.52	$0.60	$17.31	$0.00	$56.61
		Sch 1.0	Sch 1.0 in 2004$	Sch 1.0	Sch 1.0	Sch 1.0		Col (4+5+6)	MVAR/MW *React Cost Note 5 *React Cost $/kVAR/yr	Assign		Col 7 - Col 6 -Col 9 - Col 10

Notes:	1. ICAP value based on Natsource 12 month quotes for 2003 escallated to 2004	Discount rate	10.3%
	2. MVAR/MW 48.4% (90% lagging power factor requirement)	Escallation	1.8%
	3. Capacity factor for regulation 40%		
	4. Capacity factor for load following 50%	6. Capacity factor for supplemental 10 minute reserve	0%
	5. Capacity factor for spinning reserve 55%	7. Capacity factor for supplemental 30 minute reserve	0%

Capacity Based Ancillary Services
MW Requirements

	1	2	3	4	5	6
	Maritimes Control Area	Nova Scotia	NB/N.Me./ PEI	PEI	Northern Maine	New Brunswick
Peak Load (using 2001/2002 12CP)	3926	1598	-	156	119	2053
Maritimes Control Area Load Share Ratio	100.00%			3.97%	3.03%	52.29%
Without Nova Scotia			100.00%	6.70%	5.11%	88.19%
Regulation and Frequency Response						
Regulation			19	1.27	0.97	16.76
Load Following			53	3.55	2.71	46.74
Operating Reserves (Contingency Reserves)						
Spinning (10 Minute)	125.0	25.0	-	6.7	5.1	88.2
Supplemental (10 Minute)	375.0	100	-	18.4	14.1	242.5
Supplemental (30 Minute)	229.1	50	-	12.0	9.2	157.9
Nominal first contingency relative to Maritimes Control Area 1CP load			5000 MW		10%	500
Actual first contingency						660
Nominal second contingency relative to Maritimes Control Area load					10%	500
Actual second contingency						458.1

Notes:
1. The smaller of the nominal and actual contingencies will be the tariff obligation
2. The spinning reserve requirement is typically 25% of the total 10 minute reserve
3. The 10 minute reserve requirement is 100% of the largest contingency
4. The 30 minute reserve is 50% of the second largest contingency

Capacity Based Ancillary Services
New Brunswick Usage

	1	2	3	4	5
		Network Service Billing Determinants			
	Usage by Point-to-Point MW	Total MW	Loads That Self Supply MW	Loads That Purchase From Third Party MW	Net Usage in Tariff MW
Regulation and Frequency Response					
Regulation	0	2571	0	0	2571
Load Following	0	2571	0	0	2571
Operating Reserves (Contingency Reserves)					
Spinning (10 Minute)	0	2571	0	0	2571
Supplemental (10 Minute)	0	2571	0	0	2571
Supplemental (30 Minute)	0	2571	0	0	2571
					Col (1+2-3-4)

Notes:
1. Customers also have the option to self-supply or purchase these services from a third party

Capacity Based Ancillary Services
Rate Design
Revised Version

	1	2	3	4	5	6'	6	7	8
	Revenue Req't ($/kW-yr)	Service Req'd (MW)	Revenue Req't ($1000/yr)	Usage (MW)	Rate for Pt-Pt ($/kW-yr)	Rate for Pt-Pt ($/MW-m)	Rate for Network ($/kW-m)	Rate for Pt-Pt ($/MW-w)	Rate for Pt-Pt ($/MW-d)
Regulation and Frequency Response									
Regulation	$ 81.99	16.76	$ 1,373.82	2571	$ 0.534	$ 44.50	$ 0.04	$ 10.27	$ 2.05
Load Following	$ 67.87	46.74	$ 3,172.38	2571	$ 1.234	$ 102.83	$ 0.10	$ 23.73	$ 4.75
Operating Reserves (Contingency Reserves)									
Spinning (10 Min.)	$ 60.95	88.2	$ 5,375.08	2571	$ 2.090	$ 174.17	$ 0.17	$ 40.19	$ 8.04
Supp. (10 Min.)	$ 57.81	242.5	$14,020.66	2571	$ 5.450	$ 454.17	$ 0.45	$ 104.81	$ 20.96
Supp. (30 Min.)	$ 56.61	157.9	$ 8,939.43	2571	$ 3.480	$ 290.00	$ 0.29	$ 66.92	$ 13.38
Totals		552.1	$32,881.37		$12.790	$1,065.67	$ 1.05	$ 245.96	$ 49.19
	Sch 2.1	Sch 2.2	Col 1 * Col 2	Sch 2.3	Col 3/Col 4	Col 5/12 *1000	Col 6 Rounded /1000	Col 5/52	Col 7/5

Capacity Based Ancillary Services
External Revenues
Revised Version

	1	2	3	4
	Rate ($/kW-yr)	**PEI (MW)**	**N. Maine (MW)**	**Total**
12NCP (12CP, Schedule 1.2 * Coincidence factor)		190.9	$ 145.7	336.6
Regulation and Frequency Response				
Regulation	0.534	$ 102	$ 78	$ 180
Load Following	1.234	$ 236	$ 180	$ 415
Operating Reserves (Contingency Reserves)				
Spinning (10 Minute)	2.090	$ 399	$ 305	$ 703
Supplemental (10 Minute)	5.450	$1,040	$ 794	$1,834
Supplemental (30 Minute)	3.480	$ 664	$ 507	$1,171
Total ($1000/yr)				$4,304

Notes:
1. These services are itemized separately on the Transmission income statement
2. The coincidence factor is assumed to be 81.7% (12NCP data not available)
3. The actual revenues will depend upon the extent to which the external parties choose to either self-supply or purchase from a third party. The estimate of these external revenues for the test year is $300,000.

Reactive Supply and Voltage Control
Service Cost

Ancillary Service	Proxy Source		1	2	3	4	5	6	7
			Capacity (MVAr)	Capital Cost 2003$ ($)	Expected Life (y)	Escalating Capital Charge ($/yr)	O&M ($/yr)	Payments in Lieu of Taxes ($/kW-yr)	Total Fixed Costs ($/yr)
Reactive Supply and Voltage Control									
	Synchronous Condensors[1]		330	$26.5	30	$2.48	$0.08	$0.90	$3.46
Adjustment to account for the fact that a synchronous generator is more economical because of the dual purposes served by the generator (energy production and reactive supply and voltage control)							50.0%		$ 1.73
Revenue requirement per VAR of capability					$/kVAR/yr				$5.25
Estimated peak VAR requirement					MVAR	246			
Additional VAR requirement for dynamic system security					MVAR	800			
	Total VAR requirement				MVAR	1046			1046
Revenue requirement total					$1000/yr				$ 5,488

Notes:

1. Based on historical costs escallated to 2003 dollars
2. Discount rate 10.3%
3. Escallation 1.8%
4. Note that the total nameplate capability of generation currently on the system is 2200 MVAR
5. The requirement divided by the nameplate capability is 1046 divided by ~~2360~~ 2200 47.5%

Reactive Supply and Voltage Control
Rate Design

	1	2	3	4	5	6	7	8	9
	Revenue Requirement ($1000/yr)	Billing Determinants (MW)	Yearly ($/kW-yr)	Monthly ($/kW-m)	Weekly ($/MW-w)	On-Peak Daily ($/MW-d)	Off-Peak Daily ($/MW-d)	On-Peak Hourly ($/MW-h)	Off-Peak Hourly ($/MW-h)
Reactive Supply and Voltage Control									
Total	$ 5,488.1								
less Credits	$ 408.5								
Net	$ 5,079.5								
Point-to-Point	$ 1,296.9	720	$ 1.801	$ 0.150	$ 34.63	$ 6.93	$ 4.93	$ 0.43	$ 0.21
Network	$ 3,782.6	2571	$ 1.471	$ 0.123					
		3291							
Calculation of credits (short term firm and non-firm revenues from this service)									
2003/2004 in MW			n/a	2,425	-	3,930	-	40,949	-
Revenue ($1000/yr)			n/a	363.70	-	27.23	-	17.61	-
	Allocated on 12CP			Col 3/12	Col 3/52	Col 5/5	Col 3/365	Col 6/16	Col 3/8760

Notes:
1. The transmission customer (Point-to-Point or Network) must purchase this service from the transmission provider
2. Credits are revenue from Reactive Supply and Voltage Control associated with short term firm and non-firm point-to-point service
3. 12CP usages are 720 MW and 2100 MW respectively

Open Access Transmission Tariff

January 1, 2017

Table of Contents

I. Common Service Provisions

SCHEDULES

ATTACHMENTS

I. COMMON SERVICE PROVISIONS

1 DEFINITIONS

1.1 Affiliate

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.1a Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of Maritime Electric Company, Limited (MECL)'s Transmission System in accordance with Good Utility Practice.

1.2 Application

A request by an Eligible Customer for transmission service pursuant to the provisions of the Open Access Transmission Tariff (OATT).

1.3 Business Day

A Business Day is Monday to Friday, inclusive, excluding statutory holidays which are posted on the MECL website for the Transmission Provider.

1.4 Completed Application

An Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

1.5a Control Area

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

2. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.5b Control Area Operator

The Control Area Operator for the MECL Transmission System is the NB Power Transmission System Operator (NB TSO). The Maritime Electric Energy Control Centre Operator (MESO) works with the Control Area Operator to meet the requirements of the Control Area.

1.6 Curtailment

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.7 Delivering Party

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.8 Designated Agent

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer as required under the OATT.

1.9 Direct Assignment Facilities

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the OATT. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the MECL Transmission Customer and shall be submitted to IRAC.

1.10 Eligible Customer

Any electric utility (including the Transmission Provider and any power marketer), power marketing agency, or any person generating electric energy for sale for resale and connected to the Transmission System; electric energy sold or produced by such entity may be electric energy produced in the Canada, United States or Mexico.

1.11 Facilities Study

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.12 Firm Point-to-Point Transmission Service

Transmission Service under this OATT that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this OATT.

1.13 Good Utility Practice

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region including those practices required by law.

1.14 Interruption

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.15 IRAC

The Island Regulatory and Appeals Commission.

1.16 Load Ratio Share

Ratio of a Transmission Customer's Network Load to the Transmission Providers total load computed in accordance with Section 34.2 of the Network Integration Transmission Service under Part III of the OATT.

1.17 Load Shedding

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations.

1.18 Long-Term Firm Point-to-Point Transmission Service

Firm Point-to-Point Transmission Service under Part II of the OATT with a term of one year or more.

1.19 Native Load Customers

The wholesale and retail power customers of the MECL on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission System to meet the reliable electric needs of such customers.

1.20 Network Customer

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the OATT.

1.21 Network Integration Transmission Service

The transmission service provided under Part III of the OATT.

1.22 Network Load

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the OATT. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the OATT for any Point-to-Point Transmission Service that may be necessary for such non-designated load.

1.23 Network Operating Agreement

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the OATT.

1.24 Network Resource

Any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

1.25 Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.26 Non-Dispatchable Generator

A generator that is subject to instantaneous or near-instantaneous limitation on its output by wind speed, river flows, or other non-controllable inputs.

1.27 Non-Firm Point-to-Point Transmission Service

Point-to-Point Transmission Service under the OATT that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this OATT. Non-Firm Point-to-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.27a Non-Firm Sale

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.28 Open Access Same-Time Information System (OASIS)

The information system and standards of conduct normally found on an OASIS will be provided on the MECL website until such time as MECL determines the need for an OASIS.

1.29 OATT

Open Access Transmission Tariff

1.30 Part I

OATT Definitions and Common Service Provisions contained in Sections 2 through 12.

1.31 Part II

OATT Sections 13 through 27 pertaining to Point-to-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Part III

OATT Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.33 Parties

The Transmission Provider and the Transmission Customer receiving service under the OATT.

1.34 Point(s) of Delivery

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II and Part III of the OATT. The Point(s) of Delivery shall be specified in the Service Agreement.

1.35 Point(s) of Receipt

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II and Part III of the OATT. The Point(s) of Receipt shall be specified in the Service Agreement.

1.36 Point-to-Point Transmission Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the OATT.

1.37 Power Purchaser

The entity that is purchasing the capacity and energy to be transmitted under the OATT.

1.37a Pre-Confirmed Application

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.38 Receiving Party

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.38a Regional Transmission Group (RTG)

A voluntary organization of transmission owners, transmission users and other entities formed to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.39 Reserved Capacity

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the OATT. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.40 Service Agreement

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the OATT.

1.41 Service Commencement Date

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the OATT.

1.42 Short-Term Firm Point-to-Point Transmission Service

Firm Point-to-Point Transmission Service under Part II of the OATT with a term of less than one year.

1.42a System Condition

A specified condition on the Transmission Provider's system or on a neighbouring system, such as a constrained transmission element or flowgate that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.43 System Impact Study

An assessment by the Transmission Provider of:

i. the adequacy of the Transmission System to accommodate a request for either Firm Point-to-Point Transmission Service or Network Integration Transmission Service; and

ii. whether any additional costs may be incurred in order to provide Transmission Service.

1.44 Third-Party Sale

Any sale for resale in interprovincial, interstate or international commerce to a Power Purchaser that is not designated as part of Network Load under the Network Service Integration Transmission Service.

1.45 Transmission Customer

Any Eligible Customer (or its Designated Agent) that:

i. executes a Service Agreement, or

ii. requests in writing that the Transmission Provider file with IRAC, a proposed unexecuted Service Agreement to receive Transmission Service under Part II or Part III of the OATT. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this OATT.

1.46 Transmission Provider

Maritime Electric Company, Limited (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy and capacity in interprovincial or interstate commerce and provides Transmission Service under the OATT.

1.47 Transmission Provider's Monthly Transmission System Peak

Not Applicable.

1.48 Transmission Service

Point-to-Point and Network Integration Transmission Service provided under Part II and Part III of the OATT on a firm and non-firm basis.

1.49 Transmission System

The facilities owned, controlled or operated by the Transmission Provider that are used to provide Transmission Service under Part II and Part III of the OATT.

1.50 Transmission System Users Group

A voluntary organization of Transmission Customers and other entities formed to provide non-binding recommendations to the Transmission Provider for improving Transmission Service. (See also Section 12.7)

2 INITIAL ALLOCATION AND RENEWAL PROCEDURES

2.1 Initial Allocation of Available Transmission Capability

(Revoked –No Longer Required)

2.2 Reservation Priority For Existing Firm Service Customers

Existing firm service customers with a contract term of five years or more, have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for Transmission Service, the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by IRAC, for such service, provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement.

This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Service agreements subject to a right of first refusal entered into prior to the date of the Transmission Provider’s filing of a revised tariff adopting the reformed rollover language herein, unless terminated, will become subject to the five year/one year requirement on the first rollover date after the date of that filing, provided that, the one-year notice requirement shall apply to all such service agreements with five years or more left in their terms.

2.3 Amendments

Subject to the approval of IRAC, the OATT may be amended as required. Nothing in the OATT or any Completed Application shall be construed as affecting in any way the right of the Transmission Provider to amend the OATT, including but not limited to a change in rates, charges and terms and conditions (including applicable rates) of Transmission Service. Transmission Customers shall take Transmission Service under the OATT as amended.

2.4 Replacement OATT

In the event that the OATT is replaced by a subsequent transmission OATT and subject to the approval of IRAC, Transmission Customers that have been receiving Transmission Service under the OATT shall take service under the terms and conditions (including applicable rates) of the replacement transmission OATT.

2.5 Legislation

The OATT is subject to legislation and regulations which govern the operations of the Transmission Provider and may be subject to change as such legislation or regulations evolve. Transactions arising from the OATT shall be governed by the laws of Prince Edward Island.

2.6 Reliability Compliance

All rights and obligations of the Transmission Provider and Transmission Customers receiving Transmission Service under the OATT shall be subject to the reliability guidelines and any amendments thereto issued by the Control Area Operator, or its successor.

3 ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the Transmission Service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services:

i. Scheduling, System Control and Dispatch, and

ii. Reactive Supply and Voltage Control from Generation or other Sources.

The Transmission Customer serving load is required to secure or self-supply in quantities determined by the Control Area Operator the following Ancillary Services:

i. Regulation and Frequency Response,

ii. Energy Imbalance,

iii. Operating Reserve - Spinning, and

iv. Operating Reserve – Supplemental

The Transmission Customer serving load is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may elect to:

- have the Transmission Provider act as its agent,
- secure Ancillary Services directly from the Control Area Operator, or
- secure the Ancillary Services (discussed in Schedules 3, 4, 5 and 6) from a third party or by self-supply when technically feasible. The Transmission Provider

shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the OATT. If the Transmission Provider offers an Eligible Customer a rate discount, or attributes a discounted Ancillary Service rate to its own transactions for Scheduling, System Control and Dispatch, Reactive Supply or Voltage Control from Generation Sources, the Transmission Provider must offer at the same time the same discounted Ancillary Service rate for these Ancillary Services to all Eligible Customers. Information regarding any discounted Ancillary Service rates must be posted on the MECL website pursuant to the following:

- Once details of a negotiated discount have been finalized (service, price, length of service) they must be posted immediately on the MECL website.
- Discounts may be limited to particular time periods.
- Discounts must apply for the same time period and must be offered to all Transmission Customers.
- The Transmission Provider may discount only if necessary to increase usage of the Ancillary Services or to reflect reduced cost of procurement to the Transmission Provider.

In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation Sources Service

The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service

Where applicable, the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service

Where applicable, the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve - Spinning Reserve Service

Where applicable, the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve - Supplemental Reserve Service

Where applicable, the rates and/or methodology are described in Schedule 6.

4 OPEN ACCESS SAME-TIME INFORMATION SYSTEM (OASIS)

Terms and conditions regarding Open Access Same-Time Information System are set forth in Attachment P and the Standards of Conduct including their Implementation Procedures are posted on MECL's OASIS and public web site. In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this OATT pursuant to Sections 19 and 32.

The Transmission Provider shall post on OASIS and its public website an electronic link to all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The Transmission Provider shall post on OASIS and on its public website an electronic link to the NAESB website where any rules, standards and practices that are protected by copyright may be obtained. The Transmission Provider shall also post on OASIS and its public website an electronic link to a statement of the process by which the Transmission Provider shall add, delete or otherwise modify the rules, standards and practices that are not included in this tariff. Such process shall set forth the means by which the Transmission Provider shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the Transmission Provider deems appropriate.

5 LOCAL FURNISHING BONDS (NOT USED AT THIS TIME)

6 RECIPROCITY

A Transmission Customer receiving Transmission Service under this OATT agrees to provide comparable Transmission Service to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy in interprovincial commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy and capacity or interprovincial commerce owned, controlled or operated by the Transmission Customer's corporate Affiliates. A Transmission Customer that is a member of, or takes transmission service from, a power pool, Regional Transmission Group, Independent System Operator, or other transmission organization also agrees to provide comparable transmission service to the transmission-owning members of such power pool, Regional Transmission Group, Independent System Operator, or other transmission organization, on similar terms and conditions over facilities used for the transmission of electric energy in interstate or interprovincial commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy in interstate or interprovincial commerce owned, controlled or operated by the Transmission Customer's Corporate Affiliates.

Similar to the safe harbour provision in Orders 888 and 889, when full regulatory approval within the jurisdiction of the system external to Prince Edward Island cannot be achieved in a timely manner or if the terms and conditions of the reciprocal Transmission Service offered by the operator of the external system are not considered to be comparable by the Transmission Provider, the operator of the external system may submit its Standards of Conduct and Open Access Transmission Tariff to IRAC for its review and approval relative to this reciprocity requirement and the ruling of IRAC shall prevail.

7 BILLING AND PAYMENT

7.1 Billing Procedure

Within five Business Days after the first day of each month, the Transmission Provider, or its Designated Agent, shall submit an invoice to the Transmission Customer for the charges for all services furnished under the OATT during the preceding month. Such charges shall be calculated using the current rates in effect.

The invoice is due and shall be paid by the Transmission Customer by the twentieth (20th) day of each month, or if the twentieth day of the month is a Saturday, Sunday or statutory holiday for either Party, the closest previous common working day to the twentieth day. Payments shall be made electronically to a bank named by the Transmission Provider. If the rendering of an invoice is unavoidably delayed, an interim invoice based on estimated charges may be issued by the Transmission Provider or its Designated Agent. Each invoice shall be subject to adjustment for any errors in calculations, meter readings, estimating or otherwise. Any such billing adjustments shall be made as promptly as practical, but in no event later than twelve (12) months after issuing the invoice.

7.2 Interest On Unpaid Balances

Any amounts not paid by the due date, including amounts placed in escrow pursuant to Section 7.3, shall be subject to interest, calculated on a daily basis, from the due date to the date of payment, at an interest rate equal to the sum of (a) the prime rate per annum as charged by the RBC Royal Bank, Queen Street Branch, Charlottetown, Prince Edward Island, or any other bank designated by the Transmission Provider or its Designated Agent, on the last banking day of the month for which payment is due; and (b) five percent per annum.

7.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to remedy such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may suspend Transmission Service without further notice. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend Transmission Service seven (7) calendar days following such notice.

8 ACCOUNTING FOR THE TRANSMISSION PROVIDER'S USE OF THE OATT

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues

Include in a separate operating revenue account or sub account the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the OATT.

8.2 Study Costs and Revenues

Include in a separate transmission operating expense account or sub account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if construction of new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the OATT, or others' uses; and include in a separate operating revenue account or sub account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the OATT.

9 REGULATORY FILINGS AND CHANGE IN LAW, REGULATION, RULE OR PRACTICE

9.1 Regulator Filings

Nothing contained in the OATT or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to IRAC for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under the Electric Power Act and pursuant to the IRAC's rules and regulations promulgated thereunder. Nothing contained in the OATT or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the OATT to exercise its rights under the Electric Power Act and pursuant to IRAC's rules and regulations promulgated thereunder.

9.2 Change in Law, Regulation, Rule or Practice

If the Province, IRAC or Maritime Electric implements a change in any law, regulation, rule or practice; which change affects or is reasonably expected to affect the provision of Transmission Service to Customer pursuant to agreements arising from this OATT, the parties agree to negotiate in good faith to determine the amendments, if any, to those agreements arising from this OATT reasonably necessary to conform the terms of Transmission Service to such change, and where practicable will provide Customer with thirty (30) days advance notice; provided that if the Parties are unable to reach agreement as to what, if any, amendments are necessary, Customer will have the right to oppose such filing and participate fully in any proceeding established by IRAC to address such amendment.

10 FORCE MAJEURE AND INDEMNIFICATION

10.1 Force Majeure

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this OATT if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this OATT is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this OATT.

10.2 Indemnification

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, legal fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this OATT on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 CREDITWORTHINESS

The Transmission Provider has specified its Creditworthiness Procedures in Attachment O.

12 DISPUTE RESOLUTION PROCEDURES

12.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and the Transmission Provider involving Transmission Service under the OATT (excluding applications for rate changes or other changes to the OATT, or to any Service Agreement entered into under the OATT, which shall be presented directly to IRAC for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) Business Days (or such other period as the Parties may agree upon) by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures

Any arbitration initiated under the OATT shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Business Days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Business Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Arbitration Act of Prince Edward Island and any applicable IRAC regulations.

12.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the OATT and any Service Agreement entered into under the OATT and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Arbitration Act of Prince Edward Island.

12.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

a. the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

b. one half the cost of the single arbitrator jointly chosen by the Parties.

In the event that it is necessary to enforce such award, all costs of enforcement shall be payable and paid by the Party against whom such award is enforced.

12.5 Referral of Dispute to IRAC

Notwithstanding anything contained in this Section 12, either party may:

a. instead of proceeding through the External Arbitration Procedures outlined in Sections 12.2 to 12.4 above, elect to refer a dispute directly to IRAC by filing a complaint with IRAC in the manner set out below and the decision of IRAC with respect to the matter shall be final and binding and the matter in dispute cannot thereafter proceed to the dispute resolution process; or

b. if either party is dissatisfied with the results of an arbitration decision rendered pursuant to Section 12.3, refer a complaint to IRAC for determination and the decision of IRAC with respect to the matter shall be final and binding.

Complaints filed with IRAC must be in writing and must include reasons and evidence in support of the dissatisfied party's position. A copy of the complaint, together with the supporting reasons and evidence, must be filed with the other party.

IRAC may require a complainant to provide such security for the costs incurred or to be incurred by IRAC, as it considers reasonable, and such security may be forfeited to IRAC if the complaint is not substantiated.

12.6 Enforcement of Arbitration Decision

The Arbitration Act of Prince Edward Island shall govern the procedures to apply in the enforcement of any award made pursuant to Section 12.3.

12.7 Transmission System Users Group

The Transmission System Users Group consists of one representative from each Eligible Customer, each transmission connected generator, the Control Area Operator and the Transmission Provider. The Transmission System Users Group shall advise the Transmission Provider on issues related to the OATT including Transmission Planning as set out in Attachment K.

II. POINT-TO-POINT TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-to-Point Transmission Service pursuant to the applicable terms and conditions of this OATT. Point-to-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

13 NATURE OF FIRM POINT-TO-POINT TRANSMISSION SERVICE

13.1 Term

The minimum term of Firm Point-to-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority

Long-Term Firm Point-to-Point Transmission Service shall be available on a first-come, first-served basis i.e., in the chronological sequence in which each Transmission Customer has requested service.

Reservations for Short-Term Firm Point-to-Point Transmission Service will be conditional based upon the length of the requested transaction or reservation. However, Pre-Confirmed Applications for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among requests or reservations with the same duration and, as relevant, pre-confirmation status (pre-confirmed, confirmed, or not confirmed), priority will be given to an Eligible Customer's request or reservation that offers the highest price, followed by the date and time of the request or reservation.

If the Transmission System becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines; one Business Day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Short-Term Firm Point-to-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration reservations shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the OATT.

Firm Point-to-Point Transmission Service will always have a reservation priority over Non-Firm Point-to-Point Transmission Service under the OATT. All Long-Term Firm Point-to-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the OATT when making Third-Party Sales. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-to-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements

The Transmission Provider shall offer a standard form Firm Point-to-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-to-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-to-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-to-Point Transmission Service pursuant to the OATT. Executed Service Agreements that contain the information required under the OATT shall be filed with IRAC. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Transmission Provider shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, the Transmission Provider shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

13.5 Transmission Customer Obligations for Facility Additions or Re-dispatch Costs

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-to-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-to-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by re-dispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of re-dispatch requirements as described in Section 15.4. Any re-dispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer under the OATT will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the system directly and indirectly interconnected with the Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Native Load Customers, Network Customers and Transmission Customers taking Firm Point-to-Point Transmission Service on a similar basis. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-to-

Point Transmission Service shall be subordinate to Firm Transmission Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed with secondary service (as defined in Section 28.4) in cases where the conditions apply but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the OATT when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service

a. The Transmission Customer taking Firm Point-to-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

b. The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

c. The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-to-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-to-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (See Section 13.9).

13.8 Scheduling of Firm Point-to-Point Transmission Service

Schedules for the Transmission Customer's Firm Point-to-Point Transmission Service must be submitted to the Transmission Provider no later than 9:00 a.m. Atlantic Time of the Business Day prior to commencement of such service. Schedules submitted after 9:00 a.m. Atlantic Time will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of

1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to thirty (30) minutes before the start of the next scheduling interval provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

13.9 Rate Treatment for Exceeding Capacity Reservation

A Transmission Customer may not exceed its Firm capacity reservation at the Point of Receipt and the Point of Delivery. In the event that the reserved capacity at the Point of Receipt or the Point of Delivery is exceeded, the Transmission Customer shall pay 110% of the charge for the On-Peak or Off-Peak Hourly Firm Point-to-Point Transmission Service based on the time of the excess, including Schedules 1 and 2 Ancillary Services. During periods when the Transmission System is constrained, the Transmission Customer shall pay 150% of the charge for the On-Peak or Off-Peak Hourly Non-Firm Point-to-Point Transmission Service based on the time of the excess, including Schedules 1 and 2 Ancillary Services.

14 NATURE OF NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

14.1 Term

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority

Non-Firm Point-to-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-to-Point Transmission Service. A higher priority will be assigned first to requests or reservations with a longer duration of service and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term request or reservation for Firm Point-to-Point Transmission Service before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within the time limits indicated by the Transmission Provider's published practices. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-to-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the OATT.

14.3 Use of Non-Firm Point-to-Point Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the OATT when making Third-Party Sales. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-to-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements

The Transmission Provider shall offer a standard Form for Non-Firm Point-to-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-to-Point Transmission Service pursuant to the OATT. Executed Service Agreements that contain the information required under the OATT shall be filed with IRAC.

14.5 Classification of Non-Firm Point-to-Point Transmission Service

Non-Firm Point-to-Point Transmission Service shall be offered under terms and conditions contained in Part II of the OATT. The Transmission Provider undertakes no obligation under the OATT to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-to-Point Transmission Service. Parties requesting Non-Firm Point-to-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the OATT. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation (See Section 14.8). Non-Firm Point-to-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-to-Point Transmission Service

Schedules for Non-Firm Point-to-Point Transmission Service must be submitted to the Transmission Provider no later than 9:00 a.m. Atlantic Time of the Business Day prior to commencement of such service. Schedules submitted after 9:00 a.m. Atlantic Time will be accommodated, if practicable. Hour-to-hour and Intra-Hour (four intervals consisting of fifteen minute schedules) schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission

Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to thirty (30) minutes before the start of the next scheduling interval provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-to-Point Transmission Service provided under the OATT for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-to-Point Transmission Service provided under the OATT for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-to-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-to-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources, or (5) transmission service for Firm Point-to-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-to-Point Transmission Service shall be subordinate to Firm Transmission

Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-to-Point Transmission Service under the Tariff. Non-Firm Point-to-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-to-Point Transmission Service under the OATT. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

14.8 Rate Treatment for Exceeding Capacity Reservation

A Transmission Customer may not exceed its Non-Firm capacity reservation at the Point of Receipt and the Point of Delivery. In the event that the reserved capacity at the Point of Receipt or the Point of Delivery is exceeded, the Transmission Customer shall pay 110% of the charge for the On-Peak or Off-Peak Hourly Non-Firm Point-to-Point Transmission Service based on the time of the excess, including Schedules 1 and 2 Ancillary Services. During periods when the Transmission System is constrained, the Transmission Customer shall pay 150% of the charge for the On-Peak or Off-Peak Hourly Non-Firm Point-to-Point Transmission Service based on the time of the excess, including Schedules 1 and 2 Ancillary Services.

15 SERVICE AVAILABILITY

15.1 General Conditions

The Transmission Provider will provide Firm and Non-Firm Point-to-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability

A description of the Transmission Provider's specific methodology for assessing available transfer capability is contained in Attachment C of the OATT. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-to-Point Transmission Service cannot agree on all the terms and conditions of the Point-to-Point Service Agreement, the Transmission Provider shall file with IRAC, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-to-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate IRAC ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the OATT including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System, Re-dispatch or Conditional Curtailment

a. If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-to-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use commercially reasonable efforts to expand or modify its Transmission System to provide the requested Firm Transmission Service consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

b. The Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to provide re-dispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the re-dispatch, or (iii) the Transmission Customer terminates the service because of re-dispatch changes resulting from the reassessment. A Transmission Provider shall not unreasonably deny self-provided re-dispatch or re-dispatch arranged by the Transmission Customer from a third party resource.

c. If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, the Transmission Provider will use due diligence to provide the service until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

15.5 Deferral of Service

The Transmission Provider may defer providing service until completion of construction of new transmission facilities or upgrades needed to provide Firm Point-to-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission 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 on the Maritime Electric website.

16 TRANSMISSION CUSTOMER RESPONSIBILITIES

16.1 Conditions Required of Transmission Customers

Point-to-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

a. The Transmission Customer has pending a Completed Application for service;

b. The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

c. The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the OATT commences;

d. The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the OATT, whether or not the Transmission Customer takes service for the full term of its reservation;

e. The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

f. The Transmission Customer has executed a Point-to-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the OATT on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 PROCEDURES FOR ARRANGING FIRM POINT-TO-POINT TRANSMISSION SERVICE

17.1 Application

A request for Firm Point-to-Point Transmission Service for periods of one year or longer must contain a written Application (Attachment A: Form For Service Agreement for Firm Point-to-Point Transmission Service) to: Energy Control Centre, Maritime Electric Company, Limited, P.O. Box 1328, 180 Kent Street, Canada, C1A 7N2, at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. Submission of an enabling agreement (Attachment A: Form For Service Agreement for Firm Point-to-Point Transmission Service) must precede or accompany a Transmission Customer's first request for Short-Term Firm Transmission Service. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax or email, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application

A Completed Application shall provide all of the required information including but not limited to the following:

i. The identity, address, telephone number and facsimile number of the entity requesting service;

ii. A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the OATT;

iii. The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

iv. The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this OATT, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the approved standards of conduct;

v. A description of the supply characteristics of the capacity and energy to be delivered;

vi. An estimate of the capacity and energy expected to be delivered to the Receiving Party;

vii. The Service Commencement Date and the term of the requested Transmission Service;

viii. The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

ix. A statement indicating that, if the Eligible Customer submits a Pre- Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service; and

x. Any additional information required by the Transmission Provider's planning process established in Attachment K.

The Transmission Provider shall treat this information consistent with the Standards of Conduct as posted on the OASIS.

17.3 Deposit

A Completed Application for Firm Point-to-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-to-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service

Agreement for Firm Point-to-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-to-Point Transmission Service. Applicable interest shall be calculated on a daily basis, at an interest rate equal to the prime rate per annum as charged by the RBC Royal Bank, Queen Street Branch in Charlottetown, or any other bank designated by the Transmission Provider or its Designated Agent, on the last banking day of the month for which payment is due, calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application

If an Application fails to meet the requirements of the OATT, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the OATT, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-to-Point Transmission Service, the Transmission Provider shall make a determination of available transfer capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practicable to all completed applications (including applications for its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service

The Transmission Customer can obtain, subject to availability, up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof within 15 days of notifying the Transmission Provider it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-to-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 PROCEDURES FOR ARRANGING NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

18.1 Application

Eligible Customers seeking Non-Firm Point-to-Point Transmission Service must submit a Completed Application (Attachment B: Form For Service Agreement for Non-Firm Point-to-Point Transmission Service) to the Transmission Provider prior to or accompanying the first request for Non-Firm Transmission Service.

18.2 Completed Application

A Completed Application shall provide all of the required information including but not limited to the following:

i. The identity, address, telephone number and facsimile number of the entity requesting service;

ii. A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the OATT;

iii. The Point(s) of Receipt and the Point(s) of Delivery;

iv. The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

v. The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

vi. The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

vii. The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this OATT, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the approved Standards of Conduct which are provided on the Transmission Providers OASIS web site.

viii. A statement indicating that, if the Eligible Customer submits a Pre-Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

18.3 Reservation of Non-Firm Point-to-Point Transmission Service

Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) Business Days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the Business Day before service is to commence. Requests for service received later than 12:00 p.m. (Atlantic) of the Business Day prior to the day service is scheduled to commence will be accommodated if practicable.

18.4 Determination of Available Transfer Capability

Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service:

i. thirty (30) minutes for hourly service,

ii. sixty (60) minutes for daily service,

iii. four (4) hours for weekly service, and

iv. two (2) days for monthly service.

19 ADDITIONAL STUDY PROCEDURES FOR FIRM POINT-TO-POINT TRANSMISSION SERVICE REQUESTS

19.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. Once informed, the Eligible Customer shall immediately notify the Transmission Provider if it elects to have the Transmission Provider study re-dispatch or conditional curtailment as part of the System Impact Study. If notification is provided prior to tender of the System Impact Study Agreement, the Eligible Customer can avoid the costs associated with the study of these options. The Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact

Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement

i. The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

ii. If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

iii. For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

19.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use commercially reasonable efforts to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify:

1. any system constraints, identified with specificity by transmission element or flowgate,

2. re-dispatch options (when requested by an Eligible Customer) including an estimate of the cost of re-dispatch,

3. conditional curtailment options (when requested by an Eligible Customer) including the number of hours per year and the System Conditions during which conditional curtailment may occur, and

4. additional Direct Assignment Facilities or Network Upgrades required to provide the requested service.

For customers requesting the study of re-dispatch options, the System Impact Study shall:

1. identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and

2. provide a measurement of each resource's impact on the system constraint.

If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same commercially reasonable efforts in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use commercially reasonable efforts to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II and Attachment K of the OATT, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the Eligible Customer’s share of the costs of new facilities or upgrades. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the OATT.

19.6 Completing New Facilities

The Transmission Provider shall use commercially reasonable efforts to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-to-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service

If the Transmission Provider determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-to-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-to-Point Transmission Service that can be accommodated without addition of any facilities and through re-dispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-to-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the OATT. In order to exercise this option, the Eligible Customer shall request in writing an Expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the OATT. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

19.9 Failure to Meet Study Deadlines

Sections 19.3 and 19.4 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

i. The Transmission Provider is required to file a notice with IRAC in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the Transmission Provider in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

ii. For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the Transmission Provider shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies.

The Transmission Provider may provide an explanation in its notification filing to IRAC if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

20 PROCEDURES IF THE TRANSMISSION PROVIDER IS UNABLE TO COMPLETE NEW TRANSMISSION FACILITIES FOR FIRM POINT-TO-POINT TRANSMISSION SERVICE

20.1 Delays in Construction of New Facilities

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the

Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions

When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-to-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-to-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-to-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12.

20.3 Refund Obligation for Unfinished Facility Additions

If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the OATT, the obligation to provide the requested Firm Point-to-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest calculated on a daily basis, at an interest rate equal to the prime rate per annum as charged by the RBC Royal Bank, Queen Street Branch in Charlottetown, or any other bank designated by the Transmission

Provider or its Designated Agent, on the last banking day of the month for which payment is due. However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 PROVISIONS RELATING TO TRANSMISSION CONSTRUCTION AND SERVICES ON THE SYSTEMS OF OTHER UTILITIES

21.1 Responsibility for Third-Party System Additions

The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the OATT, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of new Transmission System facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission

Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12.

22 CHANGES IN SERVICE SPECIFICATIONS

22.1 Modifications on a Non-Firm Basis

The Transmission Customer taking Firm Point-to-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-to-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

a. Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the OATT or by the Transmission Provider on behalf of its Native Load Customers.

b. The sum of all Firm and Non-Firm Point-to-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

c. The Transmission Customer shall retain its right to schedule Firm Point-to-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

d. Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-to-Point Transmission Service under the OATT. However, all other requirements of Part II of the OATT (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification on a Firm Basis

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 thereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 SALE OR ASSIGNMENT OF TRANSMISSION SERVICE

23.1 Procedures for Assignment or Transfer of Service

A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute a service agreement with the Transmission Provider governing reassignments of transmission service prior to the date on which the reassigned service commences. Such service agreement is to utilize the form set out in Attachment A-1 Form of Service Agreement For The Resale, Reassignment Or Transfer Of Point-To-Point Transmission Service**.** The Transmission Provider shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Transmission Provider or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this OATT. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the OATT, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Transmission Provider and the Reseller through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service

In accordance with Section 4, all sales or assignments of capacity must be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the reassigned service commences and is subject to Section 23.1. Resellers may also use the Transmission Provider's website to post transmission capacity available for resale.

24 METERING AND POWER FACTOR CORRECTION AT RECEIPT AND DELIVERY POINT(S)

24.1 Transmission Customer Obligations

Unless otherwise agreed, the Transmission Provider shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the OATT and to communicate the information as required. Such equipment shall remain the property of the Transmission Provider. At the Point of Receipt, the Transmission Customer will pay the associated costs. At the Point of Delivery, the Transmission Provider will pay the associated costs.

24.2 Transmission Provider Access to Metering Data

The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor at the Point of Delivery within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

In lieu of any specific power factor requirements in the relevant Service Agreement, the penalty for poor power factor in any month shall be charged at a rate of four (4) times the monthly firm rate for transmission service applied to the following:

	90% of the maximum MVA measured in the month
Less	the maximum transmission billing demand in MW

The monthly rate for transmission service is the monthly firm Point-to-Point rate as noted in Schedule 7 and is not to include the rate for any ancillary services.

25 COMPENSATION FOR TRANSMISSION SERVICE

Rates for Firm and Non-Firm Point-to-Point Transmission Service are provided in the Schedules appended to the OATT: Firm Point-to-Point Transmission Service (Schedule 7); and Non-Firm Point-to-Point Transmission Service (Schedule 8).

The Transmission Provider shall use Part II of the OATT to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable OATT rates, pursuant to Section 8.

26 STRANDED COST RECOVERY

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this OATT. However, the Transmission Provider must separately file any specific proposed stranded cost charge with IRAC.

27 COMPENSATION FOR NEW FACILITIES AND RE-DISPATCH COSTS

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-to-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with the Transmission Provider's policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved by re-dispatching the Transmission Provider's resources or others' resources to eliminate such constraints, the Transmission Customer shall be responsible for the re-dispatch costs to the extent consistent with the Transmission Provider's policy.

III. NETWORK INTEGRATION TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the OATT and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve other Network Loads and any Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the OATT.

28 NATURE OF NETWORK INTEGRATION TRANSMISSION SERVICE

28.1 Scope of Service

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the OATT. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities

The Transmission Provider will plan, operate and cause to be constructed and maintained the Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network

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 system average losses. The system average loss factor 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 under Part III of the OATT, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, and (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the OATT or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with IRAC.

29.2 Application Procedures

An Eligible Customer requesting service under Part III of the OATT must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below to: Energy Control Centre, Maritime Electric Company, Limited, 180 Kent Street, PO Box 1328, Charlottetown, PE, C1A 7N2. The Transmission Provider will time-stamp the submittal as a record for establishing the service priority of the Application. A Completed Application shall provide all of the information including but not limited to the following:

i. The identity, address, telephone number and facsimile number of the party requesting service;

ii. A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the OATT;

iii. A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

iv. The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

v. A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

a. Unit size and amount of capacity from that unit to be designated as Network Resource,

b. VAR capability (both leading and lagging) of all generators,

c. Operating restrictions,

i. Any periods of restricted operations throughout the year,

ii. Maintenance schedules,

iii. Minimum loading level of unit,

iv. Normal operating level of unit,

v. Any must-run unit designations required for system reliability or contract reasons,

d. Approximate variable generating cost ($/MWH) for re-dispatch computations, and

e. Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource.

For each off-system Network Resource, such description shall include:

a. Identification of the Network Resource as an off-system resource;
b. Amount of power to which the customer has rights;
c. Identification of the control area from which the power will originate;
d. Delivery point(s) to the Transmission Provider's Transmission System;
e. Transmission arrangements on the external transmission system(s);
f. Operating restrictions, if any;
    i. Any periods of restricted operations throughout the year
    ii. Maintenance schedules
    iii. Minimum loading level of unit
    iv. Normal operating level of unit
    v. Any must-run unit designations required for system reliability or contract reasons
g. Approximate variable generating cost ($/MWH) for re-dispatch computations.

vi. Description of Eligible Customer's transmission system:
  a. Load flow and stability data such as,
      i. real and reactive parts of the load,
      ii. lines,
      iii. transformers,
      iv. reactive devices and load type,
  b. normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider,
  c. operating restrictions needed for reliability operating guides employed by system operators,
  d. contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources Location of Network Resources described in subsection (v)

above,

e. 10 year projection of system expansions or upgrades Transmission System maps that include any proposed expansions or upgrades, and

f. thermal ratings of Eligible Customer's Control Area ties with other Control Areas.

vii. Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is five years.

viii. A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program; and

ix. Any additional information required of the Transmission Customer as specified in the Transmission Provider's planning process established in Attachment K.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the approved standards of conduct.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to ensure completion of such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement

The Transmission Provider will submit a copy of the Service Agreement to IRAC.

30 NETWORK RESOURCES

30.1 Designation of Network Resources

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the OATT. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made to the Transmission Provider by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. The Network Customer’s request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider as soon as reasonably practicable but not later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status must be submitted to the Transmission Provider, and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

i. Effective date and time of temporary termination;

ii. Effective date and time of redesignation, following period of temporary termination;

iii. Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

iv. Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2; and

v. Identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related transmission service requests must be approved or denied as a single request. The evaluation of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm sales delivered pursuant to Part II of the OATT, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

30.5 Network Customer Re-dispatch Obligation

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to re-dispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the re-dispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected with the Transmission Provider

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the OATT.

30.8 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's load.

30.9 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the Service Commencement Date under Part III of the OATT, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's annual transmission revenue requirement for Network Service. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 DESIGNATION OF NETWORK LOAD

31.1 Network Load

The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected with the Transmission Provider

The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use commercially reasonable efforts to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with the Transmission Expansion Policy sections of Attachment K.

31.3 Network Load Not Physically Interconnected with the Transmission Provider

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the OATT and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-to-Point Transmission Service under Part II of the OATT. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points

To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates

The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the OATT including, but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment K. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 ADDITIONAL STUDY PROCEDURES FOR NETWORK INTEGRATION TRANSMISSION SERVICE REQUESTS

32.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement

i. The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

ii. If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

iii. For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use commercially reasonable efforts to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify:

1. any system constraints identified with specificity by transmission element or flowgate,
2. re-dispatch options (when requested by an Eligible Customer) including, to the

extent possible, an estimate of the cost of re-dispatch,

3. available options for installation of automatic devices to curtail service (when requested by an Eligible Customer), and
4. additional Direct Assignment Facilities or Network Upgrades required to provide the requested service.

For customers requesting the study of re-dispatch options, the System Impact Study shall:

1. identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint; and
2. provide a measurement of each resource's impact on the system constraint.

If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same commercially reasonable efforts in completing the System Impact Study for all Eligible Customers. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement with IRAC, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use commercially reasonable efforts to complete the required Facilities Study within a sixty (60) day period, or as otherwise agreed to with the Network Customer. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of:

i. the cost of Direct Assignment Facilities to be charged to the Eligible Customer,

ii. the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and

iii. the time required to complete such construction and initiate the requested service.

As soon as the Facilities Study is complete, the Transmission Provider shall make a copy of the completed Facilities Study available and tender a Service Agreement to the Eligible Customer. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the Eligible Customer’s share of the costs of new facilities or upgrades. After being tendered with a Service Agreement, the Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement with IRAC and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

32.5 Failure to Meet Study Deadlines

Section 19.9 outlines the Transmission Provider's actions that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Part II of the OATT. These same requirements apply to service under Part III of the OATT.

33 LOAD SHEDDING AND CURTAILMENTS

33.1 Procedures

Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by re-dispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to re-dispatch all resources available to the Transmission Provider for re-dispatch including Network Resources on a least-cost basis without regard to the ownership of such resources. Any re-dispatch under this section may not unduly discriminate between Maritime Electric's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints

Whenever the Transmission Provider implements least-cost re-dispatch procedures in response to a transmission constraint, the Network Customers will each bear a proportionate share of the total re-dispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries

If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost re-dispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement.

33.5 Allocation of Curtailments

The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by Network Customers in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for Network Customers to shed load, the Network Customers shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability

Notwithstanding any other provisions of this OATT, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to:

i. limit the extent or damage of the adverse condition(s) or disturbance(s),
ii. prevent damage to generating or transmission facilities, or
iii. expedite restoration of service.

The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to Maritime Electric's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 RATES AND CHARGES

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with the Transmission Provider's policy as approved by IRAC, along with the following:

34.1 Network Integration Transmission Service Rate

The Network Customer shall pay a monthly Demand Charge as specified in Attachment H.

34.2 Determination of Network Customer's Monthly Network Load

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 load 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.

For greater clarity, the dispatch of Designated or Non-Designated Resources shall not be used to reduce the Network Customer's Monthly Network Load for billing purposes.

34.3 Determination of Transmission Provider's Monthly Transmission System Load

Not Applicable.

34.4 Re-dispatch Charge

The Network Customer shall pay a Load Ratio Share of any re-dispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for re-dispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this OATT. However, the Transmission Provider must separately file any proposal to recover stranded costs with IRAC.

34.6 Power Factor

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the range established by the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

In lieu of any specific power factor requirements in the relevant service agreement, the penalty for poor power factor in any month shall be charged at a rate of four (4) times the monthly firm rate for transmission service applied to the following:

90% of the maximum kVA measured in the month
Less
maximum transmission billing demand in kW

The monthly rate for Network Integration is the monthly rate as noted in Attachment H and is not to include the rate for any ancillary services.

35 OPERATING ARRANGEMENTS

35.1 Operation Under the Network Operating Agreement

The Network Customer and facility owner shall plan, construct, operate and maintain the facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement

The terms and conditions under which the Network Customer and facility owner shall operate the facilities and the technical and operational matters associated with the implementation of Part III of the OATT shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the facility owner and the Network Customer to:

i. operate and maintain equipment necessary for integrating the facilities within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment),

ii. transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for re-dispatch required under Section 33, voltage schedules, loss factors and other real time data),

iii. use software programs required for data links and constraint dispatching,

iv. exchange data on forecasted loads and resources necessary for long-term planning, and

v. address any other technical and operational considerations required for implementation of Part III of the OATT, including scheduling protocols.

The Network Operating Agreement will recognize that the Network Customer shall:

i. satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider or the Control Area Operator, or

ii. satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the Control Area Operator or its successor requirements.

The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement shall be substantially in the form as specified in Attachment G.

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$1,148.45/MW of Reserved Capacity per year.
2.	Monthly Delivery:	C$95.70/MW of Reserved Capacity per month.
3.	Weekly Delivery:	C$22.09/MW of Reserved Capacity per week.
4.	On-Peak Daily Delivery:	C$4.42/MW of Reserved Capacity per day.
5.	Off-Peak Daily Delivery:	C$3.15/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$95.70/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 Generation 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 Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider. Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (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$1,535.61/MW of Reserved Capacity per year.
2. Monthly Delivery:	C$127.97/MW of Reserved Capacity per month.
3. Weekly Delivery:	C$29.53/MW of Reserved Capacity per week.
4. On-Peak Daily Delivery:	C$5.91/MW of Reserved Capacity per day.
5. Off-Peak Daily Delivery:	C$4.21/MW of Reserved Capacity per day.
6. On-Peak Hourly Delivery:	C$0.37/MW of Reserved Capacity per hour.
7. Off-Peak Hourly Delivery:	C$0.18/MW of Reserved Capacity per hour.

Network Integration	C$127.97/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 collaberation 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.

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.

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.

[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.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (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$30,522.91/MW of Reserved Capacity per year.

2. Monthly Delivery: C$2,543.58/MW of Reserved Capacity per month.

3. Weekly Delivery C$586.98/MW of Reserved Capacity per week.

4. On-Peak Daily Delivery: C$117.40/MW of Reserved Capacity per day.

5. Off-Peak Daily Delivery: C$83.62/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$2,543.58/MW of Reserved Capacity per month.

2. Weekly delivery: C$586.98/MW of Reserved Capacity per week.

3. On-Peak Daily delivery: C$117.40/MW of Reserved Capacity per week.

4. Off-Peak Daily delivery: C$83.62/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$7.34/MW of Reserved Capacity per hour.

6. Off-Peak Hourly delivery: C$3.48/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.

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 the Transmission Provider's rules.

ATTACHMENT A

Form of Service Agreement for Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between Maritime Electric Company, Limited (Transmission Provider), and ____________ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the OATT.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in the amount of $_________, in accordance with the provisions of Section 17.3 of the OATT.

4.0 Service under this agreement shall commence on the later of (1) __________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by IRAC. Service under this agreement shall terminate on _____________________ or other such date as mutually agreed upon by the Parties.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Company Name:	Maritime Electric Company, Limited
Billing Contact:	OATT Administrator
Address:	PO Box 1328, 180 Kent Street
	Charlottetown PE C1A 7N2
Telephone:	1-800-670-1012
Fax:	902-629-3665
Email:	OATTAdministrator@MaritimeElectric.com

Transmission Customer:

Company Name:	______________________________
Billing Contact:	______________________________
Address:	______________________________
	______________________________
Telephone:	______________________________
Fax:	______________________________
Email:	______________________________

Administrative:

Contact: ______________________________

Address: ______________________________

____

Telephone: ______________________________

Fax: ______________________________

Email: ______________________________

7.0 The OATT is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ______________________________

Name:

Title: Vice President, Corporate Planning and Energy Supply

Date: ______________________________

Transmission Customer:

By: ______________________________

Name: ______________________________

Title: ______________________________

Date: ______________________________

Specifications for Long-Term Firm Point-To-Point

Transmission Service

1.0 Term of Transaction: ______________________________
Start Date: ______________________________
Termination Date: ______________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ______________________________
Delivering Party: ______________________________
Capacity Reservation at Point(s) of Receipt: ____________________

____

4.0 Point(s) of Delivery: ______________________________
Receiving Party: ______________________________
Capacity Reservation at Point(s) of Delivery: ____________________

____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

____

6.0 Designation of party(ies) subject to reciprocal service obligation:

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service:

____

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the OATT.

8.1 Transmission Charge: ____

____

8.2 System Impact and/or Facilities Study Charge(s): ____________________

____

8.3 Direct Assignment Facilities Charge: ______________________________

____

8.4 Ancillary Services Charges: ______________________________________

____

____

____

ATTACHMENT A-1

Form of Service Agreement for The Resale, Reassignment or Transfer of Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between _____________ (the Transmission Provider), and ________________ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section 23.1of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Company Name:	Maritime Electric Company, Limited
Billing Contact:	OATT Administrator
Address:	PO Box 1328, 180 Kent Street
	Charlottetown PE C1A 7N2
Telephone:	1-800-670-1012
Fax:	902-629-3665
Email:	OATTAdministrator@MaritimeElectric.com

Assignee:

Company Name:	____________________________________
Billing Contact:	____________________________________
Address:	____________________________________
	____________________________________
Telephone:	____________________________________
Fax:	____________________________________
Email:	____________________________________

Administrative:

Contact: ______________________________

Address: ______________________________

____

Telephone: ______________________________

Fax: ______________________________

Email: ______________________________

6.0 The OATT is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ______________________________ ______________________________

Name Title

____

Date

Assignee:

By: ______________________________ ______________________________

Name Title

____

Date

Specifications for the Resale, Reassignment or Transfer of Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ______________________________

Start Date: ______________________________

Termination Date: ______________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ______________________________

Delivering Party: ______________________________

4.0 Point(s) of Delivery: ______________________________

Receiving Party: ______________________________

5.0 Maximum amount of reassigned capacity: ____________________

6.0 Designation of party(ies) subject to reciprocal service obligation:

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service:

____

____

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the OATT.)

8.1 Transmission Charge:

____

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges:

____

____

____

____

9.0 Name of Reseller of the reassigned transmission capacity:

____

ATTACHMENT B

Form of Service Agreement For Non-Firm Point-to-Point Transmission Service

Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between Maritime Electric Company, Limited (Transmission Provider), and _____________ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the OATT and has filed a Completed Application for Non-Firm Point-to-Point Transmission Service in accordance with Section 18.2 of the OATT.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Company Name:	Maritime Electric Company, Limited
Billing Contact:	OATT Administrator
Address:	PO Box 1328, 180 Kent Street
	Charlottetown PE C1A 7N2
Telephone:	1-800-670-1012
Fax:	902-629-3665
Email:	OATTAdministrator@MaritimeElectric.com

Transmission Customer:

Company Name:	____
Billing Contact:	____
Address:	____
	____
Telephone:	____
Fax:	____
Email:	____

Administrative:

Contact: ______________________________

Address: ______________________________

____

Telephone: ______________________________

Fax: ______________________________

Email: ______________________________

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ______________________________

Name: ______________________________

Title: Vice President, Corporate Planning and Energy Supply

Date: ______________________________

Transmission Customer:

By: ______________________________

Name: ______________________________

Title: ______________________________

Date: ______________________________

ATTACHMENT C

Methodology to Assess Available Transfer Capability

The Transmission Provider is responsible for calculating the Total Transfer Capabilities (TTCs) and Available Transfer Capabilities (ATCs) for the interface between the Transmission Provider's (Maritime Electric) Transmission System and the transmission system of its neighboring utility (NB Power). This determination is to be done in coordination with NB Power TSO so there is agreement on the resulting TTC and ATC in each direction for the interface.

It is necessary that the methodologies used by the Transmission Provider for determining TTCs and ATCs are in compliance with the following NERC reliability standards as implemented by the Control Area Operator (NB Power TSO):

- MOD-001-1a Available Transmission System Capability
- MOD-004-1 Capacity Benefit Margin
- MOD-008-1 TRM Calculation Methodology
- MOD-029-1a Rated System Path Methodology

As required by MOD-001-1a and MOD-029-1a, the Transmission Provider is responsible for:

- Establishing and maintaining an Available Transfer Capability Implementation Document (ATCID) to describe the methodology used for determining required TTC and ATC values.
- Making the ATCID document available to neighbouring entities and utilities that the Transmission Provider coordinates TTC and ATC activities with.
- Providing notification to neighbouring entities and utilities prior to implementation of a new or revised ATCID.

The Transmission Provider posts its TTC and ATC values in accordance with its OASIS Terms and Conditions (Attachment P).

ATTACHMENT D

Methodology for Completing a System Impact Study

Scope

A System Impact Study may be performed by the Transmission Provider to determine whether the Transmission Service requested by an Eligible Customer can be accommodated using the existing Transmission System. The study will identify any system constraints or impairments that would likely occur on the Transmission System and any re-dispatch options, within Prince Edward Island, which may be available to accommodate the requested service. The study may examine potential constraints in the Maritime Control Area. The System Impact Study would be performed at the Eligible Customer's expense. A System Impact Study does not evaluate options associated with facilities expansion or network upgrades.

Assessment of the Need

The Transmission Provider will make an assessment whether a System Impact Study is required to determine if the requested service can be accommodated. In making this assessment, the Transmission Provider will rely on operating experience and available technical information. The Eligible Customer will be advised of the result of this assessment as follows:

- A System Impact Study is not required because the available information is sufficient to make a decision whether to approve or reject the requested service; or

- A System Impact Study is required before making a decision on the requested service.

Guidelines and Principles

In order to perform a System Impact Study the Transmission Provider will develop system models for the known transmission system, including appropriate representation of load and generation for the time frame during which the Transmission Service is requested. These models will include existing agreements and other pending Transmission Service Requests. These models may include the representation of neighboring systems as required.

The study may include load flow, short circuit, stability, loss evaluation, economic and other analyses as appropriate and will be conducted according to the following:

1. The Transmission Provider criteria and guidelines for operation and planning.
2. NPCC criteria and guidelines for design and operation of interconnected power systems.
3. NERC planning and operating standards.
4. Good Utility Practice.

Action Following the Completion

Based on the outcome of the System Impact Study, the Transmission Provider will notify the Eligible Customer of one of the following findings:

1. The requested service can be accommodated without additional operating measures or new facilities.

2. There are system constraints or impairments that may be avoided by system re-dispatch within Prince Edward Island. The Eligible Customer is responsible for any additional cost incurred as a result of implementing such re-dispatch options.

3. The requested service can be accommodated by changing the operating procedures and/or securing Transmission Service outside of Prince Edward Island. The Eligible Customer shall be responsible for contacting the Control Area to determine the general availability of such operating procedures or services.

4. The requested service cannot be accommodated unless new facilities are added and/or upgrades are made to the Transmission System. The Transmission Provider shall tender a Facilities Study Agreement to the Eligible Customer within thirty (30) days of the completion of the System Impact Study. The scope of the Facilities Study will include an estimate of the cost of the new facilities and/or upgrades to the Transmission System, and an estimate of the time required to complete such construction and initiate the requested service. The Eligible Customer has to execute the Facilities Study Agreement within

fifteen (15) days, otherwise the request for service shall be deemed withdrawn.

5. The requested service cannot be accommodated because of equipment limitations or it can cause unacceptable system performance or reliability risks. The Eligible Customer can decide whether to modify or cancel the request.

ATTACHMENT E

Index of Point-To-Point Transmission Service Customers

The index of Point-To-Point Transmission Service Customers, including the date of service, is posted on the Transmission Provider's website.

ATTACHMENT F

Service Agreement for Network Integration Transmission Service

1.0 This Service Agreement, dated as of ____________________, is entered into, by and between Maritime Electric Company, Limited (the Transmission Provider), and ______________________________ (the Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service under the OATT.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 29.2 of the OATT.

4.0 Service under this Service Agreement shall commence on the later of (1) the requested service commencement date or (2) the date on which construction of all Interconnection Equipment, any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) the date on which a Network Operating Agreement is executed and all requirements of said Agreement have been completed (4) the date IRAC approves providing the service, if applicable, or (5) such other date as it is under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Integration Service in accordance with the provisions of Part III of the OATT and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Maritime Electric Company, Limited – OATT Administrator

180 Kent Street

PO Box 1328

Charlottetown, PE C1A 7N2

Phone: 1-800-670-1012

Fax: (902) 629-3665

Email: OATTAdministrator@MaritimeElectric.com

Transmission Customer:

____

____

____

7.0 Term of Transaction:

____

Start Date:

____

Termination Date:

____

8.0 General description of power and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

9.0 A detailed description of power and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

____

____

10.0 Detailed description of each Network Resource, including any operating restrictions:

____

____

____

11.0 Detailed description of the Transmission Customer's anticipated use of the Transmission Provider's interfaces:

____

____

____

12.0 Description of any transmission system owned or controlled by the Transmission Customer:

____

____

____

13.0 Name (s) of any other transmission path transmission providers:

____

____

____

14.0 The Network Integration Service Customer's obligation for the following services will be provided as follows:

			Source
1.	Scheduling, System Control and Dispatch		Transmission Provider
2.	Reactive Supply and Voltage Control		Transmission Provider
3.	Regulation and Frequency Response		
	a.	Automatic Generator Control	_____________
	b.	Load Following	_____________
4.	Energy Imbalance		_____________
5.	Spinning Reserve		_____________
6.	Supplemental Reserve		
	6a.	Contingency Reserve - Supplemental	_____________
	6b.	30 Minute Reserve	_____________

7. Real Power Losses ____________

* The Transmission Customer will propose the source of services 3a, 3b, 4, 5, 6a, 6b, and 7. The Transmission Provider will confirm the acceptability of each source of supply proposed by the Transmission Customer.

15.0 Description of required Direct Assignment Facilities:

____

____

16.0 In addition to the charge for Transmission Service and charges for Ancillary Services as set forth in the OATT, the customer will be subject to the following charges:

16.1 System Impact and/or Facilities Study Charges:

____

____

____

16.2 Direct Assignment Facilities Charges:

____

____

____

16.3 Re-dispatch Charges:

____

____

____

16.4 Network Upgrade Charges:

____

____

____

16.5 Other:

____

____

____

17.0 The OATT is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

Maritime Electric Company, Limited
Vice President, Corporate Planning and Energy Supply
180 Kent Street
PO Box 1328
Charlottetown PE C1A 7N2
Fax: (902) 629-3665
Email: VicePresidentEnergySupply@MaritimeElectric.com

By: ______________________________ ______________________________

Name Date

Transmission Customer:

By: ______________________________ ______________________________

Name Date

ATTACHMENT G

Network Operating Agreement

Applicability

This Operating Agreement applies to Network (and Point-to-Point) Loads that are physically connected to the Transmission Provider's Transmission System.

Network Customers that are not physically connected to the Transmission Provider's Transmission System will be governed by the interconnection agreement between the Transmission Provider and the owner of the transmission system facilities to which the Network Customer is physically connected.

NETWORK OPERATING AGREEMENT

Between

Maritime Electric Company, Limited

and

(Insert Facility Owner Name)

(Date)

TABLE OF CONTENTS

ARTICLE

NETWORK OPERATING AGREEMENT

THIS AGREEMENT MADE THIS __________ day of _____________.

BETWEEN: Maritime Electric Company, Limited (MECL), a duly incorporated Company having its Head Office in the City of Charlottetown, Prince Edward Island, hereinafter called "the Transmission Provider",

- and -

__________________ a duly incorporated Company having its Head Office in the City of _______________________ hereinafter called "the Customer",

Both of which may hereinafter be referred to as "the Parties hereto".

WHEREAS the Customer is the owner and operator of facilities located in _________________, the County of ______________________ in the Province of Prince Edward Island (the "Customer's premises"), and requires a connection to the transmission system in Prince Edward Island;

AND WHEREAS the Transmission Provider has agreed to provide connection service and the Customer has agreed to take connection service from the Transmission Provider for aforesaid Customer premises pursuant to the terms and conditions of this Agreement.

NOW THEREFORE this Agreement witnesses that in consideration of the premises and the mutual covenants and agreements hereinafter set forth, the Parties hereto mutually covenant and agree as follows:

1. DEFINITIONS

In this Agreement, unless the context otherwise requires, the following definitions shall apply:

Transmission Provider Facilities

The Transmission Provider Facilities are the transmission system of the Transmission Provider and the necessary _______ kV extension thereof constructed to the Delivery Point, together with the Metering Equipment, all of which are provided, owned and maintained by the Transmission Provider.

Customer Facilities

The Customer Facilities are the facilities beyond the Delivery Point which are provided, owned and maintained by the Customer and, in addition, shall be deemed to also include any Rental Facilities.

Without limiting the generality of the foregoing, these facilities include

____

____

Delivery Point

The Delivery Point is the place at which the Customer Facilities and the Transmission Provider Facilities are connected together, specifically ____ as shown on the Transmission Provider's Substation Diagram No. __________ dated _______________________________ attached hereto and marked Appendix A.

Good Utility Practice

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by law.

Metering Equipment

The Metering Equipment is the meters and associated equipment approved by Industry Canada or such other authority as may from time to time be charged with such responsibility, required for measuring power and energy supplied to the Customer under this Agreement.

Metering Point

The Metering Point is the point at which all power and energy supplied to the Customer is measured. The Metering Point is at or near the Delivery Point.

Rental Facilities

The Rental Facilities are those facilities provided, owned and maintained by the Transmission Provider for which the Customer pays a Rental Charge.

Without limiting the generality of the foregoing, these facilities include

____

____

2. CHARACTERISTICS OF CONNECTION SERVICE

2.1 Characteristics of Supply

Subject to Article 3.1 hereof the transmission connection service supplied to the Customer at the Delivery Point shall be three phase alternating current at the nominal frequency of 60 hertz and at a nominal voltage of ___________ volts between phases.

2.2 Metering

In this section where reference is made to Industry Canada it shall also be deemed to include any other authority as may from time to time be charged with the responsibility for metering.

The Transmission Provider shall, at its cost, provide, install and maintain the Metering Equipment. If requested by the Transmission Provider, the Customer shall provide at the Customer's expense adequate space and facilities on the Customer's premises satisfactory to the Transmission Provider for the installation and maintenance of the Metering Equipment.

If, at any time, the Metering Equipment is found to be inaccurate by more than the limits specified by Industry Canada or other authorized standard setting body, the Metering Equipment or any faulty components thereof shall be promptly replaced, repaired or readjusted by the Transmission Provider at the Transmission Provider’s expense.

The Transmission Provider may modify or replace the Metering Equipment from time to time.

3. GENERAL OBLIGATIONS OF THE CUSTOMER

3.1 Customer's Equipment

The Customer shall be responsible for installing and maintaining protective equipment to protect the Customer Facilities from variations in frequency and voltage or from temporary delivery of other than three phase power.

The Customer agrees that all motors, transformers and other equipment utilized in its installation shall conform with Canadian Standards Association requirements, and shall be wired, connected and operated so as not to produce detrimental effects on the Transmission Provider Facilities which will adversely affect the adequacy of service to the Customer and other customers.

3.2 Electrical Harmonics

Electrical harmonics shall be considered as components of current or voltage whose frequency is some multiple of the 60 hertz fundamental frequency. The Customer shall assume the responsibility of direct loss by reason of damages to the Transmission Provider Facilities caused by electrical harmonics produced in the Customer Facilities provided that such liability shall be restricted to the repair or, if necessary, the replacement or modification of such Transmission Provider Facilities which have been damaged or made necessary by reason of electrical harmonics produced in the Customer Facilities. The Customer agrees to take all reasonable steps to limit the effects of any electrical harmonics which may be produced in the Customer Facilities to a level tolerable to the Transmission Provider. The Transmission Provider shall cooperate with the Customer in the investigation of any harmonic problems and the analysis of corrective measures. The Transmission Provider reserves the right to discontinue the supply of power and energy where in its opinion the reliability of the Transmission Provider Facilities is threatened by the presence of electrical harmonics.

3.3 Load Balance

The Customer agrees to take and use the three phase current supplied through the Transmission Provider's transmission system in such manner that in no case shall the difference between any two phases be greater than 5%. The Customer, upon written instructions from the Transmission Provider, shall so adjust its load as to comply with this requirement.

3.4 Right-of-Way

The Customer agrees to provide and arrange for the necessary right-of-way on the

Customer's premises for the appropriate Transmission Provider Facilities and Rental Facilities free of cost to the Transmission Provider during the continuance of this Agreement, renewal or renewals thereof, and for six (6) months thereafter, so that the Transmission Provider, its subcontractors, their respective employees and agents may enter upon the same and build, install and erect, construct, operate, repair and remove any or all of the appropriate Transmission Provider Facilities or Rental Facilities, all of which shall not unduly interfere with the Customer's operations and which in the opinion of the Transmission Provider are necessary for the delivery of transmission service under this Agreement. Any changes which the Customer may request the Transmission Provider to make in the location of the Transmission Provider Facilities or Rental Facilities shall be made at the expense of the Customer.

3.5 Right of Access

One or more representatives of the Transmission Provider appointed for this purpose may, at any reasonable time during the continuance of this Agreement, have access to the Customer's premises for the purposes of but not limited to meter reading, inspection, operation, testing, adjustment, repair, alteration, reconstruction, and removal of the Transmission Provider Facilities, or for the purpose of inspecting the Customer Facilities and taking records therefrom as required for compliance with this Agreement.

3.6 Preparation for the Receipt of Transmission Connection Service

The Customer agrees to prepare for the receipt and use of transmission connection services hereunder and to supply, erect and maintain at its own risk, cost and charge, all transformers, switchgear, protective equipment, as well as poles, wires, hardware, cables, fittings, insulators and materials used in distribution on the Customer's premises beyond the Delivery Point.

In addition to the aforegoing the Customer agrees to provide, own and maintain beyond the Delivery Point any equipment which the Transmission Provider deems necessary from time to time during the continuance of this Agreement for the safety and security of operation of the Transmission Provider Facilities in accordance with Good Utility Practice. All the said equipment of the Customer shall be subject to the approval of the Transmission Provider and shall be installed, maintained and operated in a manner satisfactory to the Transmission Provider.

3.7 Customer's Responsibility for the Transmission Provider Facilities on its Premises

All Transmission Provider Facilities and Rental Facilities furnished and installed on the Customer's premises shall remain the property of the Transmission Provider and should such Transmission Provider Facilities or Rental Facilities be destroyed or damaged from any cause due to the Customer, or from any peril originating on the Customer's premises, the Customer shall reimburse the Transmission Provider for the full cost of repair or replacement.

3.8 Insulation Contamination

Contaminants shall be considered as foreign matter or substance deposited on insulation components which reduce the value and effectiveness of the insulation and may consist of dust, particles or chemicals either dry or in solution.

The Customer shall be responsible for the correction of contamination problems occurring on the Customer Facilities. If contaminants caused by activities on the Customer's premises accumulate on the Transmission Provider Facilities which, in the opinion of the Transmission Provider affect the insulating characteristics, the Customer shall bear the cost of removal of contamination or replacement of insulation components as deemed necessary by the Transmission Provider. Interruptions of service occasioned to correct contamination problems shall be, where possible, arranged at a time mutually agreeable to the Customer and the Transmission Provider. Notwithstanding the above the Transmission Provider reserves the right to discontinue the supply of power and energy at its discretion where the reliability of its system is threatened by the presence of contaminants on insulation components.

4. GENERAL RIGHTS AND OBLIGATIONS OF TRANSMISSION PROVIDER

4.1 Interruption of Supply

The Transmission Provider shall provide a regular and uninterrupted delivery of transmission connection services under the terms of this Agreement but shall have no liability to the Customer for loss or damage from any failure of delivery in respect of any abnormality, delay, interruption or other partial or complete failure in the said delivery when such loss or damages are caused by something that is beyond the ability of the Transmission Provider to control by reasonable and practicable effort, said effort to be measured by Good Utility Practice as defined herein.

The Transmission Provider shall have the right to suspend the delivery of transmission connection services for the purpose of safeguarding life or property, for making repairs, changes, renewals, improvements or replacements to the Transmission Provider Facilities or Rental Facilities but all such interruptions shall be of a minimum duration consistent with the exigencies of the case, and when possible, arranged for a time least objectionable to the Customer, and such interruptions shall not release the Customer from its obligation to pay all charges pursuant to this Agreement during the period of any such suspensions and to resume the use of transmission connection services when the service is restored. When such repairs, changes, renewals, improvements or replacements are of a non-emergency routine nature that can be scheduled in advance by the Transmission Provider, the Transmission Provider or its designate shall advise the Customer in writing at least two (2) weeks in advance of such work. The Customer shall be responsible for any additional costs incurred by the Transmission Provider resulting from performing, at the Customer's request, such repairs, changes, renewals, improvements or replacements outside of normal working hours.

4.2 Special or Consequential Damages

Notwithstanding any other provision in this contract, the Transmission Provider shall not be liable to the Customer for special or consequential damages, or damages for loss of use, arising directly or indirectly from any breach of this contract, fundamental or otherwise, and in particular but not limited to interruption of supply or from any acts or omissions of its employees.

4.3 Removal of Equipment at Termination

The Transmission Provider shall, at the termination of this Agreement, or within six (6) months thereafter, remove from the Customer's premises the appropriate Transmission Provider Facilities and Rental Facilities which may have been installed by the Transmission Provider for the supply of transmission connection service under this Agreement, but after the expiration of said six (6) months period all such Transmission Provider Facilities and Rental Facilities shall be at the risk of the Transmission Provider.

5. ENVIRONMENTAL CONTAMINATION

5.1 Environmental Contamination

The Customer shall comply with all environmental laws and regulations with respect to Customer Facilities.

The Customer shall indemnify and save harmless the Transmission Provider from all loss, expense, damage or injury to persons or property inclusive of the Transmission Provider’s property arising as a result of environmental damage, contamination and/or injury due to or caused by the Customer.

The Transmission Provider shall comply with all environmental laws and regulations with respect to the Transmission Provider Facilities.

The Transmission Provider shall indemnify and save harmless the Customer from all loss, expense, damage or injury to persons or property inclusive of Customer property arising as a result of environmental damage, contamination and/or injury due to or caused by the Transmission Provider.

Both parties agree to immediately notify the other of any environmental incident that occurs relative to the terms of this Agreement.

6. FORCE MAJEURE

6.1 Force Majeure

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party’s control. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Agreement.

If a Party relies on the occurrence of an event or condition described above, as a basis for being excused from performance of its obligations under this Agreement, then the Party relying on the event or condition will: (i) provide prompt written notice of such Force Majeure event to the other Party giving an estimation of its expected duration and the probable impact on the performance of its obligations hereunder; (ii) exercise all reasonable efforts to continue to perform its obligations under this Agreement; (iii) expeditiously take commercially reasonable action to correct or cure the event or condition excusing performance; provided that settlement of strikes or other labor disputes will be completely within the sole discretion of the Party affected by such strike or labor dispute; (iv) exercise all reasonable efforts to mitigate or limit damages to the other Party; and (v) provide prompt notice to the other Party of the cessation of the event or condition giving rise to its excuse from performance. All performance obligations hereunder, other than any payment obligation, or any and all obligations which were incurred prior to the Force Majeure event, will be extended by a period equal to the term of the resultant delay.

7. INDEMNITY

7.1 Indemnification Obligation

Subject to the limitations on and exclusions of liability set forth herein, each Party agrees to indemnify, hold harmless, and defend the other Party, its Affiliates, and their respective officers, directors, employees, agents, contractors, subcontractors, invitees and successors (collectively the Indemnitees), from and against any and all claims, liabilities, costs, damages, and expenses which may be imposed on or asserted at any time against an Indemnitee by any third party (including, without limitation, reasonable attorney and expert fees, and disbursements incurred by any Indemnitee in any action or proceeding) for or arising from damage to property, injury to or death of any person, including the other Party's employees or any third parties (collectively, the Loss), to the extent caused wholly or in part by any act or omission, negligent or otherwise, by the indemnifying Party and/or its officers, directors, employees, agents, and subcontractors arising out of or connected with the indemnifying Party's performance or breach of this Agreement, or the exercise by the indemnifying Party of its rights hereunder; provided, however, that no indemnification by a Party is required under this Section to the extent such Loss is caused by or results from the negligence or willful misconduct of the other Party or its Indemnitee(s). In the event that such Loss is the result of the negligence of both Parties, each Party shall be liable to the other to the extent or degree of its respective negligence, as determined by mutual agreement of both Parties, or in the absence thereof, as determined by the adjudication of comparative negligence.

7.2 Control of Indemnification

If any third party shall notify any Indemnitee of a claim with respect to any matter which may give rise to a claim for indemnification against the other Party (the Indemnifying Party) under this Section, then the Indemnitee shall notify the Indemnifying Party thereof promptly (and in any event within ten (10) Business Days after receiving any written notice from a third party). The Indemnifying Party's liability hereunder to the

Indemnitee shall be reduced to the extent the Indemnifying Party is materially adversely prejudiced by the Indemnitee's failure to provide timely notice hereunder. In the event any Indemnifying Party notifies the Indemnitee within ten (10) Business Days after the Indemnitee has given notice of the matter that the Indemnifying Party is assuming the defense thereof, (i) the Indemnifying Party will defend the Indemnitee against the matter with counsel of its choice reasonably satisfactory to the Indemnitee, (ii) the Indemnitee may retain separate co-counsel at its sole cost and expense (except that the Indemnifying Party will be responsible for the fees and expenses of the separate counsel to the extent the Indemnitee reasonably concludes that the counsel the Indemnifying Party has selected has a conflict of interest), (iii) the Indemnitee will not consent to the entry of any judgment or enter into any settlement with respect to the matter without the written consent of the Indemnifying Party (which shall not be unreasonably withheld, and (iv) the Indemnifying Party will not consent to the entry of any judgment with respect to the matter, or enter into any settlement which does not include a provision whereby the plaintiff or claimant in the matter releases the Indemnitee from all liability with respect thereto, without the written consent of the Indemnitee (which shall not be unreasonably withheld). In the event the Indemnifying Party does not notify the Indemnitee within ten (10) Business Days after the Indemnitee has given notice of the matter that the Indemnifying Party is assuming the defense thereof, however, the Indemnitee may defend against the matter in any manner it may deem appropriate.

7.3 Recovery of Enforcement Costs

Notwithstanding any other provision of this Agreement, the indemnifying Party will pay all damages, settlements, expenses and costs, including Costs of investigation, court costs and reasonable attorneys' fees and costs the other Party incurs in enforcing this Section 10.0. Each Party agrees its indemnification obligation, as detailed under this Section 10.0, will survive expiration or termination of the Agreement.

8. TERM OF AGREEMENT AND GOOD FAITH NEGOTIATION

8.1 Term of Agreement

The Initial Term of this Agreement shall commence on the day and year first above written and continue in force for a period of five (5) years. This Agreement shall terminate on the expiration of the Initial Term provided one of the Parties hereto has given at least twelve (12) months written notice to the other Party. Should neither of the Parties hereto give notice to terminate this Agreement at the expiration of the Initial Term, this Agreement shall continue in full force and effect provided however that it may be terminated at any time after the expiration of the Initial Term by either Party having first given at least twelve (12) months written notice of termination to the other Party.

8.2 Good Faith Negotiations Upon Occurrence of Certain Events

If the Province, IRAC or Maritime Electric implements a change in any law, regulation, rule or practice; which change affects or is reasonably expected to affect the provision of Network Integration Transmission Service to Customer pursuant to this Agreement, the Parties agree to negotiate in good faith to determine the amendments, if any, to this Agreement reasonably necessary to conform the terms of Network Integration Transmission Service to such change, and where practicable will provide Customer with thirty (30) days advance notice; provided that if the Parties are unable to each agreement as to what, if any, amendments are necessary, Customer will have the right to oppose such filing and participate fully in any proceeding established by IRAC to address such amendment.

9. FORMER AGREEMENTS

9.1 Former Agreements

This Agreement and all attached schedules constitute the entire agreement between the parties to this Agreement pertaining to the subject matter hereof and supercedes all prior and contemporaneous agreements, understandings, negotiations and discussions whether oral or written, of the parties and there are not warranties, representations or other agreements between the parties in connection with the subject matter of this Agreement except as specifically set forth herein.

10. SUCCESSORS OF PARTIES

10.1 Successors and Assigns

This Agreement shall extend to and be binding upon and inure to the benefit of the Parties hereto and their respective successors and permitted assigns. Neither Party shall assign its rights and obligations hereunder without the prior written consent of the other Party, such consent not to be unreasonably withheld, conditioned or delayed; however, either Party may, without the consent of the other Party (and without relieving itself from its obligations hereunder),

a. assign this Agreement or the accounts, revenues or proceeds hereof as security for its corporate debt or financing the Project,

b. assign this Agreement to an affiliate ("affiliate" having the meaning given in the Canada Business Corporations Act), or

c. assign this Agreement to any person or entity succeeding to all or substantially all of the assets of the assigning Party;

provided, however, that in each such case, any such assignee or the purchaser of this agreement from an assignee referred to in (a) shall agree in writing to be bound by the terms and conditions hereof prior to exercising any of its rights as assignee and further provided that in the case of an assignment by the Customer, the assignee is owner of the Project.

11. MODE OF DELIVERY

11.1 Mode of Delivery

Except as provided by this Agreement or otherwise agreed from time to time, any notice or other communication which is required by this Agreement to be given in writing, shall be sufficiently given if delivered personally to a senior official of the Party for whom it is intended or faxed or e-mailed or sent by registered mail, addressed as follows:

a. In the case of the Company, to:

Attention:

b. In the case of the Transmission Provider, to:

Vice President, Corporate Planning and Energy Supply
180 Kent Street
PO Box 1328
Charlottetown PE C1A 7N2
Fax: (902) 629-3665
E-mail: VicePresidentEnergySupply@MaritimeElectric.com

or delivered to such other person or faxed or e-mailed or sent by registered mail to such other address as either Party may designate for itself by notice given in accordance with this Section.

Any notice or other communication so mailed shall be deemed to have been received on the fifth business day following the day of mailing or if faxed or e-mailed shall be deemed to have been received on the same business day as the date of the fax or e-mail or if delivered personally shall be deemed to have been received on the date of delivery.

12. ADMENDMENT

12.1 Amendment

If at any time during the continuance of this Agreement the parties shall deem it necessary or expedient to make any alteration or addition to this Agreement it shall be done by way of a written agreement which shall be supplemental and form part of this Agreement.

13. SEVERANCE AND GOVERNING LAW

13.1 Severance

It is intended that all provisions of this Agreement shall be fully binding and effective between the parties, but in the event that any particular provision or provisions or a part of one is found void, voidable or unenforceable for any reason whatsoever, then the particular provision or provisions or part of the provision shall be deemed severed from the remainder of this Agreement and all other provisions shall remain in full force.

13.2 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of Prince Edward Island and/or any applicable Federal laws.

14. DISPUTES

14.1 Dispute Resolution

Neither MECL nor the Customer shall commence any proceedings against the other party with respect to the interpretation or enforcement of this Agreement unless and until it has first referred the matter in issue for determination to two senior executives, one from each party. If these senior executives, despite their best efforts, are unable to determine the matter within thirty (30) days of its referral to them, then the parties may refer the matter in issue to binding arbitration.

14.2 Arbitration

Any matter in issue between the Parties as to their rights under this Agreement may, by mutual agreement of the parties hereto, be submitted to arbitration. Any dispute to be decided by arbitration shall be decided by a panel of three arbitrators, each party to choose one arbitrator within ten (10) days of the referral of the dispute to arbitration and the two so chosen shall, within a further ten (10) days, select a third arbitrator to be chairman in accordance with the *Arbitration Act of Prince Edward Island* or any re-enactment of the same. The arbitrators shall be knowledgeable in the electric industry and shall not have any current or past business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrators shall provide each of the parties an opportunity to be heard and shall generally conduct the arbitration in accordance with the provisions of the *Arbitration Act of Prince Edward Island.* Unless otherwise agreed by the parties, the arbitrators shall render a decision within ninety (90) days of appointment and shall notify the parties in writing of such decision and the reasons therefore. The arbitrators shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change the Agreement in any manner. The decision of the arbitrators shall be conclusive, final and binding upon the parties. The decision of the arbitrators may be appealed solely on the grounds that the conduct of the arbitrators, or the decision itself, violated the provisions of the *Arbitration Act of Prince Edward Island*. The *Arbitration Act of Prince Edward Island* shall govern the procedures to apply in the enforcement of any award made. If it is necessary to enforce such award, all costs of enforcement shall be payable and paid by the party against whom such award is enforced. Each Party shall be otherwise responsible for its own costs incurred during the arbitration process.

14.3 Referral of Dispute to IRAC

Notwithstanding anything contained in this Section 14, either party may:

a. instead of proceeding through the Arbitration procedures outlined in Section 14.2 above, elect to refer a dispute directly to IRAC by filing a complaint with IRAC in the manner set out below and the decision of IRAC with respect to the matter shall be final and binding and the matter in dispute cannot thereafter proceed to the dispute resolution process;

b. if either party is dissatisfied with the results of an arbitration decision rendered pursuant to Section 14.2, refer a complaint to IRAC for determination and the decision of IRAC with respect to the matter shall be final and binding.

No complaint may be referred to IRAC pursuant to Section 14.3 (A) or (B) until the Dispute Resolution procedures set out in Section 14.1 have been concluded.

Complaints filed with IRAC must be in writing and must include reasons and evidence in support of the party's position. A copy of the complaint, together with the supporting reasons and evidence, must be filed with the other party. IRAC may require a complainant to provide such security for the costs incurred or to be incurred by IRAC, as it considers reasonable, and such security may be forfeited to IRAC if the complaint is not substantiated.

15. REPRESENTATIONS OF MECL

MECL represents and warrants to Customer as follows:

15.1 Organization

MECL is a corporation having its head office in Charlottetown, Prince Edward Island validly existing and in good standing under the laws of the Province of Prince Edward Island and MECL has the requisite power and authority to carry on its business as now being conducted;

15.2 Authority Relative to this Agreement

MECL has the requisite power and authority to execute and deliver this Agreement and to carry out the actions required of it by this Agreement. The execution and delivery of this Agreement and the actions it contemplates have been duly and validly authorized by Board of Directors of MECL, and no other corporate proceedings on the part of MECL are necessary to authorize this Agreement or to consummate the transactions contemplated hereby. The Agreement has been duly and validly executed and delivered by MECL and constitutes a legal, valid and binding Agreement of MECL enforceable against it in accordance with its terms;

15.3 Regulatory Approval

MECL has obtained or will obtain all approvals of, and has given or will give all notices to, any public authority that are required for MECL to execute, deliver and perform its obligations under this Agreement;

15.4 Compliance With Law and Agreements

MECL represents and warrants that: (i) it is not in violation of any applicable law, statute, order, rule, or regulation promulgated or judgment entered by any federal, provincial or local governmental authority, which individually or in the aggregate would adversely affect MECL's entering into or performance of its obligations under this Agreement; and (ii) its entering into and performance of its obligations under this Agreement will not give rise to any default under any agreement to which it is a party; and

MECL represents and warrants that it will comply with all applicable laws, rules, regulations, codes, and standards of all applicable federal, provincial, and local governmental agencies having jurisdiction over MECL or the transactions under this Agreement and with which failure to comply could reasonably be expected to have a material adverse effect on Customer.

16. REPRESENTATIONS OF CUSTOMER

Customer represents and warrants to MECL as follows:

16.1 Organization

Customer is a (INSERT TYPE OF COMPANY) organized, validly existing and in good standing under the laws of the Province of Prince Edward Island, Canada, and Customer has the requisite power and authority to carry on its business as now being conducted;

16.2 Authority Relative to this Agreement

Customer has the requisite power and authority to execute and deliver this Agreement and to carry out the actions required of it by this Agreement. The execution and delivery of this Agreement and the actions it contemplates have been duly authorized by proceedings on the part of Customer are necessary to authorize this Agreement or to consummate the transactions contemplated hereby. This Agreement has been duly and validly executed and delivered by Customer and constitutes a legal, valid and binding Agreement of Customer enforceable against it in accordance with its terms;

16.3 Regulatory Approval

Customer has obtained all approvals of, and given all notices to, any public authority that are required for Customer to execute, deliver and perform its obligations under this Agreement;

16.4 Compliance with Law and Agreements

Customer represents and warrants that: (i) it is not in violation of any applicable law, statute, order, rule, or regulation promulgated or judgment entered by any federal, provincial, state, or local governmental authority, which, individually or in the aggregate, would adversely affect Customer’s entering into or performance of its obligations under this Agreement; and (ii) its entering into and performance of its obligations under this Agreement will not give rise to any default under any agreement to which it is a party; and

Customer represents and warrants that it will comply with all applicable laws, rules, regulations, codes, and standards of all federal, state, provincial, and local governmental agencies having jurisdiction over Customer or the transactions under this Agreement and with which failure to comply could reasonably be expected to have a material adverse effect on MECL.

17. REPRESENTATIONS OF BOTH PARTIES

The representations in Sections 14.5 and 15.5 will continue in full force and effect for the term of this Agreement.

IN WITNESS WHEREOF the Parties hereto have caused their corporate seals to be hereto affixed and these presents to be executed by their duly authorized officers respectively.

TRANSMISSION PROVIDER	CUSTOMER
______________________________	______________________________
______________________________	______________________________

Appendix A

Substation Diagram

ATTACHMENT H

Annual Transmission Revenue Requirement
For Network Integration Transmission Service

1. The rate charges for Network Integration Service will be C$2,543.58 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.

ATTACHMENT J

(To Be Filed Separately with IRAC)

GENERATION INTERCONNECTION AGREEMENT

BY AND BETWEEN

MARITIME ELECTRIC COMPANY, LIMITED

AND

(INSERT COMPANY NAME)

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LIST OF SCHEDULES

GENERATOR INTERCONNECTION AGREEMENT

This Generation Interconnection Agreement dated as of (INSERT DATE) by and between Maritime Electric Company, Limited (MECL), a corporation having its head office in Charlottetown, Prince Edward Island and (INSERT COMPANY NAME) (Customer), a (INSERT TYPE OF CORPORATION), with offices at (INSERT OFFICE ADDRESS).

WHEREAS, Customer is developing a (INSERT TYPE OF UNIT) generation facility (Facility) to be located at (INSERT LOCATION OF GENERATOR);

WHEREAS, Customer desires to interconnect the Facility with the (INSERT VOLTAGE) Transmission System owned by MECL connecting the (NAME FACILITIES);

WHEREAS, Customer requires certain Interconnection Service from MECL for its Generation, as provided in this Agreement;

WHEREAS, additions, modifications, and upgrades must be made to certain existing transmission facilities owned by MECL in order to accommodate the interconnection; and

WHEREAS, the Parties have agreed to execute this mutually acceptable Generation Interconnection Agreement in order to provide certain Interconnection Service to Customer; to provide for the additions, modifications, and upgrades to MECL's Transmission System; and to define the continuing responsibilities and obligations of the Parties; in accordance with the terms and conditions set forth herein.

NOW THEREFORE, in order to carry out the transactions contemplated in this Agreement, and in consideration of the mutual representations, covenants and agreements hereinafter set forth, the Parties hereto, intending to be legally bound hereby, agree as follows:

SECTION 1.0 – DEFINITIONS

Wherever used in this Agreement with initial capitalization, the following terms will have the meanings specified or referred to in this Section 1. Terms used in this Agreement that are not defined herein will have the meanings customarily attributed to such terms by the electric utility industry in Canada. The words “shall” and “will” are used interchangeably throughout the Agreement, the use of either connotes a mandatory requirement, and the use of one or the other shall not mean a different degree of right or obligation for either Party. All references to Sections and Schedules herein refer to those attached to this Agreement unless otherwise stated.

1.1 "Affiliate" means, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 "Agreement" means this Generation Interconnection Agreement between MECL and Customer, including all Schedules attached hereto, as the same may be amended, supplemented, or modified in accordance with its terms.

1.3 “Business Day” is Monday to Friday, inclusive, excluding statutory holidays for MECL. The regular business hours on a Business Day are 08:00 hours to 16:00 hours Atlantic Time.

1.4 “Customer” means (INSERT CUSTOMER NAME), and includes its permitted successors and assigns.

1.5 “Customer-Owned Interconnection Facilities” means those facilities or portions of facilities owned by Customer and identified as Customer-Owned Interconnection Facilities in Schedule A.

1.6 “Direct Assignment Facilities,” also referred to as MECL-Owned Interconnection Facilities, means the facilities or portion of facilities that are constructed for the sole use/benefit of Customer, and installed and owned by MECL under this Agreement. Such facilities are identified as Direct Assignment Facilities in Schedule A, as it may be amended, which is attached hereto and incorporated herein by reference. The costs of such Direct Assignment Facilities are identified in Schedule D (with respect to Revenue Meters) and Schedule I (with respect to all other Direct Assignment Facilities).

1.7 “Effective Date” shall have the meaning set forth in Section 2.1.

1.8 “Emergency” means any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

1.9 "Environmental Laws" means all federal, provincial, and local laws (including common laws), regulations, rules, ordinances, codes, decrees, judgments, binding directives, or judicial or administrative orders relating to protection, preservation or restoration of human health, the environment, or natural resources, including, without limitation, laws relating to Release(s) or threatened Release(s) of Hazardous Substances into any media (including, without limitation, ambient air, surface water, groundwater, land, surface and subsurface strata) or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, release, transport or handling of Hazardous Substances.

1.10 “Event of Default” has the meaning set forth in Section 8.1.

1.11 “Facilities Study” means the studies conducted pursuant to the Facilities Study Agreement dated (INSERT DATE), between MECL and Customer, as it may be amended from time to time in accordance with its terms.

1.12 “Facility” means all of Customer’s generation plant and equipment with the net capacity as designated in Schedule A, including Customer-Owned Interconnection Facilities, identified in Schedule A, located at (INSERT LOCATION OF GENERATOR).

1.13 "Facility Station Service" means all electric service requirements used in connection with the operation and maintenance of the entire Facility, including, without limitation, stand-by, supplemental, maintenance, and interruptible power, and delivery of such service.

1.14 “Generation” means the electrical capacity, energy, and/or ancillary services produced at the Facility.

1.15 "Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.16 "Hazardous Substances" means (a) any petro-chemical or petroleum products, oil or coal ash, radioactive materials, radon gas, asbestos in any form that is or could become friable, urea formaldehyde foam insulation and transformers or other equipment that contain dielectric fluid which may contain levels of polychlorinated biphenyls; (b) any chemicals, materials, or substances defined as or included in the definition of "hazardous substances,” "hazardous wastes,” "hazardous materials," "restricted hazardous materials,” "extremely hazardous substances,” "toxic substances,” "contaminants,” or "pollutants" or words of similar meaning and regulatory effect; or (c) any other chemical, material, or substance, exposure to which is prohibited, limited or regulated by applicable Environmental Laws.

1.17 "Index Rate" means the RBC Royal Bank Prime Rate, in effect on the date such interest begins to accrue. The "RBC Royal Bank Prime Rate" is defined as the prime rate per annum as charged by the RBC Royal Bank, Queen Street Branch in Charlottetown, on the last banking day of the month for which payment is due.

1.18 "Interconnection Facilities" means the Customer-Owned Interconnection Facilities and the MECL-Owned Interconnection Facilities collectively.

1.19 "Interconnection Facilities Support Charge - Capital Related" (IFSC-CR) means a charge determined or modified by MECL, to the extent applicable, to recover all capital costs related to the facilities installed or modified after the Effective Date, required for providing Interconnection Service. The IFSC-CR shall be defined in Schedule I of this Agreement, as such Schedule I may be amended or superseded from time to time. The current IFSC-CR is stated in Schedule I of this Agreement.

1.20 "Interconnection Facilities Support Charge - Non-Capital Related" (IFSC-NCR) means a charge, as accepted or approved by IRAC, to the extent applicable, and which may be modified by MECL, as accepted or approved by IRAC, to the extent applicable, designed to enable MECL to recover all on-going non-capital support costs related to the facilities required for providing Interconnection Service. The current IFSC-NCR is provided in Schedule 9 of MECL's Open Access Transmission Tariff.

1.21 "Interconnection Request" shall mean Customer's request to interconnect a new facility, or to increase the capacity of, or make a material modification to the operating characteristics of, an existing Facility that is interconnected with the MECL's Transmission System. The "Interconnection Request" procedure is provided in Schedule J.

1.22 "Interconnection Service" means all of the services and facilities provided for in this Agreement, including, without limitation, integrating the output of the Facility into

MECL's Transmission System in accordance with the terms, conditions and limitations, if any, resulting from the System Impact Study and Facility Study conducted by MECL on behalf of Customer, as well as to enable the Facility to receive any Facility Station Service, but does not include Transmission Service. Interconnection Service will not include interconnection of any other generating unit owned by Customer, wherever located, to the Transmission System.

1.23 "IRAC" means the Island Regulatory and Appeals Commission.

1.24 "List of Qualified Persons" means the list of Customer personnel approved by MECL who meet the requirements to switch, tag, and ground electrical equipment set forth in MECL's Standard Protection Code Manual or its successor.

1.25 "Maintain" means construct, reconstruct, install, inspect, test, repair, replace, operate, patrol, maintain, use, modernize, upgrade, or other similar activities.

1.26 "Measurement Canada" means the Government of Canada agency established to administer and enforce the Electricity and Gas Inspection Act.

1.27 "MECL" means Maritime Electric Company, Limited, and includes its permitted successors and assigns.

1.28 "MECL's Open Access Transmission Tariff" or "MECL's OATT" or "MECL's Tariff" or "Tariff" means the Open Access Transmission Tariff filed by MECL and approved by IRAC, as such Tariff may be amended from time to time.

1.29 "MECL-Owned Interconnection Facilities," also referred to as Direct Assignment Facilities, means facilities or portions of facilities used by Customer, or jointly used by Customer and MECL, that are owned by MECL. The Direct Assignment Facilities are identified in Schedule A.

1.30 "Metering Point(s)" is the location of any and all meter(s), as approved by MECL, used to determine the amount of Generation delivered to the Transmission System.

1.31 "NERC" means North American Electric Reliability Council or its successor.

1.32 “NPCC” means Northeast Power Coordinating Council or its successor. NPCC is a Regional reliability council of NERC.

1.33 “Other Direct Assignment Facilities” means the Transmission Upgrades used by MECL or others (network facilities) which would not be necessary except to interconnect and/or accommodate the output of the Customer’s Facility and that are identified as Other Direct Assignment Facilities in Schedule A. The Customer’s cost responsibility for Other Direct Assignment Facilities will be determined in accordance with Attachment K of the MECL OATT and set forth in Schedule I of this Agreement.

1.34 “Parties” means MECL and Customer collectively; individually a “Party”.

1.35 "Point of Interconnection" means the point where Customer’s Facility connects to MECL's Transmission System, as specified in Schedule A to this Agreement.

1.36 "Point of Receipt" means the point on MECL's Transmission System where capacity and energy generated by Customer will be received, as specified in Schedule A.

1.37 "Primary" means power equipment such as transformers, circuit breakers, rigid or strain bus and other equipment operating above 600 volts.

1.38 “Project Finance Holder” means (a) any holder, trustee or agent for holders, of any Project Financing, or (b) any purchaser from the Facility to which Customer has granted a mortgage or other lien or interest as security for some or all of Customer’s obligations under the corresponding power purchase agreement.

1.39 “Project Financing” means (a) one or more loans and/or debt issues, together with all modifications, renewals, supplements, substitutions or replacements thereof, the proceeds of which are used to finance or refinance the costs of the Facility, any alteration, modification, expansion or improvement to the Facility, the purchase and sale of the Facility, or the operations of or at the Facility; (b) a power purchase agreement pursuant to which Customer’s obligations are secured by a mortgage, lien or other interest in the Facility; or (c) loans and/or debt issues secured by mortgage, lien or other interest in the Facility.

1.40 “Province” means the Province of Prince Edward Island.

1.41 “Queue Position” shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by MECL.

1.42 “RTU” means remote terminal unit.

1.43 “Release” means release, spill, leak, discharge, dispose of, pump, pour, emit, empty, inject, leach, dump, or allow to escape into or through the environment.

1.44 "Revenue Meters" means all kWh, kVArh, kVAh and demand meters, pulse isolation relays, pulse conversion relays, and associated metering equipment to measure the transfer of energy between the Parties.

1.45 "Secondary Systems" means control or power circuits that operate at or below 600 volts, ac or dc, including but not limited to any hardware, control or protective devices, cables, conductor, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers where signals or energy may be used by Customer, MECL, or their Affiliates.

1.46 “Site Control” shall mean documentation reasonably demonstrating:

1. ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Facility;
2. an option to purchase or acquire a leasehold site for such purpose; or
3. an exclusivity or other business relationship between Customer and the entity having the right to sell, lease or grant Customer the right to possess or occupy a site for such purpose.

1.47 "Switching, Tagging, and Grounding Rules" has the meaning set forth in MECL's Standard Protection Code Manual as amended from time to time, which are hereby incorporated by reference as if fully set forth herein.

1.48 “System Operator” is the entity within MECL that is responsible for the planning, security and reliable operation of the Transmission System including switching and tagging, system monitoring, voltage and VAr control, notifications, transmission services and system restoration.

1.49 “Terminal” means a transmission voltage level substation, switching station or generating station.

1.50 “Transmission Provider” means MECL in its role as the provider of Transmission Service to Customers.

1.51 "Transmission Service" means the services provided to Customer by MECL on the Transmission System.

1.52 "Transmission System" means all of MECL’s transmission equipment and facilities owned, controlled or operated by MECL.

1.53 “Transmission Upgrades” or “Transmission System Upgrades” means the transmission facilities designed, constructed, procured, and installed by MECL under this Agreement. The cost responsibility for such Transmission System Upgrades is set forth in Schedule I.

1.54 "Uplift Charges" means the congestion cost responsibilities (including, without limitation, replacement generation costs and redispatch costs), as determined and billed by the System Operator resulting from (a) temporary operating restrictions being imposed or facilities being temporarily removed from service to accommodate upgrades required to interconnect Customer, or (b) an MECL facility taken out of service for any reason to accommodate Customer during its construction or installation, or during construction or installation MECL is performing on Customer's behalf.

SECTION 2.0 - TERM

2.1 Term

Subject to required regulatory authorizations, this Agreement will become effective when signed by the Parties (Effective Date). This Agreement will remain in effect until (INSERT DATE) (the Term) unless (a) terminated on an earlier date by mutual agreement of the Parties, (b) terminated by Customer upon ninety (90) days' prior written notice to MECL, or (c) otherwise terminated in accordance with the terms of this Agreement. MECL will submit this Agreement to IRAC.

2.2 Good Faith Negotiations Upon Occurrence of Certain Events

If the Province, IRAC, or MECL implements a change in any law, regulation, rule or practice; which change affects or is reasonably expected to affect the provision of Interconnection Service to Customer pursuant to this Agreement, the Parties agree to negotiate in good faith to determine the amendments, if any, to this Agreement reasonably necessary to conform the terms of Interconnection Service to such change, and where practicable will provide Customer with thirty (30) days advance notice; provided that if the Parties are unable to reach agreement as to what, if any, amendments are necessary, Customer will have the right to oppose such filing and participate fully in any proceeding established by IRAC to address such amendment.

2.3 Survival of Certain Provisions

The applicable provisions of this Agreement will continue in effect after expiration or termination hereof to the extent necessary to provide for final billings, billing adjustments and the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect. These provisions include, without limitation, Section 3.2 ("Licence and Access Rights"), Section 10 ("Indemnification"), Section 11 ("Insurance"), and Section 19 ("Limitation of Liability"). Upon termination of this Agreement prior to the expiration of the Term, Customer shall pay any removal and abandonment costs MECL may incur, and any associated costs, or shall continue to pay the charges set forth in Schedule I and Schedule D until the expiration of the Term.

2.4 Effect of Termination

Expiration or termination of this Agreement shall not relieve MECL or Customer of any of its liabilities and obligations arising hereunder prior to the date expiration or termination becomes effective.

2.5 Construction and Installation of MECL-Owned Interconnection Facilities and Other Direct Assignment Facilities

2.5.1 At Customer's expense in accordance with Section 5, MECL shall design, procure, and construct the MECL-Owned Interconnection Facilities and the Other Direct Assignment Facilities, in conformance with Good Utility Practice and in accordance with the information provided in Schedules A to J.

2.5.2 <u>Expedited Design, Procurement, and Construction</u>. Customer may request MECL to design, procure, and construct the MECL-Owned Interconnection Facilities and the Other Direct Assignment Facilities as expeditiously as reasonably possible and to the extent MECL can accommodate Customer's request without jeopardizing the reliability of the MECL System or service to other MECL customers, or causing other inconveniences or disruptions to the conduct of MECL's business, MECL agrees to cooperate and work with Customer to accomplish that objective. If conditions permit, and subject to Customer's obligations herein, MECL will undertake expedited design, procurement, and construction activity prior to completion of the Facilities Study provided Customer pays the estimated cost of such work to MECL prior to MECL undertaking any such activities.

2.5.3 The Parties understand and recognize that performing any activities relating to the design, procurement, and construction of MECL-Owned Interconnection Facilities and the Other Direct Assignment Facilities in an expeditious manner prior to the completion of the Facilities Study may result in additional costs and the procurement of equipment and/or the construction (in whole or part) of additions, modifications, or upgrades that the Facilities Study, when completed, indicates are not necessary to accommodate the interconnection of the Facility. Customer agrees to defend, indemnify, and hold MECL harmless from such risks, and to bear all costs resulting from or associated with the expedition, including those costs associated with and resulting from expediting the design, procurement, and the designing, procuring, or constructing replacement or substitute facilities, so long as such costs are not the result of MECL's, or its Affiliates', gross negligence or reckless or willful misconduct, provided, however, that nothing herein shall limit Customer's rights with respect to third parties.

2.5.4 <u>Disclaimer of Warranties.</u> Customer understands and agrees that the expedited design, procurement or construction activities relating to the MECL-Owned Interconnection Facilities and the Other Direct Assignment Facilities performed prior to the completion of the Facilities Study are being performed for the convenience of Customer. Customer further understands and agrees that regulatory rules and procedures as well as unanticipated and unforeseen changes may adversely impact the usefulness of any such design, procurement or construction activity. Accordingly, MECL makes no representations or warranties, either express or implied, regarding the need for or usefulness, as indicated by the completed Facilities Study, of any design, procurement or construction activity performed prior to the completion of the Facilities Study. MECL specifically disclaims any and all implied warranties, including without limitation any implied warranties of merchantability or fitness for a particular purpose, regarding any such design, procurement or construction activity performed prior to the completion of the Facilities Study, provided, however, that such disclaimer of express warranties, if any, or implied warranties is inapplicable to any design, procurement or construction activity that was undertaken by MECL and was subsequently identified in the Facilities Study as being necessary to accommodate the Facility's interconnection.

2.5.5 Right to Suspend or Terminate Work. Customer reserves the right, upon prior written notice to MECL, to suspend or terminate at any time all work by MECL associated with the design, procurement, or construction of the MECL-Owned Interconnection Facilities or the Other Direct Assignment Facilities, provided, however, that, if necessary, an equitable adjustment will be made to the construction schedule and the compensation to be paid to MECL as a result of such suspension. Customer shall be responsible for costs (a) which MECL incurred prior to the suspension or termination, and (b) which are attributable to the suspension or termination of the work, including without limitation, costs of closing out contracts and bringing the work to an orderly conclusion and costs of work necessary to ensure the safety of persons and property and the integrity of the Transmission System.

2.5.6 Progress Reports. MECL shall inform Customer, at such times as Customer reasonably requests, of the status of the construction and installation of the MECL-Owned Interconnection Facilities and Other Direct Assignment Facilities.

2.6 Testing

Prior to interconnection of the Facility to the Transmission System, MECL, at Customer's expense, shall test the MECL-Owned Interconnection Facilities, the Other Direct Assignment Facilities, and specify testing to be conducted by Customer and witness such testing of Customer's facilities, to ensure their safe and reliable operation in accordance with Good Utility Practice and shall, at Customer's expense, correct any situations contrary to Good Utility Practice.

2.7 Timely Completion

2.7.1 The estimated construction schedule is set forth in Schedule C hereto, a copy of which is attached hereto and incorporated by reference as if fully set forth herein, which Schedule C may be revised or amended in accordance with Section 26.0 of this Agreement. MECL will use commercially reasonable efforts to procure, construct, install, and test the MECL-Owned Interconnection Facilities and the Other Direct Assignment Facilities in accordance with the estimated schedule set forth in Schedule C.

2.7.2 If any of the Transmission Upgrades are not completed prior to Customer's commercial operation date, Customer may have operating studies performed, at its expense, by MECL, or its agent or delegate, to determine the maximum allowable output of the Facility, and Customer shall, at MECL's determination, be permitted to operate the Facility in accordance with such study results, provided such study results and/or operation of the Facility are not inconsistent with Good Utility Practice and do not affect the reliability or safety of the Transmission System.

SECTION 3.0 - CONTINUING OBLIGATIONS AND RESPONSIBILITIES

3.1 Interconnection Service and Transmission Service

3.1.1 MECL will provide Customer with Interconnection Service under the terms and conditions specified in this Agreement. Transmission Service, if any, will be provided pursuant to the provisions of the OATT, and any other applicable tariff. If an MECL facility must be taken out of service for any reason in connection with construction, installation or maintenance that MECL is performing at Customer's request, Customer will be responsible for the resulting Uplift Charges.

3.1.1.1 Customer agrees that, when consistent with Good Utility Practice, certain operational limits, including without limitation, scheduled maintenance and other outages of Transmission System facilities and the facilities of other transmission providers, may apply to the Generation, as determined by MECL from time to time. When practicable the System Operator will provide reasonable notice to Customer of any operational limits that may impact Customer's Generation, but no failure to provide such notice will prevent the System Operator from so limiting Customer's Generation.

3.1.2 MECL agrees to permit Customer to interconnect the Facility, for the Term of and under the terms and conditions specified in this Agreement, as long as Customer continues to operate and maintain such Facility pursuant to Good Utility Practice and is not in default under this Agreement as addressed in Section 8.0. Customer will at all times Maintain the Facility consistent with Schedule B, MECL's Generator Technical Requirement, a copy of which is attached hereto, and incorporated by reference herein as if fully set forth herein, unless any such requirement is otherwise waived in writing by MECL.

3.1.3 Customer, or its customers, is responsible for making arrangements and payments under the applicable tariffs for transmission, and ancillary services associated with the delivery of capacity and energy from the Point of Receipt.

3.1.3.1 Notwithstanding any other provision of this Agreement, nothing herein shall be construed as granting, conveying, relinquishing or foreclosing any rights to firm transmission, capacity, or transmission credits, that the Customer, or one or more of its customers, may be entitled to, now or in the future, as a result of, or otherwise associated with, the transmission capacity, if any, created by any of the facilities to be paid for by Customer under this Agreement. Any such rights to firm transmission, capacity, or transmission credits for facilities constructed under this Agreement shall be consistent with the Tariff.

3.1.4 Customer is also responsible for making arrangements and payments for Customer's

Facility Station Service requirements pursuant to applicable tariffs.

3.1.5 In the event MECL determines that any modification to Customer's existing interconnection for the Facility or any modification to such Facility requires an addition to or modification of the MECL-Owned Interconnection Facilities or MECL's Transmission System due to Good Utility Practice, MECL will notify Customer of the necessity of the addition or modification and the estimated costs to Customer as a result thereof.

3.1.6 In the event that the MECL-Owned Interconnection Facilities or the Customer-Owned Interconnection Facilities or the Facility is modified to allow other customers to be served from said MECL-Owned Interconnection Facilities, said MECL-Owned Interconnection Facilities, or portion thereof serving additional customers in addition to Customer, shall no longer be considered to solely benefit Customer. If said facilities are no longer considered to solely benefit Customer, Customer would be entitled to a refund of a portion of the contribution-in-aid-of-construction if additional development occurs such that use by others including MECL commences within 7 years from the Commercial Operation Date of the Customer's project. Refunds are non-interest bearing and will be made either on request from the developer or by MECL automatically during the seventh year following the Commercial Operation Date. The refund amount will first be collected by MECL from the additional development. The total amount of the refund will be the proportion of the installed capacity used by others including MECL, the Transmission Provider, divided by the total installed capacity of the developer plus others including MECL on the Direct Assignment Facilities multiplied by the common usage portion of the contribution-in-aid-of construction of the project.

3.1.7 Consistent with Good Utility Practice, Customer will comply with all applicable standards and requirements, including, without limitation, maintenance outage coordination, voltage schedules, generator power factor, control and reporting of output and line flow data and major equipment status, and metering accuracy. Customer will also be obligated to comply with the System Operator's directives regarding operation during Emergency conditions.

3.2 Licence and Access Rights

3.2.1 The Point of Interconnection and ownership points for the Interconnection Facilities and the Transmission System are set forth in Schedule A.

3.2.2 Customer hereby grants, without cost to MECL, a licence (the Licence) to permit MECL to have such access to Customer's property as is reasonably necessary for MECL to Maintain its facilities and equipment and the Transmission System and to exercise its rights and carry out its obligations under this Agreement; provided, however, that when exercising such access rights, MECL (i) provides Customer with as much advance notice as is practical under the circumstances, (ii) will not unreasonably disrupt or interfere with the normal operations of Customer's business, (iii) adheres to the more stringent of (a) Customer's safety rules or (b) MECL's safety rules, and (iv) acts in a manner not inconsistent with Good Utility Practice. Customer will, at its sole cost and expense, execute such documents as MECL may require to enable it to establish record evidence of such Licence. For the purposes of this Section 3.2, MECL's facilities and equipment will include, without limitation, all of MECL's metering, substation, terminals, communication, transmission and Secondary Systems facilities, suitable and sufficient meters, protective equipment, poles, towers, pipes, ducts, conduits, raceways, manholes, hand holes, riser poles, foundations, anchors, guys, braces, fittings, crossarms, wires, cables, and appurtenances for the transmission of energy, control signals, and communications located from time to time on Customer's property.

3.2.3 MECL hereby grants, without cost to Customer, a licence to permit Customer to have such access to Customer's facilities on MECL's property as is reasonably necessary and appropriate for Customer to Maintain the Facility and the Customer-Owned Interconnection Facilities in accordance with the terms and conditions of this Agreement and to exercise its rights and carry out its obligations under this Agreement.

3.2.3.1 When exercising such access rights, Customer shall (a) provide MECL with as much advance notice as is appropriate under the circumstances, (b) not unreasonably disrupt or interfere with normal operations of MECL's business, (c) adhere to the environmental and safety rules and procedure established by MECL and all applicable environmental rules and procedures, and (d) act consistent with Good Utility Practice.

3.2.3.2 Such access rights for access inside MECL's substation or terminal shall be exercised by Customer only with supervision by MECL. Customer shall provide MECL three (3) days prior notice of a request for such supervised access to MECL's substation and MECL and Customer shall mutually agree upon the date and time of such supervised access. In addition to the aforementioned requirement, in exercising such access rights, Customer shall (a) not unreasonably disrupt or interfere with normal operations of MECL's business, (b) adhere to the environmental and safety rules and procedure established by MECL and all applicable environmental rules and procedures, (c) act consistent with Good Utility Practice, and (d) compensate MECL for the use of MECL's personnel time in supervising such substation or terminal access.

3.2.4 The Licence and access rights granted to MECL under Section 3.2.2 will remain in effect for so long as MECL's facilities and equipment remain in place. The licence and access rights granted to Customer under Section 3.2.3 will remain in effect for so long as Customer is utilizing the Facility for its intended commercial purpose. Neither Party's licence, and access rights may be revoked or terminated by the other Party and neither Party will take any action that would impede, restrict, diminish or otherwise interfere with any of the rights granted under Sections 3.2.2, 3.2.3 and this Section 3.2.4., provided each Party adheres to the provisions pertaining to access rights specified in this Agreement.

3.2.5 Notwithstanding the foregoing, should a Party decide to permanently abandon the use of any such licence and access rights or any portion of any of them, it will send to the other Party written notice of such decision and, if applicable, shall cause a release of said such licence and access right or portion thereof to be recorded in the appropriate Registry of Deeds.

3.2.6 The provisions of this Section 3.2 will survive expiration or termination of this Agreement.

3.3 Facility and Equipment Maintenance

3.3.1 Equipment Maintenance and Testing Obligations.

3.3.1.1 Customer will maintain all of its Facility equipment and Customer-Owned Interconnection Facilities connected to MECL's Transmission System and MECL will maintain all of its MECL-Owned Interconnection Facilities connected to Customer's Facility in accordance with Good Utility Practice.

3.3.1.2 Customer will submit for approval by September 30th of each year, its planned annual generator maintenance schedule for the subsequent calendar year to the System Operator. The System Operator's approval shall be based on MECL's obligation to its customers for reliability of the MECL System consistent with Good Utility Practice. Once approved by the System Operator, said schedule shall be binding on both Parties. Any subsequent changes to this schedule must be approved by the System Operator. Customer will also furnish the System Operator with a non-binding five (5) year projected generator maintenance schedule by September 30th of each year for the subsequent five calendar years.

3.3.1.3 Upon a reasonable request by MECL, Customer will, at its sole cost and expense, test, calibrate, verify or validate Customer's telemetering, data acquisition, protective relay, control equipment or systems or other equipment or software pursuant to Good Utility

Practice, consistent with the requirements of Schedule B, and consistent with Customer's obligation to maintain its equipment and facilities, or for the purpose of trouble shooting problems on interconnected facilities.

3.3.1.4 Subject to Section 3.6.1, Customer will supply MECL, upon MECL's reasonable request and at Customer's sole cost and expense, with copies of inspection reports, installation and maintenance documents, test and calibration records, verifications and validations of the telemetering, data acquisition, protective relay, or any software or other equipment that comprises or pertains to the Facility.

3.4 New Construction or Modifications to MECL's Transmission System

3.4.1 Unless otherwise required by law, regulation, or Good Utility Practice, MECL will not be required at any time to upgrade or otherwise modify the Transmission System or Interconnection Facilities.

3.4.2 MECL may undertake additions, modifications, or replacements of its Transmission System including, without limitation, MECL-Owned Interconnection Facilities. If such additions, modifications, or replacements might reasonably be expected to affect the Customer's operation of the Facility, as reasonably determined by MECL, MECL will, if the circumstances permit, provide thirty (30) days written notice to Customer prior to undertaking such additions, modifications, or replacements.

3.4.3 At the request of MECL, acting in accordance with Good Utility Practice, the Customer, at its expense, will modify the Customer-Owned Interconnection Facilities and the Facility to conform with additions, modifications, or replacements of the Transmission System or MECL-Owned Interconnection Facilities.

3.4.4 Customer may install, construct or modify the Facility or Customer-Owned Interconnection Facilities pursuant to the terms and conditions of this Agreement and applicable rules and regulations of MECL, NERC, NPCC, or other entity having jurisdictional authority over any such modifications and in accordance with Good Utility Practice.

3.4.5 Before Customer may install, construct or modify the Facility in any manner that changes the electrical characteristics of the Facility or modifies the Facility's Primary electrical or associated protective equipment or its Interconnection Facilities in any manner that could reasonably be expected to affect MECL's ability to: (a) meet its service obligations under this Agreement, or (b) meet its service obligations to any MECL customer as both (a) and (b) are determined by MECL in its sole discretion exercised in a nondiscriminatory manner, Customer will be required to (1) provide MECL with all drawings, plans, schematics, specifications and all other documentation associated with the proposed addition or modification at least sixty (60) days prior to the date upon which Customer would like to implement such installations, construction or modification; and, (2) receive MECL's prior written approval, which approval shall not be unreasonably withheld.

MECL reserves the right to require a review period that is longer than sixty (60) days, if required by MECL, in its sole discretion, to assess Customer's proposed modifications. Customer will not conduct any such installation, construction or modification described in Section 3.4.4 or this Section 3.4.5 without MECL prior written approval. MECL will not unreasonably withhold or delay such approval. MECL's review and/or approval of Customer's drawings, plans, schematics, specifications and other documentation associated with a proposed installation, construction or modification will be construed neither as confirming nor as endorsing the design, nor as any warranty as to fitness, safety, durability or reliability of the installation, construction or modification. MECL will not, by reason of such review or failure to review, be responsible for the specifications, strength, design detail, adequacy, capacity, or any other technical aspect of Customer's equipment, nor will MECL's acceptance be deemed to be an endorsement, verification, or approval of Customer's equipment. Customer will reimburse MECL for any and all reasonable costs and expenses that MECL incurs in accordance with Good

Utility Practice to review such drawings, plans, schematics, specifications or other documentation.

3.4.6 For new generation installations or modifications that would reasonably be expected to impact MECL's Transmission System, Customer agrees to comply with Good Utility Practice and, as to the portion of Customer’s Facility or Customer-Owned Interconnection Facilities being modified, with the MECL's Generator Technical Requirements set forth in Schedule B.

3.4.7 Financial Obligations Associated with Incremental Transmission Investment. If at any time subsequent to the completion of the construction of the facilities initially constructed to accommodate Customer’s interconnection, as set forth in Schedule A upon execution of this Agreement, Customer modifies the Facility in a manner that affects the electrical characteristics of the electricity produced by the Facility, including a change in MVA capability, MW capability, MVAr capability, frequency or voltage; and (1) MECL is required to invest in any new transmission facilities or upgrades to existing transmission facilities as a result of such modification to maintain the Facility’s interconnection, or (2) MECL incurs any other costs associated with new transmission facility additions or upgrades that are attributable to modifications to the Facility, Customer is responsible for all costs and expenses associated with such investment in accordance with Section 5 of this Agreement, including, without limitation, Uplift Charges as described in Section 3.1.1 hereof, provided, however, that MECL shall refund to Customer such costs to the extent that such responsibility is inconsistent with any law or regulation.

3.4.7.1 MECL will modify the MECL-Owned Interconnection Facilities as may be required by Good Utility Practice or to conform with additions, modifications, or replacements of MECL’s Transmission System, which additions, modifications or replacements are consistent with Good Utility Practice. Without prejudice to Customer’s right to challenge that it is not responsible for such costs, Customer will reimburse MECL for all costs and expenses associated with such modifications and all related costs, in accordance with Section 5 of this Agreement, unless collected under a tariff or directly assigned to one or more third parties.

3.4.8 Financial Obligations Associated with Other Investments. If any entity other than MECL is required at any time to invest in any new facilities or upgrades to any existing facilities to interconnect, or accommodate the output of, the Facility, or such other entity determines that any new facilities or upgrades to existing facilities are attributable to the Facility, Customer will be responsible for making payment arrangements with such entity for any costs associated with or otherwise related to any such new or upgraded facilities.

3.4.9 Notwithstanding anything to the contrary set forth herein, all work performed in connection with the construction, installation, or modifications to the Facility that requires the performance of any activities on, or which may physically affect, MECL's Transmission System or MECL-Owned Interconnection Facilities, or any part thereof, will be performed only by the Customer (or by contractors selected by the Customer), subject to the approval of MECL, which will not be unreasonably withheld.

3.5 Inspections

3.5.1 General. Each Party, at its own cost and expense (with the exception of periodic testing and inspection, as specifically provided for in Schedule B) has the right, but not the obligation, to inspect or observe the operations and maintenance activities, equipment tests, installation, construction, or other modifications to the other Party's equipment, systems, or facilities located at the Facility or any other substation or terminal being modified pursuant to this Agreement, which might reasonably be expected to affect the observing Party's operations. The Party desiring to inspect or observe will notify the other Party in accordance with the notification procedures set forth in Section 3.13.

3.5.2 If the Party inspecting such equipment, systems, or facilities observes any deficiencies or defects, which might reasonably be expected to adversely impact the operations of the inspecting Party, the inspecting Party will so notify the other Party, and said Party will make any corrections necessitated by Good Utility Practice. Notwithstanding the foregoing, the inspecting Party shall have no liability whatsoever for any failure to give such notice, it being agreed that the owning Party will be fully responsible and liable for all such activities, tests, installation, construction or modification.

3.6 Information Reporting Obligations

3.6.1 Customer's obligations to provide information, reports, or data to MECL is subject to the following limitations:

a. Such information, reports, or data shall be subject to Section 7.1;

b. Customer shall be required to provide such information, reports or data only to the extent MECL reasonably requires such information, reports, or data to operate, Maintain, or plan the Transmission System or the regional network pursuant to Good Utility Practice;

c. MECL will request information, reports, and data from Customer on a basis that is not unduly discriminatory with respect to generators interconnected to the Transmission System , as necessary in MECL's judgement, for the purposes set forth in clause (d) below;

d. MECL will use any information, reports, or data provided by Customer pursuant to this Agreement only for the purposes of operating, Maintaining, reporting on compliance and planning the Transmission System or the regional network pursuant to Good Utility Practice; and

e. if and to the extent that any of the functions for which MECL requires certain information, reports, or data is no longer performed by MECL, which function has been adequately assumed by another entity such as a System Operator, Customer's provision of such information, reports, or data to the System Operator shall satisfy its corresponding obligation under this Agreement.

If Customer believes that any information, report, or data requested by MECL is excluded under any of the foregoing limitations, it will nevertheless provide the information, report or data pending resolution of the dispute under Section 13 if such information, report or data, in MECL's judgment: (i) constitutes information gathered through the means described in Section 3.6.4 or otherwise comprises real time generating information; (ii) is required as a result of, or to enable MECL, in a timely fashion, to respond to or prevent, any Emergency; (iii) is required to enable MECL in a timely fashion to Maintain the safety, reliability, stability, and integrity of the Transmission System, or to avoid endangering life or property; or (iv) is otherwise required by MECL (before a dispute between the Parties regarding the appropriateness of MECL's request can be resolved) in order for MECL to operate, Maintain or plan the Transmission System, pursuant to Good Utility Practice. The Parties agree to cooperate in good faith to expedite the resolution of any disputes arising under this Section 3.6.1.

3.6.2 Subject to Section 3.6.1, in order to maintain Interconnection Service, Customer will promptly provide MECL, at Customer's sole expense, with all information in Customer's possession which could reasonably be expected to impact MECL's Transmission System and which is necessary for MECL to satisfy any reporting obligations it may have to NPCC, NERC, or a future regional System Operator.

3.6.3 Subject to Section 3.6.1, Customer will supply to MECL, at Customer's sole cost and expense, accurate, complete, and reliable information in response to any MECL requests for data or information necessary for operations, maintenance, planning, or regulatory requirements and analysis of the Transmission System. Such information may include metered values for MW, KVAr, voltage, current, amp, frequency, breaker status indication, or any other information reasonably required by MECL for reliable operation of the Transmission System pursuant to Good Utility Practice.

3.6.4 Subject to Section 3.6.1, information pertaining to generation and transmission operating parameters will be gathered by Customer, at Customer's sole cost and expense, for electronic transmittal to MECL using: RTU equipment, interval metering or other equivalent devices. File formats, communication protocols, frequency and timing of data transfers must be acceptable to MECL. Any cost to modify MECL's systems to accept the electronic transmittals will be at the sole cost and expense of Customer.

3.6.5 Notwithstanding the foregoing provisions of this Section 3.6, MECL may request and Customer will promptly provide, at Customer's sole cost and expense, such other information and data that MECL may reasonably require to carry out MECL's responsibilities and enforce MECL's rights under this Agreement.

3.6.6 Notwithstanding the foregoing provisions of this Section 3.6, Customer may reasonably request and MECL will provide, as promptly as reasonably practicable and at Customer's sole cost and expense, such other information and data that Customer may reasonably require to carry out Customer's responsibilities and enforce Customer's rights under this Agreement. This provision applies to information already in MECL's possession and not reasonably available from an alternate source. Nothing in this section shall obligate MECL to undertake any data collection, or to perform any studies, to satisfy Customer's request.

3.7 Local Services

3.7.1 General. The Parties agree that, due to the integration of certain protection and control schemes, revenue metering applications, and communication networks, it may be necessary to provide each other with the services set forth in Sections 3.8 and 3.9 below.

3.7.1.1 The Parties will use commercially reasonable efforts to ensure that services provided by one Party to the other Party pursuant to Sections 3.8 and 3.9 will be available at all times during the term of this Agreement. Notwithstanding the foregoing, either Party may change the services set forth in Sections 3.8 and 3.9, provided that the quality, reliability and integrity of the replacement services is equivalent to the existing services.

3.7.1.2 Neither Party will terminate, during the term of this Agreement, any services set forth in Sections 3.8 and 3.9 that it agrees to provide to the other Party.

3.7.2 Temporary Suspension of Services.

3.7.2.1 The Party providing the services set forth in Sections 3.8 and 3.9 below will notify and obtain approval from the affected Party of any scheduled temporary suspension of services at least (5) five working days (if practical under the circumstances) in advance of such suspension. Such notification shall include an estimate of how long such suspension is likely to last and when the Party anticipates a return to normal conditions.

3.7.2.2 In the event of any unscheduled or forced suspension of the services set forth in Sections 3.8 and 3.9 below, the providing Party will promptly notify the other Party first orally and then in writing. The providing Party will use all reasonable efforts to minimize the duration of said suspension.

3.7.2.3 The Parties agree to use commercially reasonable efforts to complete any repairs, modifications or corrections that are necessary to restore suspended services pursuant to Sections 3.8 and 3.9 below to the other Party as soon as reasonably practicable.

3.8 MECL Provided Local Services

3.8.0 MECL Provided Local Service. MECL will provide the following local services.

3.8.1 Revenue Metering. Metering will be by meters and metering devices as set forth in Schedule D. The Customer will compensate MECL for metering expenses in accordance with Schedule D. MECL will maintain, repair, or replace all Revenue Meters, conduct meter accuracy and tolerance tests, and prepare all calibration certificates required for all meters that measures energy transfers between the Customer and MECL. Said testing and calibration of meters shall be in accordance Measurement Canada standards. The Customer may request that MECL provide to the Customer a copy of the calibration certificate or other pertinent documentation. Any non-routine replacement of meters and associated equipment will be billed to Customer and will be at Customer's sole cost and expense. Any meter upgrades will be at Customer's sole cost and expense. All Revenue Meters will be sealed, and the seal will be broken only by MECL.

3.8.2 The Parties agree that if the metering equipment and the Point of Receipt are not at the same location, electrically, the measured quantities will be compensated if requested by either Party, as set forth in Schedule D, to record delivery of electricity in a manner that accounts for energy losses occurring between the Metering Point and the Point of Receipt both when the generating unit is delivering energy to MECL and when MECL is delivering station service power to Customer. In the event of a change of the Metering Point or Point of Receipt, the loss compensation in Schedule D, will be adjusted by MECL.

Subject to the provisions of the Canadian Electricity and Gas Inspection Act, if at any time, any meter is found to be inaccurate by more than 1%, or other metering equipment is found to be outside its approved nameplate accuracy ratings, MECL will cause such metering equipment to be made accurate or replaced at the Customer's expense. Notwithstanding that a meter inaccuracy may be less than 3% metering disputes will be resolved in accordance with the provisions of the Electricity and Gas Inspection Act. Compensation for commercial implications of said metering inaccuracies will be dealt with outside of this agreement and pursuant to the pertinent governing documents such as market rules, tariffs, and contracts. Each Party will comply with any reasonable request of the other concerning the testing, calibration or sealing of meters, the presence of a representative of the other Party when the seals are broken, and other matters affecting the accuracy of measurement. MECL shall, when practicable, provide Customer with five (5) days' notice of such testing, calibration or adjustment and shall allow Customer to witness the same. If either Party believes that there has been a meter inaccuracy, failure or stoppage, it will promptly notify the other.

3.8.4 Facility Station Service. If MECL furnishes AC electric service and/or Transmission Service to Customer, this service will be metered, and Customer will pay for this service at the rates in effect at the time, pursuant to applicable tariffs, as approved by IRAC or other regulatory agency having jurisdictional authority.

3.9 Customer Provided Local Services

3.9.1 All data collected by Customer-owned RTUs at Customer's facilities, will be made available to MECL at no cost to MECL. All equipment used for RTUs and other data collection or transmission will be approved by MECL, whose approval will not be unreasonably withheld. Customer is responsible for all costs and expenses to install and maintain Supervisory Control and Data Acquisition (SCADA) communications between the utility computer in Charlottetown, Prince Edward Island and Customer's RTU at Customer's Facility.

3.9.2 Customer will, at Customer's sole cost and expense, maintain communication facilities and the RTU for continuous operations by the System Operator to monitor and control the status of the power system.

3.9.3 Customer will provide supervisory control and monitoring equipment, at Customer's sole cost and expense, as reasonably required to enable the System Operator to activate the dispatch of Generation, dispatch of reactive power, and generation rejection schemes, as specified in Schedule B, and to enable the System Operator to observe and monitor the power system. In addition, to the extent the Customer provides optional ancillary services the Customer will provide supervisory control and monitoring equipment, at Customer's sole cost and expense, as required for MECL to facilitate the provision of such services. Other orders may be given from time to time by the System Operator in an Emergency. Customer will follow all such orders issued by the System Operator; provided, however, that nothing herein shall be construed as limiting the right of Customer to be compensated for providing any interconnected operation services, or for responding to any dispatch command pursuant to mutually agreed terms or pursuant to applicable settlement rules and procedures as may be implemented in Prince Edward Island and as may be amended from time to time.

3.9.4 Line Operation Information. MECL will require remote access to site specific line operations information at Customer's facilities. Customer will make such information available to MECL at no cost, as permitted in accordance with the Standards of Conduct in Attachment L of MECL's OATT.

3.9.5 Voice Communications. Customer will, at Customer's sole expense, provide and maintain a dedicated telephone circuit linking the Facility to the System Operator for dispatching and operational communications.

3.10 Emergency Procedures

3.10.1 MECL will provide Customer with prompt oral notification by telephone of Transmission System Emergencies which may reasonably be expected to affect Customer's operation of its facilities, and Customer will provide MECL with prompt oral notification by telephone of generation and interconnection equipment Emergencies which may reasonably be expected to affect MECL's operations. Said telephone notifications will be followed with a written report within two Business Days where practicable, describing the Emergency event and the actions taken by MECL and/or the Customer.

3.10.2 If a Party determines in its good faith judgment that an Emergency exists which endangers or could endanger life or property, the Party recognizing the problem will take such action as may be reasonable and necessary to prevent, avoid, or mitigate injury, danger, or loss. If, however, the Emergency involves transmission, Customer will, to the extent practicable, notify the System Operator prior to performing any switching operations.

3.10.3 Customer and MECL may each, consistent with Good Utility Practice, have the System Operator take whatever actions or inactions it deems necessary during an Emergency, without liability to the other Party for such actions or inactions, to: (i) preserve the safety of the public and personnel of Customer, MECL and their contractors; (ii) preserve the integrity of the Transmission System or Customer's Facility or other equipment or property; (iii) limit or prevent damage; or (iv) expedite restoration of service.

3.11 Service Interruptions

If the System Operator in accordance with Good Utility Practice determines, that operation of Customer's equipment is having, or reasonably could be expected to have, an adverse impact on the quality of service or interfere with the safe and reliable operation of the Transmission System or that such operation otherwise has, or reasonably could be expected to, lead to an Emergency, MECL may discontinue Interconnection Service. Unless the System Operator perceives that an emergency exists or the risk of one is imminent, MECL will give Customer reasonable notice of its intention to discontinue Interconnection Service and, to the extent practical, allow Customer suitable time to remove or mitigate the situation. MECL's judgment with regard to the interruption of service under this Section 3.11 shall be made pursuant to Good Utility Practice and on a non-discriminatory basis with respect to generators connected to the Transmission System. In the case of such interruption, MECL will immediately confer with Customer regarding the conditions causing such interruption and its recommendation concerning timely correction thereof. MECL may discontinue Interconnection Service only for so long as is necessary under Good Utility Practice and, if such discontinuation of Interconnection Service does not stabilize or mitigate the situation, then MECL shall use Good Utility Practice to restore the provision of Interconnection Service to Customer. In the event Interconnection Service is interrupted under this Section due to Customer's failure to operate and maintain the Facility pursuant to Good Utility Practice, Customer will compensate MECL for all costs incurred by MECL attributable to the interruption and restoration of Interconnection Service.

3.12 Unit Availability Notification

3.12.1 For unplanned events other than forced outages that affect Facility availability, the Customer will, to the extent feasible, provide immediate notice to the System Operator so that the System Operator can coordinate the outage to maintain system reliability.

3.12.2 For forced outages, the Customer will immediately notify the System Operator of the Facility's temporary interruption of Generation; and it will provide the System Operator, as soon as practicable, with a schedule of when Generation will be resumed.

3.13 Maintenance Notification and Coordination

3.13.1 Scheduled Transmission System Maintenance. MECL will consult with Customer regarding timing of relevant scheduled maintenance of MECL's transmission facilities. MECL will, to the extent practicable, schedule any testing, shutdown, or withdrawal of said transmission facilities to coincide with Customer's scheduled outages.

3.13.1.1 If Customer desires MECL to perform maintenance during a time period other than a scheduled outage, MECL will use commercially reasonable efforts to meet Customer's request as long as it will not reasonably be expected to have an adverse economic impact upon MECL or MECL's other Customers. If Customer's request has, or is reasonably expected, as determined by MECL in its sole judgement, to have, an adverse economic impact upon MECL, and Customer is willing to reimburse MECL for the costs incurred by MECL as a result of the rescheduling, MECL shall use commercially reasonable efforts to comply with Customer's request.

3.13.1.2 In the event MECL is unable to schedule an outage of its facilities to coincide with Customer's schedule, MECL shall use reasonable efforts to notify Customer, in advance, of reasons for the outage, the time scheduled for it to take place, and its expected duration. MECL will use commercially reasonable efforts to restore its facilities to service as soon as reasonably practicable.

3.13.1.3 If in the judgment of the System Operator, it is determined prior to the commencement of any planned outage that Customer's Generation is required to operate during planned maintenance, Customer will to the maximum extent financially and technically practicable, comply with such requests. Any compensation for must run generation, if any, will be pursuant to MECL business practices, as may be amended from time to time and in no event will MECL be liable for any such compensation, unless specifically required by approved business practices.

3.13.2 Local Routine Inspection and Maintenance. MECL will provide at least eight (8) hours advance notice to Customer's Facility operator (or equivalent) by telephone before MECL's personnel enter Customer's facilities for routine measurements, routine inspections, and routine meter reads.

3.14 Safety

3.14.1 General. Subject to Section 9.0, the Parties agree to be solely responsible for and assume all liability for the safety and supervision of their own employees, agents, representatives, and subcontractors.

3.14.1.1 The Parties agree that all work performed by either Party which could reasonably be expected to affect the operations of the other Party will be performed in accordance with all applicable laws, rules, and regulations pertaining to the safety of persons or property, including without limitation, compliance with the safety regulations and standards adopted under the Occupational Health and Safety Act of Prince Edward Island as amended from time to time, the Canadian Electrical Safety Code as amended from time to time and Good Utility Practice.

3.14.2 Switching and Tagging Procedures. Each Party will comply with MECL's Standard Protection Code in existence on the date of this Interconnection Agreement and as they may be modified by MECL from time to time, at all utility Primary and Secondary Systems equipment interconnection or demarcation points. MECL will notify Customer of any changes in MECL's Standard Protection Code.

3.14.2.1 Customer, in accordance with MECL's Standard Protection Code, will be responsible for arranging and paying for MECL approved operator training, testing and certification. Qualified personnel will be eligible for inclusion on the List of Qualified Persons but will not be eligible to perform Switching and Tagging functions on MECL owned equipment unless under the direct supervision of a qualified MECL employee.

3.15 Environmental Compliance and Procedures

3.15.1 The Parties will comply with all applicable Environmental Laws which impact the ability of the Parties to meet their obligations under this Agreement.

3.15.2 The Parties will comply with all local notification and response procedures required for all applicable environmental and safety matters which impact the ability of the Parties to meet their obligations under this Agreement.

SECTION 4.0 - OPERATIONS

4.1 General

The Parties agree to operate all equipment that could reasonably be expected to have a material impact on the operations of the other Party in a safe and efficient manner and in accordance with all applicable federal, provincial, and local laws, and all applicable rules, regulations, and codes of governmental agencies, Good Utility Practice, and the terms of this Agreement.

4.2 Customer's Operating Obligations

4.2.1 Except in an Emergency, Customer will request permission from the System Operator (or such Party designated by the System Operator) prior to opening or closing switching devices at the designated Point of Interconnection, identified in Schedule A, in accordance with applicable switching and operations procedures, which permission will not be unreasonably withheld or delayed. If Customer opens or closes a switching device in an Emergency, without requesting permission from the System Operator, Customer shall notify the System Operator immediately after taking such action.

4.2.1.1 Customer will carry out all switching orders from the System Operator in a timely manner.

4.2.1.2 Customer will keep MECL advised of its generator's capabilities of participation in system restoration or if it has black start capability in accordance with Schedule E (Black Start Criteria).

4.2.2 Voltage or Reactive Control Requirements. Unless otherwise agreed to by the Parties, Customer will operate its Facility with automatic voltage regulators consistent with Schedule B. The voltage regulators will control voltage at the Points of Interconnection when the Facility is operating consistent with the range of voltage and reactive capability set forth in Schedule H, a current copy of which is attached hereto and incorporated by reference as if fully set forth herein. Compensation to Customer, if any, for providing such reactive power and voltage support will be in accordance with applicable provisions of the Tariff or any applicable business practices.

4.2.2.1 When the Facility is available, Customer shall, to the extent technically practicable, comply with requests by the System Operator to deactivate the automatic voltage regulator and to adjust reactive power up to the limits defined in Schedule H, attached hereto and which is incorporated by reference as if fully set forth herein, only if such requests are required by Good Utility Practice and are necessary to maintain the safety or reliability of the Transmission System and provided further that nothing herein shall be construed as limiting the right of Customer to be compensated for providing any interconnected operation services, including but not limited to reactive power or VAR support, pursuant to mutually agreed terms or pursuant to applicable provisions of any IRAC-approved tariff of which MECL has received prior written notice, MECL's OATT, or any business practices and procedures IRAC may approve for implementation in Prince Edward Island, as applicable, and as may be amended from time to time.

4.2.2.2 If Customer's Facility is operating, and Customer fails to operate the Facility in accordance with Section 4.2.2, MECL may, in its reasonable discretion, provide written notice to Customer of such condition. If Customer does not commence appropriate action to correct such condition within seven (7) days of receipt of such notice or such earlier date reasonably specified by MECL, MECL may, in the event of or in order to prevent an Emergency, take necessary action at Customer's expense, to correct such condition, including the installation of capacitor banks or other reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Facility. Nothing in this Section will obligate Customer to operate the Facility beyond its design or actual capability. If Customer fails to operate the Facility as required by Section 4.2.2, MECL may open the interconnection between Customer and MECL, only if required by Good Utility Practice and necessary to maintain the safety and reliability of the Transmission System. Unless prohibited from doing so by the exercise of Good Utility Practice, MECL will endeavor to provide the Customer with as much notice as practicable of MECL's intent to take such action, and with an opportunity to correct the condition, before opening the interconnection as described in the preceding sentence.

4.2.2.3 Customer will promptly notify the System Operator, to the extent required by the System Operator, if the Facility reaches a VAr limit, if there is any deviation from the assigned voltage schedule, or if any automatic voltage regulator is removed from or restored to service.

4.2.2.4 In addition to voltage regulation, Customer will adhere to the System Operator's system restoration plans and blackstart criteria, if applicable, as amended from time to time. Blackstart Criteria are attached hereto as Schedule E.

4.2.2.5 In addition to the above, Customer will maintain its automatic frequency response controls (governor), as specified in Schedule B, in service unless otherwise agreed to by the System Operator.

4.2.3 If MECL determines that any of Customer-Owned Interconnection Facilities or associated equipment fail to perform as designed, or that Customer has failed to perform testing or maintenance of such equipment in accordance with the terms of this Agreement and such failure has, or could reasonably be expected to adversely impact operation of the Transmission System, MECL shall notify Customer in writing of such failure, its recommended corrective action, and its recommended deadline for the completion of such corrective actions. Within ten (10) days or the deadline reasonably specified by MECL, Customer must demonstrate to MECL's satisfaction that Customer has initiated such corrective action as is necessitated by Good Utility Practice. If Customer fails to demonstrate within such time period to MECL's satisfaction that it has initiated or completed such corrective action as is necessitated by Good Utility

Practice or that no corrective action is necessitated by Good Utility Practice, MECL may open the interconnection between Customer and MECL; provided, however, that MECL may open the interconnection only for so long as is necessary under Good Utility Practice.

4.2.3.1 If MECL determines that a modification to any of Customer-Owned Interconnection Facilities or associated equipment has been made so that performance is not as originally approved by MECL and such performance has, or could reasonably be expected to adversely impact operation of the Transmission System, MECL may, if such condition is not corrected after giving Customer as much advance notice to correct the condition as is practicable under the circumstances, open the interconnection between Customer and MECL; provided, however, that MECL may open the interconnection only for so long as is necessary under Good Utility Practice.

4.2.3.2 Notwithstanding anything to the contrary in this Agreement, MECL may immediately disconnect the Facility from MECL's Transmission System, if MECL perceives, consistent with Good Utility Practice, that the operation of Customer's equipment or Facility presents an imminent threat to the reliable and safe operation of MECL's Transmission System; provided, however that MECL may disconnect the Facility for so long as is necessary under Good Utility Practice.

4.2.4 Customer acknowledges that the System Operator has the right to require reduced or increased generation and/or select for generation rejection as specified in Schedule B in accordance with this Agreement. Customer will promptly comply with all such requests of the System Operator, provided such requests of the System Operator are consistent with Good Utility Practice and are made on non-discriminatory basis and provided further that nothing herein shall be construed as limiting the right of Customer to be compensated for responding to any dispatch command pursuant to mutually agreed terms or pursuant to applicable provisions of MECL's OATT, or business practices in Prince Edward Island, as applicable, and as may be amended from time to time.

4.3 MECL's Operating Obligations

4.3.1 General. All operations pertaining to Customer's generation, including start-up, shutdown and determination of hourly generation, will be coordinated by the System Operator, with the Customer.

4.3.2 With respect to any curtailment, interruption, reduction or disconnection permitted under this Agreement, MECL agrees that:

a. when the curtailment, interruption, reduction or disconnection can be scheduled, the System Operator will consult in advance with Customer regarding the timing of such scheduling and further notify Customer of the expected duration. The System Operator will use commercially reasonable efforts to schedule the curtailment or interruption to coincide with the scheduled outages of the Facility and, if not possible, the System Operator will use commercially reasonable efforts to schedule the curtailment or interruption during non-peak load periods. If scheduling the curtailment interruption, reduction or disconnection during non-peak load periods, or to coincide with scheduled outages of the Facility, results in increased costs to MECL, Customer agrees to reimburse MECL for such increased costs.

b. when curtailment, interruption, reduction or disconnection must be made under Emergency circumstances or other circumstances which do not allow for advance notice, the System Operator will notify the Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, reduction or disconnection and, if known, its expected duration. Upon Customer's reasonable request, telephone notification will be followed by written notification;

c. the curtailment, interruption, reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice and the System Operator will use commercially reasonable efforts to resolve any problems to allow Customer to return to a safe and reliable operating level as determined and authorized by the System Operator;

d. any such curtailment, interruption, reduction or disconnection shall be made on an equitable, non-discriminatory basis with respect to all users of the Transmission System.

4.3.3 MECL reserves the right, in accordance with Good Utility Practice, to have the System Operator specify generator requirements that impact the Transmission System, such as excitation, droop and automatic generation control, as modified from time to time on a non-discriminatory basis. Customer agrees to comply with such specifications at Customer's sole cost and expense; provided, however, nothing herein shall be construed as limiting the right of Customer to be compensated for fulfilling any such requirements pursuant to mutually agreed terms or pursuant to applicable provisions of MECL's OATT, or any approved business practices in Prince Edward Island, as applicable, and as may be amended from time to time.

SECTION 5.0 - COST RESPONSIBILITIES AND BILLING PROCEDURES

5.1 Customer's Cost Responsibility Associated with Interconnection Services

5.1.1 Customer's Continuing Annual Costs Responsibility. Customer will be responsible for all continuing costs relative to Direct Assignment Facilities, Other Direct Assignment Facilities, and Revenue Meters constructed or installed on Customer's behalf, as set forth in Schedule D (with respect to Revenue Meters) and Schedule I (with respect to all other Direct Assignment Facilities). A copy of Schedule D and Schedule I are attached hereto and incorporated by reference as if fully set forth herein.

5.1.1.1 Customer's Annual Costs for MECL-Owned Interconnection Facilities and Other Direct Assignment Facilities. Customer's annual cost associated with said MECL-Owned Interconnection Facilities and Other Direct Assignment Facilities will be as set forth in Schedule I. MECL will annually update the Interconnection Facilities Charges (IFSC-CR and IFSCNCR), for any new or upgraded MECL-Owned Interconnection Facilities, as applicable, by applying the formula set forth in Schedule 9 of MECL's OATT.

5.1.1.2 Customer's Annual Costs for Revenue Meters. The monthly charge for the operation, maintenance, and routine testing of MECL's metering devices and for the processing of electronically metered data, is set forth in Schedule D. MECL will annually update the annual charge for Revenue Meters, for any new or upgraded Revenue Meters, as applicable, and include charges as set forth in Schedule 9 of MECL's OATT.

5.1.2 Customer's Cost Responsibility for Design, Engineering, and Construction of Facilities. The Customer shall be responsible for the entire costs of Direct Assignment Facilities and Revenue Metering. The Customer's cost responsibility for Other Direct Assignment Facilities will be determined in accordance with Attachment K of the MECL OATT and set forth in Schedule I of this Agreement. Customer will pay MECL the Customer's proportionate share of the following charges associated with any design, engineering, procurement, construction, installation and/or testing of Direct Assignment Facilities, Other Direct Assignment Facilities, and Revenue Meters which are being or may be constructed or required pursuant to this Agreement. Reimbursable costs under this Section 5.1.2 will include, without limitation, MECL's labor costs; costs of materials and equipment; contractor costs; any taxes or governmental fees; MECL's overheads; cost of capital, and operations, maintenance, and administrative (OM&A) expenses, and other related costs.

a. Customer will pay MECL a contribution of capital in an amount equal to the cost of any such new or upgraded Direct Assignment Facilities, Revenue Metering, and Customer's proportionate share of Other Direct Assignment Facilities. The Parties intend that all payments or property transfers made by Interconnection Customer to MECL for the installation of the MECL's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with any applicable Federal and Provincial tax laws and shall not be taxable as contributions in aid of construction or otherwise under any applicable Federal and Provincial tax laws.

b. MECL shall refund to Customer any sums previously paid by Customer that MECL is collecting under the MECL OATT as payment of a contribution of capital provided that such sums are included in Section 5.1.2(a).

c. Customer will pay on a monthly basis, the amounts that MECL has expended pursuant to Section 5.1.2(a). Customer shall pay MECL for the invoiced amount as per the billing procedures described in Section 5.4.

d. All payments required under this Section 5.1.2 will be determined by MECL. Any amounts not paid by the due date shall be subject to an interest charge as described in the billing procedures in Section 5.4.

e. When Customer's properly allocated share of the actual construction costs resulting from Sections 5.1.2 are known, MECL will issue a final cost report to Customer. MECL will determine the difference between the costs already paid by Customer and the Customer's properly allocated share of the actual costs of the additions and upgrades described in Section 5.1.2. To the extent that the Customer's properly allocated share of the actual costs of the upgrades and additions exceed the cost paid by Customer, Customer will pay MECL an amount equal to the difference between the amount paid by Customer and the Customer's properly allocated share of the actual cost. To the extent the cost exceeds the Customer's properly allocated share of the actual cost, and Customer has paid the cost in full, MECL will refund the difference between the Customer's properly allocated share of the actual cost and the amount paid by Customer within thirty (30) days. Payments by the Parties pursuant to this Section 5.1.2 will be made pursuant to Section 5.6 of the Agreement within thirty (30) days of the date upon which MECL notifies Customer of the Customer's properly allocated share of the actual costs of the upgrades and additions provided, however, that MECL (i) may retain a reserve to cover any costs associated with the additions and upgrades that remain to be completed and/or that have not been invoiced and paid, and (ii) may request a deposit equal to the estimated remaining charges under this Agreement or Customer may provide other such security as is reasonably acceptable to MECL, such acceptance not to be unreasonably withheld.

f. If the Customer for whatever reason goes out of business or otherwise abandons the Facility and any incremental Transmission System Upgrades have already been partially or completely constructed the Customer will be responsible for reimbursing MECL for all of the unrecovered costs in accordance with Section 2.5.5 of the said Transmission System Upgrades that would not have been incurred by MECL but for the Facility.

5.1.2.1 Audits. Within twelve (12) months following the issuance of a final cost report pursuant to Section 5.1.2(e), Customer may audit MECL's accounts and records at the offices where such accounts and records are maintained, during normal business hours and at a time mutually agreeable to the Parties. Customer shall provide MECL fifteen (15) days prior written notice of a request to audit pursuant to this Section 5.1.2.1 and any such audit shall be limited to those portions of such accounts and records that relate to such final cost report. Any data collection for such audit conducted pursuant to this Section 5.1.2.1 shall be performed continuously until complete and Customer shall utilize commercially reasonable efforts to complete the data collection for such audit within thirty (30) days, however, in no event shall any data collection for such audit continue for more than sixty (60) days. MECL reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by Customer or its designated agent.

5.1.2.2 Under this Agreement, the Customer shall not be responsible for any costs or expenses associated with the procurement, construction, testing, operation and maintenance of any modifications or upgrades to the Transmission System undertaken that are unrelated to the Facility being interconnected to the Transmission System, including, without limitation, those undertaken in order to prevent, mitigate, or otherwise remedy conditions that existed prior to, and that otherwise would have been prevented, mitigated, or remedied regardless of the Customer's interconnection. The Customer shall be responsible for any costs or expenses associated with the procurement, construction, testing, operation and maintenance of any modification or upgrades to the Transmission System necessary in order to prevent, mitigate, or otherwise remedy conditions that result from the Facility being interconnected to the Transmission System whenever it is determined that such conditions need be prevented, mitigated, or otherwise remedied. Any refunds owed to the Customer by MECL and any payments owed to MECL by the Customer under this Section 5.1.2.2 shall be made in accordance with Section 5.1.2(e).

5.1.3 Except as specifically provided elsewhere in this Agreement, if MECL incurs any additional costs during the term hereof in connection with the modification, relocation, removal, retirement or abandonment in whole or in part of Customer's Facility or MECL-Owned Interconnection Facilities or Other Direct Assignment Facilities, Customer will reimburse MECL for all such costs on a lump sum basis or as otherwise requested by MECL pursuant to charges as established by MECL. Reimbursable costs under this Section will include, without limitation, MECL's labor costs; costs of materials and equipment; contractor costs; any taxes or governmental fees; MECL's overheads; cost of capital, and OM&A expenses, and other related costs.

5.1.4 If MECL incurs any additional costs during the term hereof in connection with the construction, maintenance and operation of MECL-Owned Interconnection Facilities and Other Direct Assignment Facilities, or if MECL is assessed any costs that are determined to be directly attributable to Customer, Customer will reimburse MECL for all such costs in accordance with Attachment K of the MECL OATT. Said construction, maintenance and operation costs include those related to facility upgrades not identified during the initial studies but determined anytime thereafter to be necessary and directly attributable to the interconnection of Customer's Facility Reimbursable costs under this Section 5.1.4 shall include, without limitation, any tax liability, the cost of acquiring land for MECL's facilities, and fees for all permits, licences, franchises, or regulatory or other approvals.

5.2 Cost Responsibilities for Local Services

5.2.1 Customer will be responsible for the costs for services provided by MECL in Section 3.8.

5.2.2 For services provided by MECL which have identified prices/rates schedules set forth herein or in applicable tariffs or rate schedules, said payment will be in accord with said schedules as in effect from time to time. For services provided by MECL which do not have identified price/rate schedules, MECL will determine such charges for any such services.

5.3 Pre-Contract Costs

MECL will invoice Customer for pre-contract costs incurred by MECL prior to the date of execution of this Agreement. Such pre-contract costs are set forth in Schedule G.

5.4 Billing Procedures

5.4.1 Promptly after the end of the each calendar month, MECL shall bill the Customer in Canadian dollars for the charge payable by the Customer in respect of such month.

Accounts shall be due and payable in Canadian dollars on the twentieth day of each month or if the twentieth day of the month is a Saturday, Sunday or statutory holiday in PEI then on the next closest working day to the twentieth day, and if not paid when due shall be subject thereafter and until paid to a per annum interest charge at a rate equal to the prime interest rate quoted by the Royal Bank, Queen Street Branch in Charlottetown plus two (2) percent (the "Interest Rate"). Such interest charge shall be compounded monthly.

5.4.2 Each invoice will delineate the month in which the services were provided, fully describe the work, equipment, or services for which the costs were or are expected to be incurred, and be itemized to reflect such work, equipment or services. All payments will be made in immediately available funds payable to the invoicing Party, or by wire transfer to a bank named by the invoicing Party.

5.5 Payment Not a Waiver

Payment of invoices by either Party will not relieve such Party from any responsibilities or obligations it has under this Agreement, nor will it constitute a waiver of any claims arising hereunder.

5.6 Billing Disputes and Adjustments of Invoices

A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Agreement or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. Notwithstanding Section 5.4, in the event an invoice or portion thereof or any other claim or adjustment arising under this Agreement is disputed, payment of the undisputed portion of the invoice shall be made when due, with notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment shall be made within two (2) business days of such resolution along with interest accrued at the interest rate from and including the due date to but excluding the date paid.

Inadvertent overpayments by Customer shall be returned upon request or deducted from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment to but excluding the date repair or deducted by the Party receiving such overpayment.

Legal or other proceedings, other than arbitration pursuant to Section 12, in respect of any dispute with respect to an invoice may not be started unless the other Party or Parties is/are notified in accordance with Section 20.2 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made. If an invoice is not rendered within twelve (12) months after the close of the month during which the invoice was rendered, the right of payment for such performance is waived.

SECTION 6.0 - DOCUMENTATION

6.1 General

6.1.1 Customer will provide MECL, and MECL will provide Customer, upon reasonable request, with appropriate documentation, consistent with Good Utility Practice, in the form of written test records, operation and maintenance procedures, drawings, material lists, or descriptions, when Customer installs or makes an alteration, change, or modification to its property, equipment, or facilities that could reasonably be expected to affect MECL, or whenever such documentation is necessary for maximizing operational efficiencies or promoting safety, reliability or environmental compliance.

6.1.2 Except to the extent set forth in Section 7 below, all documentation furnished to or obtained by MECL pursuant to this Agreement will be confidential and will be treated as proprietary information.

6.1.3 In accordance with Section 3.4.5, prior to Customer constructing, installing, or performing any modifications to equipment or portions of the Facilities that are connected to MECL's Transmission System, or that are jointly used, operated, or maintained, and such modifications could reasonably be expected to change the electrical output or electrical characteristics of such Facilities or may require modifications to be made to MECL's Transmission System, Customer will submit the proposed plans to MECL.

6.1.4 Upon completion of any modifications to equipment or facilities that are connected to MECL's Transmission System, or that will be jointly used, operated, or maintained, but no later than ninety (90) days thereafter, Customer will, at its sole cost and expense, issue "as built" drawings to MECL.

6.1.5 Customer will be responsible for its own equipment, inspections, maintenance, construction, and modifications. MECL's review of, or comments on, any document provided by Customer, will not relieve Customer of its responsibility for the correctness and adequacy of the work to be performed.

6.2 Drawings

Each Party will be responsible for drawing updates and corrections to their respective drawings of Customer-Owned Interconnection Facilities and MECL-Owned Interconnection Facilities and will provide copies to the other Party as soon as practicable thereafter.

SECTION 7.0 - CONFIDENTIALITY

7.1 Confidentiality of MECL

MECL will hold in confidence, unless compelled to disclose by judicial or administrative process or other provisions of law, any and all documents and information furnished by Customer in connection with this Agreement. Except to the extent that such information or documents are (i) generally available to the public other than as a result of a disclosure by MECL, (ii) available to MECL on a non-confidential basis prior to disclosure to MECL by Customer, or (iii) available to MECL on a non-confidential basis from a source other than Customer, provided that such source is not known, and by reasonable effort could not be known, by MECL to be bound by a confidentiality agreement with Customer or otherwise prohibited from transmitting the information to MECL by a contractual, legal or fiduciary obligation, MECL will not release or disclose such information to any other person, except to its employees, contractors and agents on a need-to-know basis, in connection with this Agreement who has not first been advised of the confidentiality provisions of this Section 7.1 and has agreed in writing to comply with such provisions. MECL will promptly notify Customer if it receives notice or otherwise concludes that the production of any information subject to this Section 7.1 is being sought under any provision of law, but MECL will have no obligation to oppose or object to any attempt to obtain such production. If Customer desires to oppose or object to such production, it will do so at its own expense. MECL may utilize information subject to this Section 7.1 in any proceeding under Section 13, or otherwise to enforce MECL's rights under this Agreement, subject to a confidentiality agreement with the participants or a protective order approved by an arbitrator or an administrative agency or court of competent jurisdiction.

7.2 Confidentiality of Customer

Customer will hold in confidence, unless compelled to disclose by judicial or administrative process or other provisions of law, any and all documents and information furnished by MECL in connection with this Agreement. Except to the extent that such information or documents are (i) generally available to the public other than as a result of a disclosure by Customer, (ii) available to Customer on a non-confidential basis prior to disclosure to Customer by MECL, or (iii) available to Customer on a non-confidential basis from a source other than MECL, provided that such source is not known, and by reasonable effort could not be known, by Customer to be bound by a confidentiality agreement with MECL or otherwise prohibited from transmitting the information to Customer by a contractual, legal or fiduciary obligation, Customer will not release or disclose such information to any other person, except its employees, contractors, or agents, on a need-to-know basis, in connection with this Agreement, who has not first been advised of the confidentiality provision of this Section 7.2 and has agreed in writing to comply with such provisions. Customer will promptly notify MECL if it receives notice or otherwise concludes that the production of any information subject to this Section 7.2 is being sought under any provision of law, but Customer will have no obligation to oppose or object to any attempt to obtain such production. If MECL desires to oppose or object to such production, it will do so at its own expense. Customer may utilize information subject to this Section 7.2 in any proceeding under Section 13, subject to a confidentiality agreement with the participants or a protective order approved by an arbitrator or an administrative agency or court of competent jurisdiction.

7.3 Remedies Regarding Confidentiality

The Parties agree that monetary damages by themselves would be inadequate to compensate a Party for the other Party's breach of its obligations under Section 7.1 or 7.2, as applicable. Each Party accordingly agrees that the other Party will be entitled to equitable relief, to the extent permitted by law, or otherwise, if the first Party breaches or threatens to breach its obligations under Section 7.1 or 7.2, as applicable.

SECTION 8.0 - DEFAULT

8.1 Default

"Event of Default" shall mean any of the following events which either (a) continues for twenty (20) days after a Party's receipt of written notice of such from the other Party or, if the event cannot be completely cured within such twenty (20) day period, (b) diligent efforts to cure the event within such twenty (20) day period have not been commenced by the Party, and the event is likely curable within sixty (60) days but is not cured within sixty (60) days after a Party's receipt of written notice of such event from the other Party:

a. The failure to pay any amount when due;

b. The failure to maintain the Facility or comply with any material term or condition of this Agreement, including but not limited to any material breach of a representation, warranty or covenant made in this Agreement;

c. If Customer: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

d. Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

e. The failure to provide licence or access rights described in Section 3.2, failure to execute any document provided for by Section 3.2, or an attempt to revoke or terminate such licence or access rights as provided under this Agreement; or

f. The failure to provide information or data as required under this Agreement.

8.1.1 In an Event of Default by Customer, MECL shall provide written notice to any Project Finance Holders that have been identified in accordance with Section 20.2. A Project Finance Holder will have the right, in accordance with Section 15.1.2, but not the obligation, to cure any default by Customer.

8.2 Upon an Event of Default

8.2.1 The non-defaulting Party will be entitled to payment of all sums due by the defaulting Party, together with an interest rate on all said amounts, until paid, at a rate of interest that is two percent (2%) greater than the Index Rate.

8.2.2 The non-defaulting Party may (1) terminate service, to the extent that termination of service does not jeopardize system reliability as determined by the System Operator; and (2) commence an action to require specific performance and exercise such other rights and remedies as it may have in equity or at law.

8.3 Performance of Obligations of a Non-performing Party

If either Party fails to carry out its obligations under this Agreement (the "Non-performing Party") and such failure could reasonably be expected to have an adverse impact on MECL's Transmission System, the MECL-Owned Interconnection Facilities, Customer-Owned Interconnection Facilities, the Facility, or the regional network, the other Party, following twenty (20) days' prior written notice to the Non-performing Party (except in cases of Emergencies in which case only such notice as will be reasonably practicable in the circumstances) may, but will not be obligated to, perform the obligations of the Non-performing Party hereunder (excluding MECL's maintenance obligations), in which case the Non-performing Party will, not later than twenty (20) days after receipt of an invoice therefore, reimburse the other Party for all costs and expenses incurred by it in performing said obligations of the Non-performing Party hereunder (including, without limitation, costs associated with its employees and the costs of appraisers, engineers, environmental consultants and other experts retained by said Party in connection with performance of obligations of the Non-performing Party), together with interest on all said amounts, until paid, at a rate of interest that is two percent (2%) greater than the Index Rate.

8.4 Collection Expenses

In the event a Party is owed any overdue amounts under the terms of this Agreement, Customer or MECL, as applicable, will pay such Party's actual costs of collection and attempted collection, including, without limitation:

a. those expenses incurred or paid to collect or attempt to collect obligations due under or pursuant to this Agreement

b. expenses of dealing with any person or entity in any bankruptcy proceeding, and

c. all out-of-pocket expenses incurred for its attorney and paralegal fees, disbursements, and costs, including the costs of attorneys, appraisers, engineers, environmental consultants and other experts that may be retained in connection with such collection efforts.

8.5 Rights Cumulative

The rights and remedies in this Section 8 and elsewhere set forth in this Agreement are cumulative and non-exclusive.

SECTION 9.0 - DAMAGE TO EQUIPMENT, FACILITIES AND PROPERTY

9.1 Customer's Responsibility

Except to the extent caused by MECL's negligence or willful misconduct, Customer will be responsible for all physical damage to or destruction of property, equipment or facilities owned by Customer or its Affiliates, regardless of who brings the claim and regardless of who caused the damage, and Customer will not seek recovery or reimbursement from MECL for such damage.

9.2 MECL's Responsibility

Except to the extent caused by Customer's negligence or willful misconduct, MECL will be responsible for all physical damage to or destruction of property, equipment or facilities owned by MECL or its Affiliates, regardless of who brings the claim and regardless of who caused the damage, and MECL will not seek recovery or reimbursement from Customer for such damage.

9.3 Disputes

Any claims by either Party against the other under Section 9 are subject to the dispute resolution process described in Section 13.

9.4 Insurance

The obligations under this Section 9.0 will not be limited in any way by any limitation on either Party's insurance, and each Party waives any subrogation which any of its insurers may have against the other Party.

SECTION 10.0 - INDEMNIFICATION

10.1 Indemnification Obligation

Subject to the limitations on and exclusions of liability set forth herein, each Party agrees to indemnify, hold harmless, and defend the other Party, its Affiliates, and their respective officers, directors, employees, agents, contractors, subcontractors, invitees and successors (collectively the Indemnitees), from and against any and all claims, liabilities, costs, damages, and expenses which may be imposed on or asserted at any time against an Indemnitee by any third party (including, without limitation, reasonable attorney and expert fees, and disbursements incurred by any Indemnitee in any action or proceeding) for or arising from damage to property, injury to or death of any person, including the other Party’s employees or any third parties (collectively, the Loss), to the extent caused wholly or in part by any act or omission, negligent or otherwise, by the indemnifying Party and/or its officers, directors, employees, agents, and subcontractors arising out of or connected with the indemnifying Party’s performance or breach of this Agreement, or the exercise by the indemnifying Party of its rights hereunder; provided, however, that no indemnification by a Party is required under this Section to the extent such Loss is caused by or results from the negligence or willful misconduct of the other Party or its Indemnitee(s). In the event that such Loss is the result of the negligence of both Parties, each Party shall be liable to the other to the extent or degree of its respective negligence, as determined by mutual agreement of both Parties, or in the absence thereof, as determined by the adjudication of comparative negligence.

10.2 Control of Indemnification

If any third party shall notify any Indemnitee of a claim with respect to any matter which may give rise to a claim for indemnification against the other Party (the Indemnifying Party) under this Section, then the Indemnitee shall notify the Indemnifying Party thereof promptly (and in any event within ten (10) Business Days after receiving any written notice from a third party). The Indemnifying Party's liability hereunder to the Indemnitee shall be reduced to the extent the Indemnifying Party is materially adversely prejudiced by the Indemnitee's failure to provide timely notice hereunder. In the event any Indemnifying Party notifies the Indemnitee within ten (10) Business Days after the Indemnitee has given notice of the matter that the Indemnifying Party is assuming the defense thereof, (i) the Indemnifying Party will defend the Indemnitee against the matter with counsel of its choice reasonably satisfactory to the Indemnitee, (ii) the Indemnitee may retain separate co-counsel at its sole cost and expense (except that the Indemnifying Party will be responsible for the fees and expenses of the separate counsel to the extent the Indemnitee reasonably concludes that the counsel the Indemnifying Party has selected has a conflict of interest), (iii) the Indemnitee will not consent to the entry of any judgment or enter into any settlement with respect to the matter without the written consent of the Indemnifying Party (which shall not be unreasonably withheld, and (iv) the Indemnifying Party will not consent to the entry of any judgment with respect to the matter, or enter into any settlement which does not include a provision whereby the plaintiff or claimant in the matter releases the Indemnitee from all liability with respect thereto, without the written consent of the Indemnitee (which shall not be unreasonably withheld). In the event the Indemnifying Party does not notify the Indemnitee within ten (10) Business Days after the Indemnitee has given notice of the matter that the Indemnifying Party is assuming the defense thereof, however, the Indemnitee may defend against the matter in any manner it may deem appropriate.

10.3 Recovery of Enforcement Costs

Notwithstanding any other provision of this Agreement, the indemnifying Party will pay all damages, settlements, expenses and costs, including Costs of investigation, court costs and reasonable attorneys' fees and costs the other Party incurs in enforcing this Section 10.0. Each Party agrees its indemnification obligation, as detailed under this Section 10.0, will survive expiration or termination of the Agreement.

SECTION 11 – INSURANCE

11.1 General

Each Party agrees to maintain at its own cost and expense, fire, liability, workers' compensation, and other forms of insurance relating to their property and facilities in the manner, and amounts, and for the durations set forth in Schedule F, a current copy of which is attached hereto and incorporated by reference as if fully set forth herein. MECL may elect to self-insure any and/or all of the obligations set forth in Schedule F.

11.2 Certificates of Insurance; Claims Made Coverage

Each Party agrees to furnish the other with certificates of insurance evidencing the insurance coverage set forth in Schedule F, and additional insured status. Each Party will provide documentation of all policies, in a form reasonably acceptable to the other Party.

11.3 Notice of Cancellation

Neither Party shall enter into a contract of insurance providing the coverage required in Schedule F unless the contract contains the following or equivalent clause: "No reduction, cancellation or expiration of the policy will be effective until thirty (30) days from the date written notice thereof is actually received except ten (10) days notice for non-payment." Upon receipt of any notice of material change, reduction, cancellation or expiration, the Party will immediately notify the other Party in accordance with Article 20.

11.4 Additional Insureds

Each Party and its Affiliates will be named as additional insureds on the general liability insurance policies required in Schedule F under this Agreement; provided, however, that to the extent that a Loss is caused by or results from the negligence, recklessness or willful misconduct of a Party and/or its Affiliates (collectively the Negligent Party), the coverages provided through being an additional insured on the other Party's policy(s) shall be secondary to any other coverage available to the Negligent Party. Each Party will waive any right of recovery against the other Party for any Loss covered by a policy of the other Party on which it has been named as an additional insured to the extent such Loss is reimbursed under such policy. Where a Party is indemnifying an Indemnitee in accordance with the provisions of this Agreement, the insurance coverages of the other Party on which the indemnifying Party has been named an additional insured shall be secondary to any other coverage available to the indemnifying Party.

11.5 Failure to Comply

Failure of either Party to comply with the foregoing insurance requirements, or the complete or partial failure of an insurance carrier to fully protect and indemnify the other Party or its Affiliates, or the inadequacy of the insurance, will not in any way lessen or affect the obligations or liabilities of each Party to the other.

11.6 Waiver of Subrogation

Each Party, on its behalf and on behalf of its Affiliates, waives any right of subrogation under its respective insurance policies for any liability it has agreed to assume under this Agreement. Evidence of this requirement will be noted on all certificates of insurance.

SECTION 12 - FORCE MAJEURE

12.1 Definition

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. Neither MECL nor the Customer will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Agreement.

12.2 Procedures

If a Party relies on the occurrence of an event or condition described above, as a basis for being excused from performance of its obligations under this Agreement, then the Party relying on the event or condition will: (i) provide prompt written notice of such Force Majeure event to the other Party giving an estimation of its expected duration and the probable impact on the performance of its obligations hereunder; (ii) exercise all reasonable efforts to continue to perform its obligations under this Agreement; (iii) expeditiously take commercially reasonable action to correct or cure the event or condition excusing performance; provided that settlement of strikes or other labor disputes will be completely within the sole discretion of the Party affected by such strike or labor dispute; (iv) exercise all reasonable efforts to mitigate or limit damages to the other Party; and (v) provide prompt notice to the other Party of the cessation of the event or condition giving rise to its excuse from performance. All performance obligations hereunder, other than any payment obligation, or any and all obligations which were incurred prior to the Force Majeure event, will be extended by a period equal to the term of the resultant delay.

SECTION 13.0 – DISPUTE RESOLUTION PROCEDURES

13.1 Internal Dispute Resolution Procedures

Any dispute between a Customer and MECL as to their rights under this Agreement shall be referred to a designated senior representative of the MECL and a senior representative of the Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) Business Days (or such other period as the Parties may agree upon) by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

13.2 External Arbitration Procedures

Any arbitration initiated under this Agreement shall be conducted before a single neutral arbitrator appointed by the parties. If the Parties fail to agree upon a single arbitrator within ten (10) Business Days of the referral of the dispute to arbitration, each party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Business Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any part to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Prince Edward Island Arbitration Act and any applicable IRAC regulations.

13.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the parties, and judgment on the aware may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Prince Edward island of Arbitration Act.

13.4 Costs

Each party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

a. The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or
b. One half of the cost of the single arbitrator jointly chosen by the Parties.

In the event that it is necessary to enforce such aware, all costs of enforcement shall be payable and paid by the party against whom such aware is enforced.

13.5 Referral of Dispute to IRAC

Notwithstanding anything contained in this Section 13, either party may:

a. Instead of proceeding through the External Arbitration Procedures outlined in Section 13.2 or 13.4 above, elect to refer a dispute directly to IRAC by filing a complaint with IRAC in the manner set out below and the decision of IRAC with respect to the matter shall be final and binding and the matter in dispute cannot thereafter proceed to the dispute resolution process; or
b. If either party is dissatisfied with the results of an arbitration decision rendered pursuant to Section 13.3, refer a complaint to IRAC for determination and the decision of IRAC with respect to the matter shall be final and binding.

Complaints filed with IRAC must be in writing and must include reasons and evidence in support of the dissatisfied party's position. A copy of the complaint, together with the supporting reasons and evidence, must be filed with the other party.

IRAC may require a complainant to provide such security for the costs incurred or to be incurred by IRAC, as it considers reasonable, and such security may be forfeited to IRAC if the complaint is not substantiated.

13.6 Enforcement of Arbitration Decision

The Arbitration Act of Prince Edward Island shall govern the procedures to apply in the enforcement of any award made pursuant to Section 13.3.

SECTION 14.0 - REPRESENTATIONS

14.1 Representations of MECL

MECL represents and warrants to Customer as follows:

14.1.1 Organization. MECL is a corporation having its head office in Charlottetown, Prince Edward Island validly existing and in good standing under the laws of the Province of Prince Edward Island and MECL has the requisite power and authority to carry on its business as now being conducted;

14.1.2 Authority Relative to this Agreement. MECL has the requisite power and authority to execute and deliver this Agreement and to carry out the actions required of it by this Agreement. The execution and delivery of this Agreement and the actions it contemplates have been duly and validly authorized by the Board of Directors of MECL, and no other corporate proceedings on the part of MECL are necessary to authorize this Agreement or to consummate the transactions contemplated hereby. The Agreement has been duly and validly executed and delivered by MECL and constitutes a legal, valid and binding Agreement of MECL enforceable against it in accordance with its terms;

14.1.3 Regulatory Approval. MECL has obtained or will obtain all approvals of, and has given or will give all notices to, any public authority that are required for MECL to execute, deliver and perform its obligations under this Agreement;

14.1.4 Compliance With Law and Agreements. MECL represents and warrants that: (i) it is not in violation of any applicable law, statute, order, rule, or regulation promulgated or judgment entered by any federal, provincial or local governmental authority, which individually or in the aggregate would adversely affect MECL's entering into or performance of its obligations under this Agreement; and (ii) its entering into and performance of its obligations under this Agreement will not give rise to any default under any agreement to which it is a party; and

14.1.5 MECL represents and warrants that it will comply with all applicable laws, rules, regulations, codes, and standards of all applicable federal, provincial, and local governmental agencies having jurisdiction over MECL or the transactions under this Agreement and with which failure to comply could reasonably be expected to have a material adverse effect on Customer.

14.2 Representations of Customer

Customer represents and warrants to MECL as follows:

14.2.1 Organization. Customer is a (INSERT TYPE OF COMPANY) organized, validly existing and in good standing under the laws of the Province of Prince Edward Island, Canada, and Customer has the requisite power and authority to carry on its business as now being conducted;

14.2.2 Authority Relative to this Agreement. Customer has the requisite power and authority to execute and deliver this Agreement and to carry out the actions required of it by this Agreement. The execution and delivery of this Agreement and the actions it contemplates have been duly authorized by proceedings on the part of Customer and no other corporate proceedings on the part of the customer are necessary to authorize this Agreement or to consummate the transactions contemplated hereby. This Agreement has been duly and validly executed and delivered by Customer and constitutes a legal, valid and binding Agreement of Customer enforceable against it in accordance with its terms;

14.2.3 Regulatory Approval. Customer has obtained all approvals of, and given all notices to, any public authority that are required for Customer to execute, deliver and perform its obligations under this Agreement;

14.2.4 Compliance with Law and Agreements. Customer represents and warrants that: (i) it is not in violation of any applicable law, statute, order, rule, or regulation promulgated or judgment entered by any federal, provincial, state, or local governmental authority, which, individually or in the aggregate, would adversely affect Customer's entering into or performance of its obligations under this Agreement; and (ii) its entering into and performance of its obligations under this Agreement will not give rise to any default under any agreement to which it is a party; and

14.2.5 Customer represents and warrants that it will comply with all applicable laws, rules, regulations, codes, and standards of all federal, state, provincial, and local governmental agencies having jurisdiction over Customer or the transactions under this Agreement and with which failure to comply could reasonably be expected to have a material adverse effect on MECL.

14.3 Representations of Both Parties

The representations in Sections 14.1.5 and 14.2.5 will continue in full force and effect for the term of this Agreement.

SECTION 15.0 - ASSIGNMENT/CHANGE IN CORPORATE IDENTITY

15.1 General

This Agreement and all of the provisions hereof will be binding upon and inure to the benefit of the Parties hereto and their respective successors and permitted assigns, but neither this Agreement nor any of the rights, interests, or obligations hereunder may be assigned, except as provided for in Section 15.1.1 or Section 15.1.2 below, by either Party hereto, without the prior written consent of the other Party, which consent will not be unreasonably withheld or delayed. Any assignment of this Agreement in violation of the foregoing will be, at the option of the non-assigning Party, void.

15.1.1 Notwithstanding anything to the contrary herein, this Agreement may, with prior written notice to MECL, be assigned by Customer, if Customer is not then in default of this Agreement as addressed in Section 8.0:

a. to any Affiliate of Customer in connection with a merger, consolidation, reorganization or other change in the organizational structure of Customer, provided that such Affiliate is the owner of all or substantially all of the Facility;

b. to any Project Finance Holder as security for amounts payable under any Project Financing; in addition, Customer or its permitted assignee may assign, transfer, pledge or otherwise dispose of its rights and interests hereunder to a lender or financial institution in connection with a collateral assignment of this Agreement for financing or refinancing purposes, including upon or pursuant to the exercise of remedies under such financing or refinancing, or by way of assignments, transfers, conveyances or dispositions in lieu thereof; provided, however, that no such assignment, transfer, pledge, or disposition will relieve or in any way discharge Customer or such assignee from the performance of its duties and obligations under this Agreement. MECL agrees to execute and deliver such documents as may be reasonably necessary to accomplish any such assignment, transfer, conveyance, pledge, or disposition of rights hereunder for purposes of the financing or refinancing of the Facility, so long as MECL's rights under this Agreement are not thereby altered, amended, diminished or otherwise impaired. Customer will reimburse MECL for its costs and expenses associated with the preparation and review of any documents reasonably necessary to effect such assignment, transfer, conveyance, pledge or disposition of rights for the financing or refinancing of the Facility.

15.1.2 Upon breach of this Agreement or any loan documents by Customer, or the insolvency of Customer, the Project Finance Holder (i) shall have the rights of Customer set forth in Section 8.0 to cure any breach of this Agreement complained of, provided the Project Finance Holder agrees to perform Customer's obligations under the Agreement during the cure period; and (ii) shall have the right to assume all rights and obligations of Customer under this Agreement, provided, that in accordance with Section 15.2, MECL consents in writing to such assumption and/or to a release of the Customer from such liability.

15.1.3 Notwithstanding anything to the contrary herein, this Agreement may, with prior written notice to Customer, be assigned by MECL to any entity(ies) in connection with a merger, consolidation, reorganization or other change in the organizational structure of MECL.

15.2 Party to Remain Responsible

Except for assignments pursuant to Section 15.1.1(b) and Section 15.1.3, no assignment, transfer, pledge, conveyance, or disposition of rights or obligations under this Agreement by a Party will relieve that Party from liability and financial responsibility for the performance thereof after any such assignment, transfer, conveyance, pledge, or disposition unless and until the transferee or assignee agrees in writing to assume the obligations and duties of that Party under this Agreement and the non-assigning Party has consented in writing to such assumption and to a release of the assigning Party from such liability.

15.3 Termination of Corporate Existence, Etc.

If Customer terminates its existence by acquisition, sale, consolidation, or otherwise, or if all or substantially all of such Customer's assets are transferred to another person or business entity, without complying with Section 15.1 above, MECL will have the right, enforceable in a court of competent jurisdiction, to enjoin the Customer’s successor from using the property in any manner that interferes with, impedes, or restricts MECL’s ability to carry out its ongoing business operations, rights and obligations.

SECTION 16.0 - SUBCONTRACTORS

16.1 Use of Subcontractors Permitted

Nothing in this Agreement will prevent the Parties from utilizing the services of subcontractors as they deem appropriate; provided, however, the Parties agree that all said subcontractors will comply with the applicable terms and conditions of this Agreement.

16.2 Party to Remain Responsible

The creation of any subcontract relationship will not relieve the hiring Party of any of its obligations under this Agreement. Each Party will be fully responsible to the other Party for the acts or omissions of any subcontractor it hires as if no subcontract had been made. Any obligation imposed by this Agreement upon either Party, where applicable, will be equally binding upon and will be construed as having application to any subcontractor.

16.3 No Limitation by Insurance

The obligations under this Section 16.0 will not be limited in any way by any limitation on subcontractor's insurance.

SECTION 17.0 - LABOUR RELATIONS

The Parties agree promptly to notify the other Party, verbally and then in writing, of any labour dispute or anticipated labour dispute which may reasonably be expected to affect the operations of the other Party.

SECTION 18.0 - INDEPENDENT CONTRACTOR STATUS

Nothing in this Agreement will be construed as creating any relationship between MECL and Customer other than that of independent contractors.

SECTION 19.0 - LIMITATION OF LIABILITY

19.1 Operating Liability Limitations

Except in cases of gross negligence or reckless or willful misconduct and except as otherwise provided in this Agreement, under no circumstances will a Party be liable for any cost, expense, loss or damage, including, without limitation, foregone compensation, lost opportunity cost or any operating cost associated with the required reduced output of the Facility, including those resulting from or associated with any interruption, discontinuance, curtailment, or suspension of Interconnection Service; disconnection of the Facility from MECL's Transmission System; forced or planned outages of MECL's facilities or the facilities of others; electrical transients, irregular or defective service, including, without limitation, short circuits (faults); or requests by the System Operator to increase or decrease Customer's Generation or make other operational changes at the Facility; provided, however, that nothing herein shall be construed as limiting the right of Customer to be compensated for any such operating costs pursuant to mutually agreed terms or pursuant to applicable provisions of MECL's OATT, or any market settlement rules and procedures approved for implementation in Prince Edward Island.

19.2 Consequential Damages

Notwithstanding any other provision of this Agreement, except to the extent provided for in Section 10, neither MECL nor Customer, nor their Affiliates, successors or assigns, nor any of their respective officers, directors, agents or employees, will be liable to the other Party or its Affiliates, successor or assigns, or any of their respective officers, directors, agents or employees, for claims, suits, actions or causes of action, or otherwise, for incidental, punitive, special, indirect, multiple or consequential damages (including attorneys' fees and other litigation costs, or claims for lost profits or revenues) connected with or resulting from performance or non-performance of this Agreement, or any actions undertaken in connection with or related to this Agreement, including without limitation any such damages which are based upon causes of action for breach of contract, tort (including negligence and misrepresentation), breach of warranty, strict liability, statute, operation of law, or any other theory of recovery. The provisions of this Section 19.2 will apply regardless of fault.

19.3 Delays in Interconnecting Customer's Facility

Notwithstanding anything to the contrary in this Agreement, MECL, or any of its successors, assigns, directors, officers, employees, representatives, agents and/or contractors or otherwise, will not be liable (whether based on contract, indemnification, warranty, tort, strict liability, or otherwise) to Customer for any claims, suits, judgments, demands, actions (including attorneys' fees), penalties, liabilities or damages whatsoever, including, without limitation, direct, incidental, indirect, consequential, punitive, and special damages, or loss of profits or revenues, as a result of a delay or failure to meet any schedule, except to the extent such delay or failure results from the gross negligence or reckless or willful misconduct of MECL or any of its successors, assigns, directors, officers, employees, representatives, agents and/or contractors or otherwise.

19.4 Exclusive Remedies

The remedies set forth in this Agreement are the exclusive remedies for the liabilities of each Party arising out of or in connection with this Agreement.

SECTION 20.0 – NOTICES

20.1 Emergency Numbers

Each Party will provide, by written notice, an emergency telephone number, staffed 24 hours-a-day, to call in case of an emergency.

20.2 Form of Notice

All notices, requests, claims, demands and other communications hereunder, unless otherwise specified in this Agreement, will be in writing and will be given (and will be deemed to have been duly given if so given) by hand delivery, cable, telecopy (confirmed in writing) or telex, e-mail, by mail (registered or certified, postage prepaid), or by overnight courier that provides evidence of delivery or refusal, to the respective Parties as follows:

If to MECL, to:

Maritime Electric Company, Limited
PO Box 1328, 180 Kent Street
Charlottetown, Prince Edward Island C1A 7N2 CANADA
Attention: (Vice President, Corporate Planning and Energy Supply)
e-mail: VPEnergy Supply@MaritimeElectric.com

With a copy to:

Maritime Electric Company, Limited
PO Box 1328, 180 Kent Street
Charlottetown, Prince Edward Island C1A 7N2 CANADA
Attention: (Manager, Production and Energy Supply)
e-mail: ManagerEnergySupply@MaritimeElectric.com

If to Customer to:
(INSERT CUSTOMER CONTACT INFORMATION)

or such other address as is furnished in writing by such Party in accordance with this Section 20.2; and any such notice or communication will be deemed to have been given as of the date received. Upon written request by Customer, MECL shall provide to Customer's designated Project Finance Holders any and all oral or written notices, demands or requests required or authorized by this Agreement to be given by MECL to Customer in the same manner provided by MECL to Customer.

SECTION 21.0 - HEADINGS

The descriptive headings of the Sections of this Agreement are inserted for convenience only and do not affect the meaning or interpretation of this Agreement.

SECTION 22.0 – WAIVER

Except as otherwise provided in this Agreement, any failure of either Party to comply with any obligation, covenant, agreement, or condition herein may be waived by the Party entitled to the benefits thereof only by a written instrument signed by the Party granting such waiver, but such waiver or failure to insist upon strict compliance with such obligation, covenant, agreement, or condition will not operate as a waiver of, or estoppel with respect to, any subsequent or other failure.

SECTION 23.0 - COUNTERPARTS

This Agreement may be executed in two or more counterparts, all of which will be considered one and the same Agreement and each of which will be deemed an original.

SECTION 24.0 - GOVERNING LAW

24.1 Applicable Law

This Agreement and all rights, obligations, and performances of the Parties hereunder, are subject to all applicable federal and provincial laws, and to all duly promulgated orders and other duly authorized action of governmental authority having jurisdiction.

24.2 Choice of Law

This Agreement will be governed by and construed in accordance with the laws of the Province of Prince Edward Island, Canada, without giving effect to the conflict of law principles thereof. Except for those matters covered in this Agreement and jurisdictional to IRAC or which must first go to arbitration pursuant to Section 13.0 herein, any action arising out of or concerning this Agreement must be brought in the courts of Prince Edward Island, Canada. Both Parties hereby consent to the jurisdiction of Prince Edward Island, Canada for the purpose of hearing before and determining any action by IRAC.

SECTION 25.0 - SEVERABILITY

In the event that any of the provisions of this Agreement are held to be unenforceable or invalid by any court of competent jurisdiction, the Parties will, to the extent possible, negotiate an equitable adjustment to the provisions of this Agreement, with a view toward effecting the purpose of this Agreement, and the validity and enforceability of the remaining provisions hereof will not be affected thereby.

SECTION 26.0 - AMENDMENTS

26.1 MECL Amendment Rights

Notwithstanding any provision of this Agreement to the contrary, MECL may unilaterally make application to IRAC for a change in any rates, terms and conditions, charges, classification of service. However, as set forth in Schedule I, MECL may unilaterally change the charges (as described in Schedule I), without application to or approval of IRAC, and the changed IFSC-NCR and/or IFSC-CR, as determined by MECL, will become effective on the date specified by MECL in its written notice to Customer, pursuant to Section 20.

26.2 Customer Amendment Rights

Notwithstanding any provision of this Agreement to the contrary, Customer may exercise its rights under the Electric Power Act and the Renewable Energy Act with respect to any rate, term, condition, charge, classification of service, rule or regulation for any services provided under this Agreement over which IRAC has jurisdiction.

26.3 Revision of Schedules

Notwithstanding any provision of this Agreement to the contrary, and without limiting or waiving any of MECL's other rights, MECL reserves the right to modify, in a manner not inconsistent with Good Utility Practice or IRAC policy, those provisions of the Schedules attached to this Agreement which are set forth below within parenthesis:

Schedule A (entire schedule)

Schedule B (additions or revisions to technical requirements by NERC or NPCC)

Schedule C (entire schedule)

Schedule D (only for (i) finalization of estimates, as set forth in the schedule; (ii) equipment identification; and (iii) annual updates to the inputs to the formula in accordance with the MECL's Tariff

Schedule G (costs of studies)

Schedule H (generator capability curve to be provided by Customer)

Schedule I (only for (i) finalization of estimates, as set forth in the schedule; and (ii) annual updates to the inputs to the formula in accordance with MECL's OATT Schedule I, as described in Section 27.1 above).

Schedule J (technical information to be provided by Customer)

The modified schedules will be incorporated by reference as if fully set forth herein, and will become effective on the date specified by MECL in its written notice to Customer, pursuant Section 20.

26.4 Amendment by Mutual Agreement

Except as provided for in Sections 26.1, 26.2 and 26.3, this Agreement may only be amended, modified, or supplemented by written agreement signed by both MECL and Customer.

SECTION 27.0 - ENTIRE AGREEMENT

27.1 Entire Agreement

This Agreement constitutes the entire understanding between the Parties, and supersedes any and all previous understandings, oral or written, which pertain to the subject matter contained herein or therein.

27.2 No Third Party Rights

Nothing in this Agreement, express or implied, is intended for the benefit of third parties and no third party may claim for damages or otherwise to enforce any such benefit.

SECTION 28.0 - OTHER CONDITIONS

28.1 Conflict with Other Documents

The MECL Tariff is supplemented by this Agreement to the extent permitted by law. This Agreement incorporates by reference the terms of the MECL's Open Transmission Tariff. The MECL Tariff may be modified from time to time in accordance with law and thereby affect the services furnished to Customer; provided, however, MECL shall not change the specific rates, terms or conditions set forth in this Agreement without making any necessary filings with IRAC to so amend the Agreement.

IN WITNESS WHEREOF the Parties have executed and delivered this Agreement as of the date and year first above written.

MARITIME ELECTRIC COMPANY, LIMITED

By: ______________________________ Name:

By: ______________________________ Name:

(Customer Name)

By: ______________________________ Name:

By: ______________________________ Name:

SCHEDULES

Description

SCHEDULE A

INTERCONNECTION FACILITIES AND ASSOCIATED EQUIPMENT

I. Customer:
Project:
Unit Location:
Net Capacity:
Point(s) of Interconnection:
Point(s) of Receipt:

II. Customer-Owned Interconnection Facilities and Associated Equipment (Description and Estimated Cost):

III. Direct Assignment Facilities (Description and Estimated Cost):

IV. Other Direct Assignment Facilities (Description and Estimated Cost):

SCHEDULE B
GENERATOR TECHNICAL REQUIREMENTS

I. **Purpose** - The purpose of this document is to establish the Technical Requirements for generation facilities to connect to the Maritime Electric Company, Limited's (MECL) Transmission System. This document reflects, in part, the MECL view of Good Utility Practice with respect to the installation of generation interconnection equipment. These requirements are written to establish a basis for maintaining power quality and a safe environment for the general public, power consumers, maintenance personnel, and equipment. This document describes the general protection requirements for parallel operation and includes typical one-line diagrams. This document also includes equipment maintenance requirements and details the information that must be provided to MECL during all stages of a project. This document is a guide and as such, is not intended to be used as the sole basis for the specific design of the generator's protection systems and interconnection with the Transmission System. Final design will be subject to review and approval on a case-by-case basis.

II. **Customer** - This term refers to the owner/operator of the generation facilities.

III. **Facility –** This term refers to generation facility.

IV. **Use** - This document is intended for general use by present Customers, prospective Customers and MECL personnel.

V. **Transmission System** - This term refers to the MECL electrical system that includes 138 and 69 kV transmission elements.

VI. **Qualified MECL Personnel** - This term is used to refer to those persons employed by MECL having the required knowledge, training, experience, and accountability in specialized areas of Transmission Services, Transmission Engineering, Operations and Planning.

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GENERATION INTERCONNECTION AGREEMENT

SCHEDULE B

TABLE OF FIGURES

1. GENERAL INFORMATION

The information in this generator technical requirements document is supplied to Customers for the purpose of establishing and maintaining an acceptable interconnection with the Transmission System. Safety and power quality are of utmost importance and, as such, careful study of each proposed installation and the identification of appropriate protective devices is required before a Facility is allowed to begin interconnected operation. This standard is based on MECL requirements as well as the regulations of authorities having jurisdiction over MECL.

A. MECL Review and Approval

MECL will review Transmission System parameters in relation to the proposed point of interconnection to determine any necessary changes to the Transmission System in order to accept the generation. MECL will verify that the Facility's design meets these interconnection requirements and will conduct a functional test of the Facility’s system before the Facility will be allowed to commence interconnected operation. MECL will provide the Customer written approval for interconnected operation with the Transmission System. Subsections 1 through 5, below, summarize this process.

1. Engineering Studies

Upon receiving a completed Generator Interconnection Request as per Schedule J, MECL will determine the requirements for a System Impact Study. The process for these studies is described in Section 19 and 32 of MECL’s OATT.

2. Interconnection Costs

Unless otherwise specified in a site-specific interconnection agreement, or any applicable transmission tariff, the Customer will pay the interconnection costs for any equipment required by MECL to allow connection to the Transmission System. This will include the costs of new transmission or transmission facilities and/or upgrades to existing facilities, metering equipment, and changes to the MECL Protection System. MECL will require prepayment for any necessary work.

With regard to any interconnection costs or ongoing charges, if there are any conflicts between these interconnection requirements and a site-specific interconnection agreement, or any applicable transmission tariff, as may be amended from time to time, the interconnection agreement or applicable transmission tariff will control.

3. Design Approval

MECL will review and provide written approval for the portion of the facility's design that is required to meet these interconnection requirements. This review and approval will only cover the required interconnection equipment and is not intended to provide overall facility design review.

4. Initial Inspection and Testing

Prior to the initial synchronization to the Transmission System, the interconnection equipment must be inspected, calibrated, and functionally tested. MECL will inspect the interconnection equipment and will either perform or observe the functional testing. Refer to Sections III.L, "Generator Facility Acceptance," and III.M, "Synchronizing to the Transmission System," for more specific information on this process.

5. Ongoing Testing and Maintenance

After the initial synchronization, the Customer is required to perform periodic testing and maintenance of the interconnection equipment to ensure this equipment will operate properly. Section VIII.E, "Testing & Maintenance," provides additional details for these ongoing requirements.

B. Grandfathering

Generators already connected to the Transmission System are not exempt from the requirements of this document. The MECL Interconnection Requirements are periodically revised to reflect changes in standard electrical practice and the Transmission System. Each Facility will be subject to review as a result of analyzing local Transmission System problems as well as during the initial inspection and ongoing biennial test and inspections. MECL may require reasonable modifications to the Interconnection Protection System as a result of these reviews and inspections.

C. Generators 1,000 kW and Larger and Facilities 1,000 kW and Larger

All individual generators with a minimum generating capacity of 1,000 kW and all Facilities that interconnect with the Transmission System with a minimum capacity of 1,000 kW must meet the review and approval criteria identified in Sections A and B, above. They must also be equipped with SCADA equipment as described in Section V, "Supervisory Control and Data Acquisition." For staffed Facilities, a telephone line dedicated to voice communications with the System Operator must be provided. For unstaffed Facilities, the Customer must provide an alternative means of communications to meet the requirements of the Systems Operator.

D. NERC, NPCC Requirements

Generation facilities that are connected to the Transmission System must also comply with North American Electric Reliability Council (NERC), and Northeast Power Coordinating Council (NPCC) criteria, guides, requirements, and standards.

E. DC and Variable Speed Generators

Direct current generators and variable speed alternating current generators may be connected to the Transmission System through a synchronous inverter. The inverter installation will be designed such that a Transmission System interruption will result in the removal of the generator/inverter from the Transmission System. Synchronous inverters must comply with MECL power quality requirements as outlined in Section VI, "Power Quality".

F. Generators Less than 1,000 kW

Generation equipment less than 1,000 kVA and greater than 100 kW may be installed, where appropriate Transmission lines exist, without an extensive engineering review. The level of detail of information required depends on the site at which the interconnection occurs. In all cases, the Customer must install the appropriate protection and obtain written approval from MECL, as specified in this document, before commencing interconnected operation. For facilities 100 kW or smaller, MECL approval must still be obtained, though the level of detail is less than that required for facilities greater than 100 kW.

G. Emergency Generators

Emergency generators cannot be connected to, or operated in parallel with, the Transmission System, except for momentary paralleling (paralleling for 0.5 seconds or less). Facilities may utilize momentary paralleling of emergency generators providing they use automatic controls to monitor and control the switching process. The automatic control and switching system will require MECL review and approval. These facilities do not require a protection system to monitor for faults on the Transmission System.

II. GENERAL REQUIREMENTS

The Customer's installation shall meet all requirements of Good Utility Practice, methods, and standards that are commonly used in engineering and plant operations and maintenance to provide for a safe and dependable installation.

In addition to meeting those practices, methods, and standards and the requirements set forth in this document, as may be changed from time to time, the Customer's equipment and installation shall conform to the latest revision of all applicable Federal, Provincial, and Local Government codes. These include without limitation, the Canadian Standards Association (CSA), Electrical Equipment Manufacturers Association of Canada (EEMAC), American National Standards Institute (ANSI), Institute of Electrical and Electronics Engineers (IEEE), National Electrical Manufacturers Association (NEMA), Underwriter's Laboratory (UL), Underwriter's Laboratory of Canada (ULC), Occupational Health and Safety Act of Prince Edward Island (OHSA), Canadian Environmental Assessment Act (CEAA), Prince Edward Island Department of Environment, Energy and Forestry, Municipal Planning Commissions and Boards, North American Electric Reliability Council (NERC), Northeast Power Coordinating Council (NPCC), and Maritime Electric Company, Limited standards.

A. Interconnection Process and Required Information

To facilitate the interconnection process, the Customer should contact MECL early on in the design stages of the proposed installation. The Customer must provide MECL the following information on each proposed facility:

- Complete, accurate, and applicable data to enable the proper modeling of the Customer's unit(s) in load flow, transient stability, and fault studies. This will include line, transformer, and machine data as well as parameters for exciter systems, governor systems, and power system stabilizers.
- Design data and specifications that reflect the facility’s reactive capability.
- All information regarding design and implementation of any Special Protection System(s) associated with its facilities.
- Unit availability data including both unit design data and known performance data from other facilities utilizing similar equipment.

The Generator Interconnection Request Form, Schedule J, provides Electrical Equipment Data Sheets that the Customer must complete and forward to MECL to allow an engineering study to be performed. Upon receipt of the required information, as part of the engineering study, MECL will review the Interconnection Protection System requirements. Any additional requirements not explicitly specified in this document will be provided by MECL to the Customer. The Customer must submit design documents reflecting these additional requirements to MECL for review and approval.

B. Protection System Requirements

Each Customer must design, install, maintain, and operate appropriate protection systems. The Customer must obtain MECL approval of specific relays and interconnection equipment before parallel operation can begin. Section III, “System Protection,” covers MECL requirements for the protection systems in greater detail.

C. Transformer Interface

In general, the Customer's facility shall interface with the Transmission System through a step-up transformer or bank of transformers of adequate kVA rating and proper voltage rating for conversion from the facility's generator voltage to transmission voltage. MECL requires that the transformer have a y-connected solidly grounded high voltage winding. The low voltage winding must be delta-connected or there must be a delta-connected tertiary winding. MECL also requires that the step-up transformer voltage drop during in-rush be less than 3% after 2 cycles. The ratio of this step-up transformer must not restrict the reactive capability requirement specified in Section F, "Reactive Capability," below.

D. Switching Equipment and Station Ground

Each installation must be provided with the following switching equipment and station ground:

1. Tie Disconnect Switch

The Customer will provide a manual, three-phase, gang-operated, visible, lockable, interrupter (tie disconnect) switch at the point of connection to the Transmission System. See Section VII, "Safety," for switch operation requirements. Facilities with generation capacity of 100 kW or less will be subject to MECL's Net Metering procedures.

2. High-Side Interrupting Device

The high side of the facility's step-up transformer must be connected to the Transmission System through a high-side circuit breaker, recloser, or fuse. This device must be capable of interrupting both the facility's full generation capacity and the maximum fault current at this location.

3. Station Ground

The facility's station ground must be designed and installed in accordance with MECL requirements and CSA Standards.

E. Generator Circuit Breakers

A circuit breaker is normally required between each generator and the generator step-up transformer. This breaker provides a means to disconnect the generator from the Transmission System under fault conditions as well as providing a means to synchronize to the Transmission System. Under certain conditions, it may be more economical to design this device into the high-voltage side of the step-up transformer. If this is the case, a low-side disconnect device will still be required.

F. Reactive Capability

All synchronous generators shall be rated to operate continuously at maximum rated power and at any power factor between 90 percent lagging and 95 percent leading within ±5 percent of rated voltage. The generator step-up transformer ratio will be set such that the generator will support this reactive capability. Generators may be required to operate in either reactive power or voltage control modes as directed by the System Operator to assist in maintaining proper system voltage. Generators must maintain operating limits or interconnection service will be discontinued.

Asynchronous generators will normally produce reactive power flows that will hold the voltage at the delivery point constant at a pre-determined value with the capacity to operate at power factors in the range of ±0.98 while producing full real power output and with the voltage of the delivery point constant at 1.0 per unit.

The nominal rating of the step-up transformer's high voltage winding will be specified by MECL to ensure the Transmission System reactive power requirements are met. As a minimum, the step-up transformer will be provided with tap settings that span ±5 percent of the nominal voltage at 2½ percent intervals.

Taps on any station service transformers within the Facility will also be set such that the Facility will support this reactive capability requirement. If tap settings restrict the generator's reactive capability, the transformers must be replaced. The cost for such replacement will be the responsibility of the Customer.

G. Routine Maintenance

As a minimum requirement, each Customer is expected to adopt an Operations and Maintenance program consistent with the Operations and Maintenance section of this document. Maintenance records will be kept on file at the Customer's facility and will be provided to MECL upon request.

H. Capacitors

Excitation or power factor correction capacitors may be installed on generators only with the written consent of MECL.

I. Phase Unbalance

There may be single-phase fuses or automatic line switching devices, installed between the utility power source and the generator, which may operate and cause phase unbalance. It is the sole responsibility of the Customer to protect its own equipment from any such unbalance. MECL will not assume any responsibility or liability for this protection.

J. Changes

Changes to the interconnection, including protective relaying and metering, as well as changes to special operating conditions caused by the Customer's equipment could affect the safety, reliability, and performance of the Transmission System. Therefore, all such changes must be submitted in writing to MECL a minimum of thirty (30) days prior to making any such change. These changes will require written approval by MECL. These changes include, but are not limited to, the following:

1. Changes to the Transmission System

MECL may find it necessary to perform changes to the Transmission System serving the Customer's interconnected facility. In turn, such changes could affect the Customer's facility, resulting in required changes there also.

2. Changes to the Interconnection Protection System

No modifications will be performed on the interconnection relays, their specified set points, or other associated equipment by the Customer or the Customer's representative without written approval from MECL.

3. Changes to Transformers

No changes to the generator's step-up transformer ratio are allowed without written approval from MECL.

4. Changes to the MECL Protection System

If any changes are required to the MECL Protection System due to the Facility's interconnection, those changes will be performed by MECL at the Customer's expense.

5. Unauthorized Changes

Changes to the interconnection equipment without MECL written permission will result in the facility interconnection service being discontinued until the facility returns to compliance with these requirements.

K. MECL Disclaimer

An MECL review of the Customer's facility, equipment, interconnection equipment, protective devices, and metering does not confirm or endorse the design. An MECL review is not a warranty of safety, durability or reliability of the facility or any of the equipment. MECL shall not, by reason of such review or failure to review, be responsible for strength, safety, details of design, adequacy or capacity of the Customer's facility, equipment, interconnection equipment, or protection systems. MECL will not assume any responsibility or liability for protection of the Customer's electrical system resulting from interconnected operation of a Customer's facility with the Transmission System.

III. PROTECTION SYSTEMS

Requirements for protection due to interconnected operation of generation facilities will vary depending on the size and type of installation and the characteristics of the Transmission System at the point of interconnection. The following requirements are necessary for planning and designing generation facilities for interconnected operation with the Transmission System.

A. MECL Engineering Review of Proposed Generation Facilities

Only those portions of the drawings and other design documents which apply to the Interconnection Equipment and the Interconnection Protection System will be reviewed to determine if any changes are required due to the interconnected operation of the Customer's facility.

B. Transformer Connections

The step-up transformer high voltage winding must be connected in a wye configuration and solidly grounded. The low voltage winding must be delta-connected or there must be a delta-connected tertiary winding. The Customer will coordinate with MECL to select a transformer connection and grounding arrangement.

C. General Protection System Descriptions

The MECL Protection System and the Interconnection Protection System must provide the necessary level of protection for the Transmission System. MECL will determine the Interconnection Protection System relay settings and changes to the existing MECL Protection System or other power system equipment due to the interconnected operation of the Customer's facility.

1. Interconnection Protection System

The Interconnection Protection System must detect power system faults or abnormal conditions and will not take into consideration protection for the Customer's electrical system or equipment; rather it will provide protection for the Transmission System and other customers. The Interconnection Protection System will:

- comply with the minimum operating and safety standards set forth in these requirements;

- operate to limit the severity and extent of system disturbances and damage to Transmission System equipment;
- detect abnormal operating conditions and disconnect the Customer's facility when such conditions do not return to normal within certain time limits;
- communicate with utility equipment as required;
- monitor for loss of the utility supply (feed) and prevent energizing a de-energized utility circuit, except when doing so as provided under Section VI.D, "Islanded Generation Limits;" and
- be located in a secure, environmentally controlled, easily maintained, and readily accessible location, such as a switchgear room.

2. NPCC Requirements

Any Customer whose facility is interconnected to the Transmission System will be required to meet Northeast Power Coordinating Council (NPCC) guidelines for protection requirements. These guidelines may require redundant protection equipment including station batteries, breaker trip coils, station service AC supply, and breaker failure systems. MECL will verify these requirements are incorporated into the interconnected facilities.

3. Generator Protection System

Customers must provide the necessary Generator Protection System to protect their own equipment. MECL will provide system data to the Customer to allow the Customer to coordinate their protective system settings with the MECL Protection System and the Interconnection Protection System and may include provision for tripping the generator offline by special telecommunications signals.

In addition to these standard protection systems, MECL may require other Special Protection Systems at certain sites. Special Protection System requirements will be determined by MECL on a case-by-case basis. The Generator will not be compensated by MECL for costs incurred by the Generator due to a Special Protection System trip unless the Transmission Provider is negligent.

D. Quality of Protection System Equipment

Protection system components must perform under extreme environmental and electrical transient conditions. Therefore, equipment ratings must meet or exceed American National Standards Institute (ANSI) and Institute of Electrical and Electronic Engineers (IEEE) Standards (i.e. all protective relays must meet or exceed ANSI/IEEE Standard C37.90). In addition, protection systems must include design, maintenance, and testing features as follows:

1. Equipment Quality

The Interconnection Protection System equipment, including auxiliary equipment and instrument transformers, must be utility grade (of suitable quality, proven design and commonly used in similar applications).

2. Primary Wiring

All primary or high-voltage wiring of CTs, PTs, circuit breakers, etc., shall be in accordance with CSA standards, provincial regulations, MECL standards and based on Good Utility Practice.

3. Secondary Wiring

All secondary wiring and connections on the Interconnection Protection System and its associated equipment shall meet all national and provincial requirements and based on Good Utility Practice.

All interconnection relay trip outputs must be hard-wired directly to the tie breaker or interposing lock-out device. No interconnection relay trip may be wired through, or derived from, any interposing device, such as a programmable logic controller (PLC) or a plant process computer.

Screws, studs, nuts, and terminals used for Interconnection Protection System electrical connections shall be nickel plated brass/copper alloy. The wire used will be no smaller than #14 AWG stranded copper, except wire used for grounding of CT and PT circuits will be no smaller than #12 AWG. All wire insulation will be cross-linked polyethylene or equivalent high quality insulation (type "SIS" or equivalent). Polyvinyl chloride insulation is not permitted. The minimum rating for insulation is 600 volts. Wire terminations must utilize solderless, "Crimp-Style" ring lug terminals. "Spade" or "Fork" type lug terminals are not permitted.

4. CT Ratio/Accuracy

All CT ratios and accuracy classes shall be chosen such that, under maximum fault conditions, secondary current is less than 100 Amperes and transformation errors are less than 10%.

E. Primary Interrupting Device

The Customer’s facility must be connected to the Transmission System through a primary interrupting device. This device must be capable of interrupting the maximum fault current available at the facility. If this device is a breaker, it must be capable of opening after loss of either the facility’s generation, the Transmission System, or both. In addition, this breaker must have the ability to be electrically tripped (opened) by the Interconnection Protection System. If this device is a fuse it must be sized in consideration of the facility’s kVA rating and the maximum available fault current at the facility.

In certain installations, high-side fault protection may be provided by MECL remote-end line protection. In these specific installations, a high side fault interrupting device may not be initially required providing no other MECL customers are affected by remote-end tripping. However, future changes to the Transmission System may require the Customer to install a high-side fault protection device at a later date. Under these circumstances, if MECL determines that high-side fault protection is necessary, the Customer will be responsible for the cost of installing the necessary equipment.

F. Trip Source (Battery)

The source of tripping and/or control power must be a storage battery, equipped with a battery charger, and designed and suitable for the intended use. This trip source will be ungrounded and equipped with a ground detection system.

The battery must have sufficient capacity, in accordance with appropriate IEEE Standards, to permit operation of the station in the event of a loss of the battery charger or AC supply. The battery charger must be capable of supplying the station load plus charging the battery and shall be equipped with over/undervoltage alarms for monitoring the battery voltage and battery charger supply.

All DC peripheral devices must be fused separately from the protection systems, including the breaker trip coil(s). This will prevent the failure of any other device from jeopardizing the security of the protection systems. Use of AC voltage, or use of the generator exciter as a source of DC power, is not an acceptable alternative to the battery and charger system. The battery and breaker trip coil must be a nominal 48 volts DC, minimum. The breaker trip coils and relay circuits must be monitored for loss of DC.

G. Islanding

Islanding is the operation of the Customer's facility supplying an isolated portion of the Transmission System. This operation can create hazards to personnel, other customers, and the general public, and may cause equipment damage. Because of the hazards involved, islanding must be avoided, except as provided for in Section VI.D, “Islanded Generation Limits”. Where it is allowed, the Customer’s facility shall be designed with appropriate control and protection systems to safely supply connected loads while islanding.

In situations where islanding is not allowed and the Customer's facility is not immediately disconnected from the Transmission System after the utility breaker opens, additional relaying and/or communications equipment will be required, at the Customer’s expense. See Section I, "Transfer Trip” below.

H. Automatic Reclosing

MECL utilizes automatic reclosing to reduce outage durations of the Transmission System. Should a utility circuit breaker open due to a detected fault condition, that circuit breaker will automatically reclose. The Customer's equipment, the Transmission System, and other MECL customers' equipment is susceptible to damage if the circuit breaker closes back in while the generator is still connected to the Transmission System. Additional fault interrupting devices may exist between the utility substation breaker and the Customer's facility. Customers are responsible for protecting their equipment from automatic or manual reclosing of all such utility devices.

I. Transfer Trip

MECL may require, or the Customer may request, that MECL install transfer trip equipment as additional protection against the Customer's facility backfeeding a portion of the Transmission System. This equipment shall provide separation of the Customer's facility from the Transmission System in the event of system disturbances detected by utility equipment remote from the Customer's facility. The Customer will be responsible for all costs associated with the installation, operation, and maintenance of such equipment, including the installation and ongoing costs associated with any required communications channels.

The Customer may be required to provide local breaker failure protection, which may include direct transfer tripping to the utility line terminal(s), in order to detect and clear faults within the Customer’s facility that cannot be detected by MECL back-up protection.

J. MECL Underfrequency Load Shedding Program

The Underfrequency Load Shedding (UFLS) program is designed to match load to generation for the loss of a major tie line or the significant loss of generation, and to return the system frequency to acceptable limits following such a loss. MECL must review and report annually to the Northeast Power Coordinating Council (NPCC) on this program. Frequency relaying installed as part of the Interconnection Protection System and the Generator Protection System will be set according to criteria which will allow MECL to meet UFLS program goals.

Each Customer is responsible to review the setting criteria to ensure that the MECL specified settings will not unduly stress their generating equipment. In instances where these settings cannot be implemented in accordance with these criteria, or where generator controls or auxiliary equipment prevent generator operation at these frequencies, MECL will install alternate load relief to compensate for the lost generation. The Customer will be responsible for the cost of providing and maintaining this alternate load relief.

Customers who have other frequency and/or speed control devices not required by MECL must coordinate the setpoints of these devices with the interconnection frequency relay settings specified by MECL. If there is no interconnection frequency relay, these other devices must be set to meet the UFLS program. The Customer will be responsible to test any of these additional devices and maintain this test information on file. Such information will be provided to MECL upon request.

K. Blackstart Capability

In order to meet the requirements of NPCC, certain generators interconnected to the Transmission System may have blackstart capability. These generators must be able to start without an external power source, to allow for restoration of the Transmission System in the event of a system-wide outage. This capability must be tested every year, unless conducting such a test would interrupt firm customer load. In this instance, the testing interval will be as agreed to by the Customer and MECL, on a case-by-case basis.

L. Generator Facility Acceptance

Before interconnected operation with the Transmission System can begin, the Customer’s facility must be inspected by MECL to verify that protection system requirements are met, that operability of Interconnection Protection System is verified, and that all appropriate testing has been completed. To facilitate this process, the Customer will assign an engineer or technician who is currently registered or licensed in the province of Prince Edward Island. This person will coordinate the start-up testing and operation of all equipment and act as the liaison between the Customer and MECL until the interconnection requirements have been met.

Two weeks prior to the initial functional test, the Customer shall supply as-built protection drawings to MECL. These drawings must provide sufficient information for MECL to analyze all functional test requirements specified below.

- CTs: rating, circuit polarity, ratio, insulation, excitation, continuity and burden tests.
- PTs: rating, circuit polarity, ratio, insulation and continuity tests.
- Relay pick-up and time delay tests.
- Functional breaker trip tests from protective relays.
- Relay in-service tests to check for proper phase rotation and magnitudes of applied currents and voltages.
- Breaker closing interlock tests.
- Paralleling and de-paralleling operation.
- Other relay commissioning tests typically performed for the relays involved.

Such tests are required to demonstrate:

- The correct functioning of governors, exciters and synchronizer circuits for each unit.
- The reactive capability of each unit.
- That the actual exciter gain matches the gain documented in the exciter model.
- That the governor droop is set to 4%.
- That the unit matches the open circuit saturation curve data calculated by the manufacturer, and
- That the unit matches the short circuit saturation curve data provided by the manufacturer.

The Customer will provide MECL a copy of all test data for evaluation. MECL will perform or observe a functional test and commissioning of the entire Interconnection Protection System. This will include a calibration check of the interconnection protective relays and as many trips of the interconnection breaker and/or the generator breaker(s) as MECL considers necessary to verify the correct operation of the Interconnection Protection System and the breaker trip circuits. Phase rotation and synchronizing will also be verified.

To facilitate this testing, test points must be accessible to permit injection of test voltages or currents to verify the calibration and operation of the components making up the Interconnection Protection System. One means of providing these test points is incorporating ABB FT or GE PK test blocks into the facility design. These test points shall also interrupt the protection system trip outputs. MECL will review and approve the testability of the Interconnection Protection System as part of the initial design review.

After the final commissioning, the Customer must provide MECL with one set of accurate drawings and maintain one set on-site. Any subsequent changes to the facility impacting the Interconnection Protection System must be approved by MECL before being incorporated. After incorporation, such changes must be verified by MECL and documented and incorporated into the facility prints within ninety (90) days. A set of updated prints will be provided to MECL within this time-frame.

M. Synchronizing to the Transmission System

All components of the Interconnection Protection System, the Generator Protection System, and the synchronizing circuits must be energized and functioning correctly before the Customer will be allowed to begin parallel operation with the Transmission System.

The Customer is solely responsible for properly synchronizing to the Transmission System. No more than a 3% instantaneous variation in voltage (flicker) is allowed when connecting or disconnecting any generator or station load to the Transmission System. The circuit breakers associated with the generating units must be equipped with facilities to automatically or manually synchronize the generating unit with the Transmission System. All synchronizing must be performed with the aid of either a synchronizing relay or a synchroscope. A sync check relay is recommended to prevent catastrophic errors during the synchronizing process.

NOTE: For facilities 1 MVA or greater, the Customer must notify the System Operator prior to connecting or disconnecting any generation or station load on the Transmission System when such action is a planned operation.

MECL requires a detailed procedure from the Customer for the initial synchronization. The Customer's actual synchronizing procedure will require approval from MECL. See Figure I for a sample procedure. Upon complete implementation of the Customer's procedure, assuming that all technical requirements have been met, the Facility will be allowed to connect to the Transmission System and begin parallel operation.

NOTE: The System Operator must be notified at least 24 hours prior to the initial synchronizing. **THE INITIAL SYNCHRONIZATION SHALL BE WITNESSED BY MECL.**

N. Typical Installations

The installations listed in this section provide the important characteristics of connecting to a transmission line. Transmission line and substation busses generally have two (or more) connections with the rest of the Transmission System, and are typically of higher voltage. The nominal phase-to-phase transmission voltages within the Transmission System are 69 and 138 kV.

The following subsections give a general overview of acceptable interconnection designs. Figures II and III are one-line diagrams for the installations listed below. Figure IV provides a legend of symbols used in the one-line diagrams. ALL INSTALLATIONS MUST BE REVIEWED AND APPROVED BY MECL PRIOR TO FINAL ACCEPTANCE AND COMMISSIONING.

Transformer			
Type	**Rating**	**Configuration (HV-LV)**	**Utility Connections**
I	Any size 3-phase	Wye-Grounded Wye Grounded with a Delta-Tertiary	Transmission-Line
II	Any size 3-phase	Wye-Grounded Wye Grounded with a Delta-Tertiary	Transmission-Bus

Figure I:

Sample Synchronizing Procedure for Commissioning

Purpose:

To verify proper rotation and phase relationships of primary and secondary circuits of Customer’s generator and the Transmission System prior to connection.

Discussion:

Both the incoming and running PTs will be energized from a common source. Rotation and phase angle checks will be taken on both PTs and the synchronizing circuits will be verified for correct operation.

Precautions:

To prevent personnel injury and motoring the generator, the links between the generator and the main bus shall be removed prior to performing any switching.

The safety of the plant will be the Customer's responsibility.

Prerequisites:

- Verify that all relay and control testing has been completed and the unit step-up transformer and all other pertinent equipment is ready for energization.
- Verify that the 86 devices have been reset.
- Verify generator and transformer relays are operable.
- Verify transformer auxiliaries are ready to be energized and operable.
- Signature ____________________________________

Procedure:

a. Energize main step-up transformer from the Transmission System.

b. Read and record rotation on running PTs.

c. Read and record bus voltage on running PTs for all 3-phases. Phase A, _____ Phase B and Phase C __By: ___________________

d. Close generator breaker to energize incoming PTs.

e. Observe synchroscope is at 12 o'clock position. If not at 12 o'clock position, STOP and inform MECL. By: __________________________

f. Read and record rotation on incoming PTs. Should be the same as running PTs. If not, STOP and inform MECL. By: __________________________

g. Read and record bus voltage on incoming PTs for all 3-phases. Phase A ___________ Phase B ___________ Phase C ___________ By: ____________________

h. Should be the same as running PTs. If not, STOP and inform MECL. By: __________________________

i. Return system to normal.

j. Reinstall generator links.

k. Rack generator breaker into test position.

l. Bring unit up to rated speed and voltage.

m. Using a strip chart recorder, record voltage and speed matching capability.

n. Allow auto synchronizing equipment to close generator breaker in test position. Record phase angle difference between generator bus and the Transmission System at time of closing. Mismatch must be less than 1% between the incoming and running voltmeter. The phase difference must be zero. (This information required to be on file with MECL.)

NOTE: Check for Syn. Instructions for wind generator.

o. Open the generator breaker.

NOTE: If provisions have been made for manual synchronizing, the operator must demonstrate his ability as follows:

p. Select sync selector to "Manual".

q. Adjust unit speed allowing at least 6 seconds per revolution on the synchroscope (generator faster than the Transmission System).

r. Adjust voltage to less than 1% voltage mismatch.

s. At 6 seconds per revolution, the operator would initiate the close pulse approximately 5 degrees prior to the 12 o'clock position.

t. Record phase angle difference between generator bus and the Transmission System at time of closing.

u. Rack generator breaker into normal operating position and repeat synchronizing procedures n. through t. By: ______________________________. (This information required to be on file with MECL.)

Final <u>Conditions</u>:

- Synchronizing procedure has been completed.

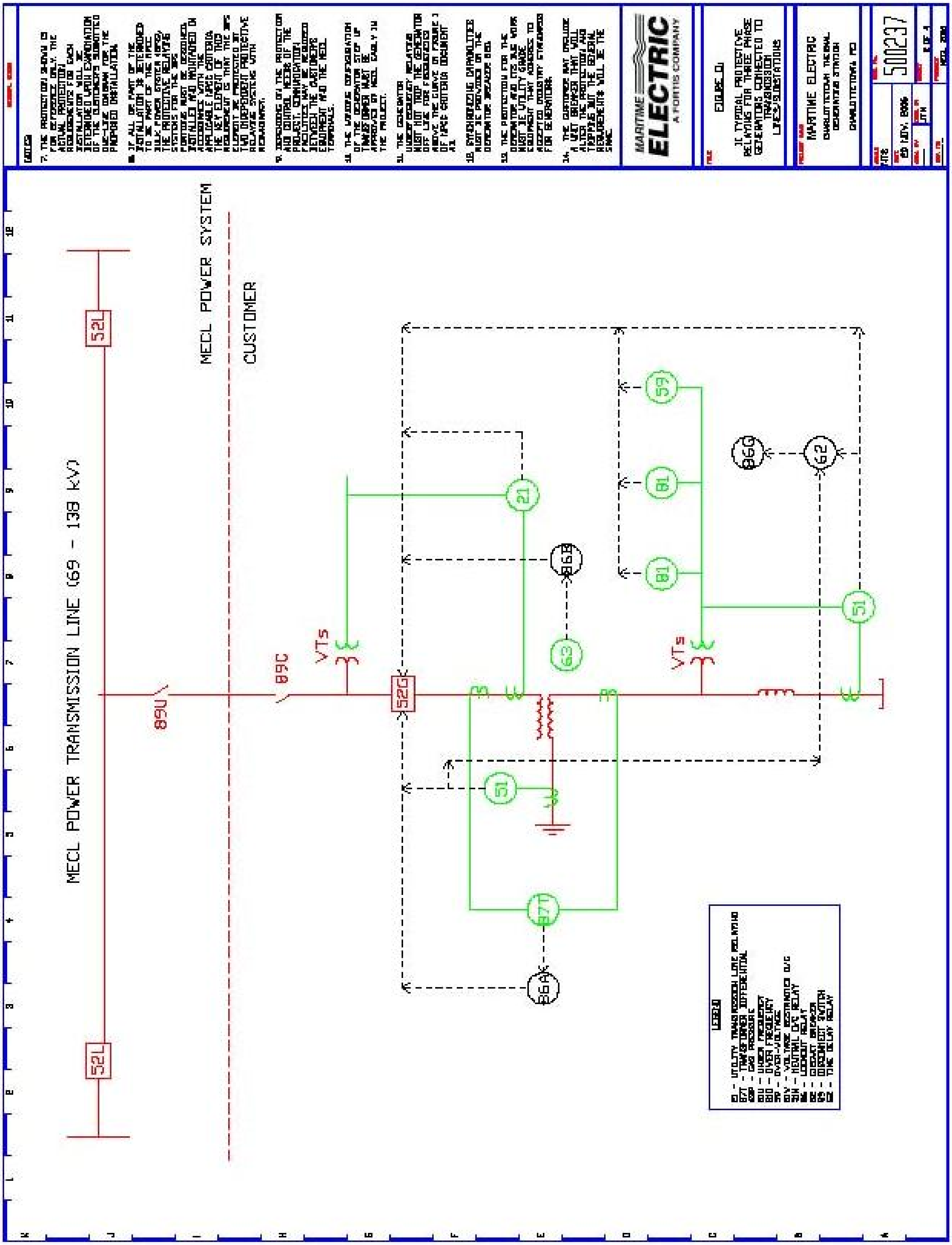
Date/Time: ______________________

Operator: ______________________

1. Type I Installations - (Figure II)

These are three-phase generators (synchronous or induction) interconnected to the Transmission System. This installation provides for power flow from the Customer's facility to the Transmission System as a normal operating mode.

- This installation requires primary circuit breakers or circuit switches designated as components "52L" in Figure II, which are capable of interrupting the maximum available fault current at this location.
- System Operations directly controls the operation of all switching devices on the utility Transmission System. On this type installation, the Facility's switches affected are the tie disconnect switch, the station grounding switch, and "52L".
- The Facility's control scheme must be designed to allow for the closing of breaker "52G" only if the feed from MECL is energized, or breaker "52L" is open. If breaker "52L" is open and breaker "52G" is closed, the generator may synchronize across breaker "52L". If the feed from MECL is not energized, then the Facility's control scheme must prevent closing of both breakers "52G" and "52L". Blackstart facilities will require an override to this control which will be utilized only under the direct authorization of System Operations.
- This installation requires telecommunications channel relaying and/or transfer trip for high speed fault clearing capability.
- PTs providing sensing input to Interconnection Protective Relays must be continuously rated for line-to-line voltage.
- MECL will require the Customer to provide two independent, redundant relaying systems where required by NPCC criteria. This will also be required for Facilities interconnected to the Transmission System if MECL determines that delayed clearing of faults within the Customer's Facility could adversely affect the Transmission System.


MECL POWER TRANSMISSION LINE (69 - 138 KV)
MECL POWER SYSTEM
CUSTOMER
52L
89U
89C
52G
VTs
21
86B
63
51
87T
86A
59
81
86G
62
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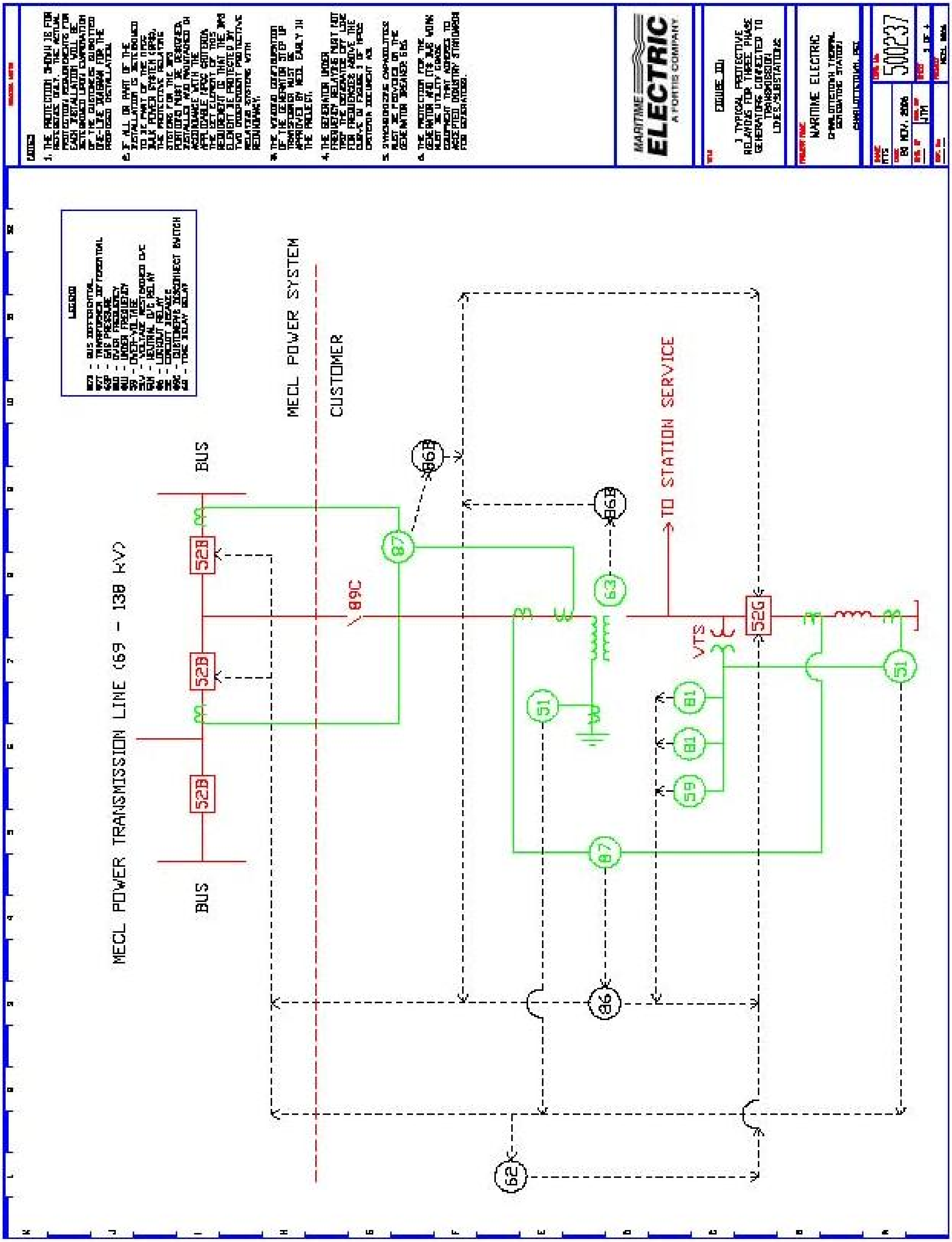
2. Type II Installations - (Figure III)

This installation is interconnected to the utility Transmission System through a substation bus at transmission voltages. The substation bus will be connected to at least two (2) utility transmission sections. This design provides for power flow from the customer's facility to the utility as a normal operating mode.

Because the facility is connected to a transmission bus, some of the standard connection relays for the other installation types are not required. Specifically, over/under frequency relaying is not required except to protect the generation itself where a generator will not island to serve local distribution load connected to the bus. As shown in Figure III, other relaying, such as bus differential relaying may be required to meet site-specific conditions.

- As with the Type I installation, a primary circuit breaker is required, rated to interrupt maximum available fault current, designated as "52B' in Figure III. This breaker, along with the associated breaker disconnects, bypass switch and grounding switch, will be under the direct control of System Operations.
- The Facility's control scheme must be designed to allow for the closing of breaker "52G" only if the feed from the Transmission Provider is energized or breaker "52B" is open. If breaker "52B" is open and breaker "52G" is closed, the generator may synchronize across breaker "52B". If the feed from Transmission Provider is not energized, then the Facility's control scheme must prevent closing of both breakers "52G" and "52B". Backstart facilities will require an override to this control which will be utilized only under the direct authorization of System Operations.
- Transmission Provider will require the customer to provide two independent redundant relaying systems where required by NPCC criteria. This will also be required for Facilities interconnected to the Transmission System if Transmission Provider determines that delayed clearing of faults within the Customer's Facility could adversely affect the Transmission System.


MECL POWER TRANSMISSION LINE (69 - 138 KV)
BUS
BUS
MECL POWER SYSTEM
CUSTOMER
TO STATION SERVICE
VTS
52B
52B
52B
52G
89C
87
87
86B
86B
86
63
51
51
81
81
59
62
MARITIME ELECTRIC
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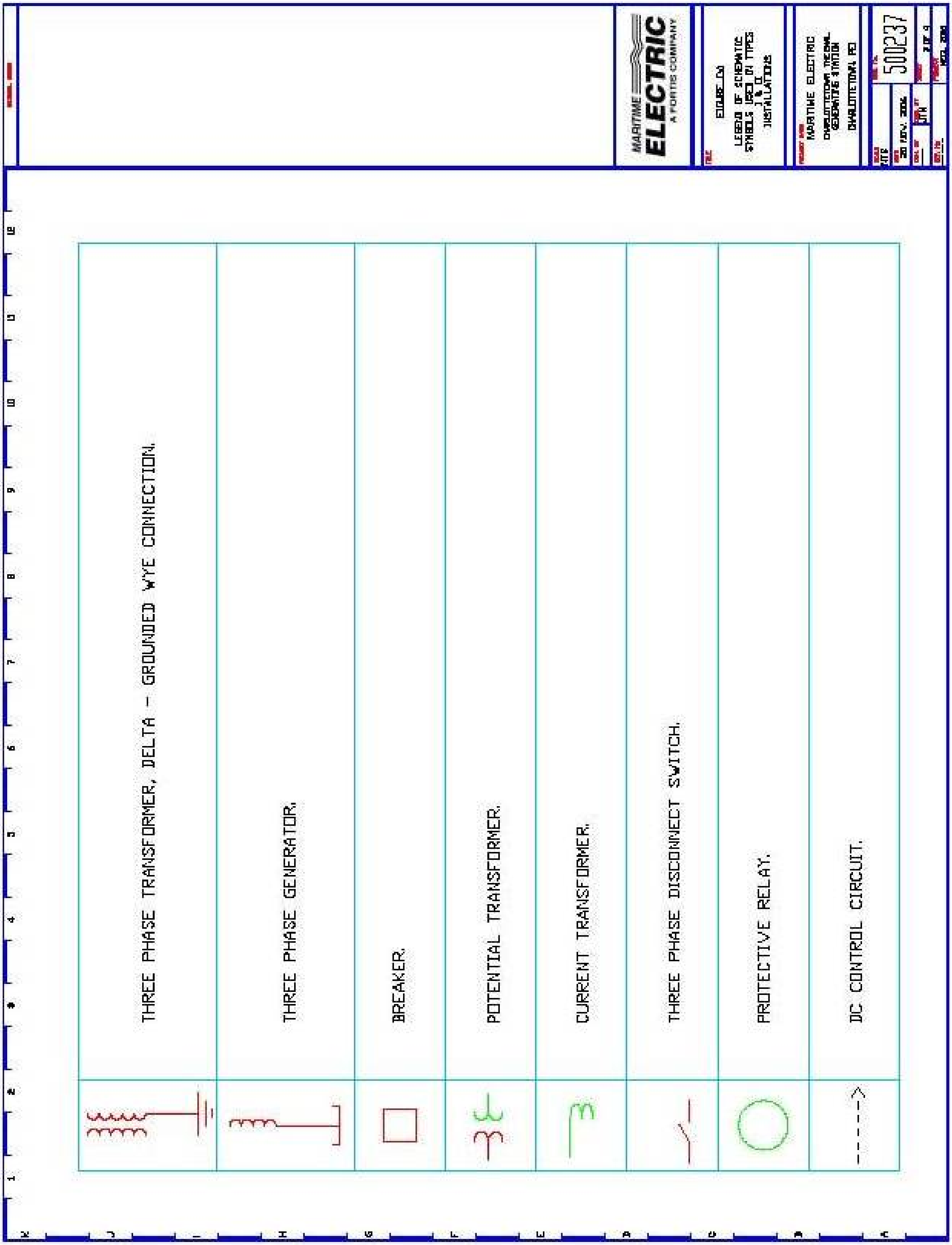
500237


THREE PHASE TRANSFORMER, DELTA - GROUNDED WYE CONNECTION.
THREE PHASE GENERATOR.
BREAKER.
POTENTIAL TRANSFORMER.
CURRENT TRANSFORMER.
THREE PHASE DISCONNECT SWITCH.
PROTECTIVE RELAY.
DC CONTROL CIRCUIT.
MARITIME ELECTRIC
A FORTIS COMPANY
LEGEND OF SCHEMATIC SYMBOLS USED IN TYPES I & II INSTALLATIONS
MARITIME ELECTRIC
CHARLOTTETOWN THERMAL GENERATING STATION
CHARLOTTETOWN, PEI
500237
20 NOV. 2006

O. Exceptions

While the majority of installations have been discussed, this document cannot cover every possible contingency or variation in equipment to be encountered at the various generator installations. Questions on the protective relaying to be used at any installation not covered by this document shall be addressed to MECL.

IV. METERING

Any location where a Facility is connected in parallel with the Transmission System will be metered to measure energy flow in two directions. The metering requirements contained herein assume bi-directional metering at the point of interconnection. Any other metering arrangement will require approval of, and design by, MECL.

A. Revenue Metering Location

The physical location of the revenue metering point is to be as close as practical to the actual contractual delivery point and must be approved by MECL.

Normally station service metering is accounted for within the generator metering using bi-directional metering; however, where the Station service is not accounted for within the generator metering, it shall be separately metered.

B. Loss Compensation

Where the metering point is not located at the contractual delivery point, the metering shall be adjusted to allow for the losses between the contractual metering point and the physical metering point.

C. Metering Ownership and Maintenance

MECL will own the Revenue Metering Equipment associated with the station service and the generator output to the MECL system.

MECL’s Revenue Metering equipment and installations will be approved, inspected, tested and maintained in keeping with MECL polices and Measurement Canada regulations.

A metering monthly operation and maintenance charge will be charged as per Schedule D of the Generation Interconnection Agreement (Revenue Metering Equipment and Costs).

D. Construction of New and Upgraded Metering Installations

1. The Customer will provide at its expense adequate space and facilities on its premises, satisfactory to MECL, for the installation and maintenance of the Revenue Metering Equipment. Facilities may include but not be limited to concrete foundations, conduit, and enclosures etc.

2. MECL will be responsible for the design, procurement, installation and commissioning of all Revenue Metering Equipment. The Customer will be required to pay MECL's full cost of the design, procurement, installation and commissioning of all Revenue Metering equipment.

3. The procurement and installation of instrument transformers may become the responsibility of the Customer where it is mutually agreed, by the Customer and MECL, and it is more economical to purchase the revenue metering instrument transformers installed within the Customer's equipment, such as switchgear. The location, type, accuracy class, and ratios of revenue metering instrument transformers purchased within the Facility's equipment must be approved by MECL. All instrument transformers must be approved by Measurement Canada for revenue metering. The Customer is responsible to supply factory certification tests and the Measurement Canada approval numbers for instrument transformers supplied within the Facility's equipment. The instruments transformers will be owned by MECL.

4. Where the Customer and MECL agree to install the revenue metering instrument transformers within the Facility's equipment, the Customer is responsible for all future costs associated with replacing the instrument transformers. Instrument transformers must be replaced when they fail or when they are not performing within their designed burden and accuracy ratings.

E. Use of Revenue Metering Instrument Transformers

Revenue Metering instrument transformers will be used solely for the purpose of supplying the Revenue Metering equipment and for supplying transducers required for telemetering to MECL. No other equipment is permitted to be connected to the revenue metering instrument transformers. In the case of potential transformers, a dedicated secondary winding on a potential transformer will be considered to have met this requirement provided the VA burden rating of the potential transformer is not exceeded when the connected burdens on all secondary potential windings are added together.

F. Sealing of Metering Equipment

1. Where space is provided in customer owned equipment, all compartments containing revenue metering equipment, including terminal blocks, instrument transformers, meters, etc. must be sealable by MECL.

2. MECL Seals on revenue metering equipment are to be broken by MECL personnel only.

G. Communication Link

The Customer must provide a reliable telephone line and telephone line isolation or MECL acceptable equivalent, as required, to all revenue metering interval meters.

H. Outages Required to Repair Metering Equipment

Where the revenue metering equipment becomes inoperable and an outage to the

Facility's equipment is required to repair the metering equipment, the outage must be arranged by the Customer, with MECL consultation, within a reasonable time frame. While the revenue metering is out of service, metering will be estimated based on the information that is available to MECL.

I. Metering Equipment and Quantities Metered

1. Figure VI shows a typical metering installation for a generation interconnection on the Transmission System. Note that the metering is installed on the primary Transmission System in this figure.

2. Revenue Metering installations will have instrument transformers approved for revenue metering by Measurement Canada.

3. Revenue Metering installations will have a Main Revenue Meter and a separate Back-up Revenue Meter. Both meters will be approved by Measurement Canada.

4. Accuracy of the Revenue Meters must meet or exceed the 0.2% accuracy class of ANSI standard C12.20.

5. Revenue meters must be equipped with a minimum of 4 pulse outputs. These pulse outputs may be used by MECL for telemetering.

6. Each revenue meter will have a MECL approved test switch installed to permit on site testing of the metering installation.

7. Both the Main and Back-up bi-directional Revenue Meters will have a minimum of 6 interval data channels. Typically the following interval and register data will be recorded:

Energy (kWh) Flow From generator To MECL - Delivered

kWh Delivered – cumulative register and interval data

kVArh Lag – cumulative register and interval data

kVArh Lead – cumulative register and interval data

Energy (kWh) Flow From MECL To generator – Received

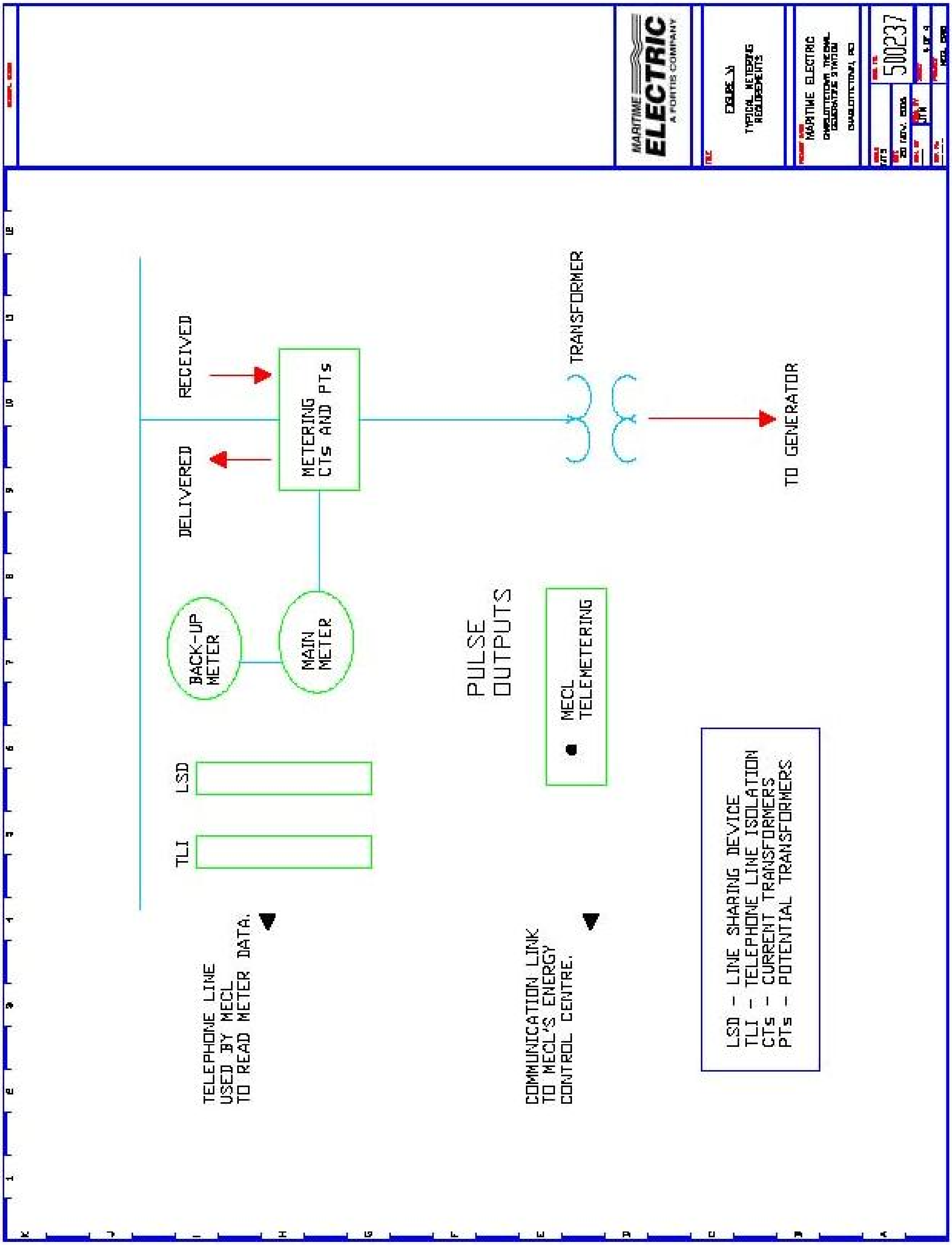
kWh Received – cumulative register and interval data

kVArh Lag - cumulative register and interval data

kVArh Lead - cumulative register and interval data

Max kW Demand – Register

Max kVA Demand – Register


RECEIVED
DELIVERED
METERING
CTs AND PTs
TRANSFORMER
TO GENERATOR
BACK-UP
METER
MAIN
METER
PULSE
OUTPUTS
MECL
TELEMETERING
LSD
TLI
TELEPHONE LINE
USED BY MECL
TO READ METER DATA.
COMMUNICATION LINK
TO MECL'S ENERGY
CONTROL CENTRE.
LSD - LINE SHARING DEVICE
TLI - TELEPHONE LINE ISOLATION
CTs - CURRENT TRANSFORMERS
PTs - POTENTIAL TRANSFORMERS
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TYPICAL METERING
REQUIREMENTS
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V. SUPERVISORY CONTROL AND DATA ACQUISITION

MECL employs a Supervisory Control and Data Acquisition System (SCADA) to monitor and control the Transmission System. This SCADA provides real time status and analog information of the Transmission System components by gathering information at each terminal/plant/switching station/substation via Remote Terminal Units (RTUs). These RTUs are interconnected by data communications facilities to the SCADA host computers in Charlottetown, Prince Edward Island. The host computers are used by Operations personnel who are responsible for power system operations. All generation facilities with 1 MVA or more of net generation must have an RTU to meet these requirements.

A. RTU Requirements

The Facility’s RTU must be compatible with MECL protocol for data communication. Communication equipment design and procurement must be reviewed and approved by MECL to ensure this compatibility.

The RTU must operate continuously to provide the information listed below. Any required maintenance or repair must be scheduled through the System Operator, and must be completed expeditiously to return the RTU to continuous operation.

B. Normal SCADA Requirements

Generators are required to install an RTU and shall provide for the following telemetry (the scan rates for all analog and digital data are 2 seconds).

1. Analog Data (for each generating unit)

- Unit Gross Real Power Output (Megawatts)
- Unit Gross Reactive Power Output (Megavars)
- Unit Net Real Power Output (Megawatts)
- Unit Net Reactive Power Output (Megavars)
- Common Station Service Real Power Load(Megawatts)

- Common Station Service Reactive Power Load (Megavars)
- Unit Output Voltage (Kilovolts)
- Manual High and Low Operation Limit for each Unit

2. Digital Data (for each generating unit)

- Unit Gross Hourly Energy Output (Megawatthours)
- Unit Net Hourly Energy Output (Megawatthours)
- Net Hourly Energy Input (Megawatthours) (where required)
- AVR Status
- Unit Disconnect Status
- Unit Breaker Status

C. Automatic Generation Control - Telemetry

For each unit participating in Automatic Generation Control (AGC), the following telemetry is required in addition to the SCADA requirements listed above.

1. Unit Control Status (local/remote)
2. Unit regulating low limit (Megawatts)
3. Unit regulating high limit (Megawatts)
4. Unit ramp rate (Megawatts/min)

D. Automatic Generation Control – Control Output

- Unit Control Output (Raise/Lower Adjustment) for remote control, a 1-second pulse out of the RTU is set to 1 MW of movement in the raise or lower direction. There is a separate raise and lower control output for each unit.

E. Automatic Generation Control – Tuning Parameters

The following tuning data is required from the Customer prior to commissioning the unit on AGC (does not have to be telemetered):

1. Net capacity
2. Minimum load
3. Disallowed regions (if any)

F. Additional SCADA Requirements

MECL, at its discretion, may require miscellaneous trouble alarms (if any) associated with the generator, such as:

1. Block Increase (status)
2. Block Decrease (status)
3. Runback in Progress (status)

G. SCADA Communication Requirements

The Customer is responsible for the cost to install and maintain continuous SCADA communications between the MECL SCADA computer in Charlottetown and their RTU at the generation facility. Information can be transmitted via a telephone company provided circuit or via a private communications carrier. The MECL Data Communications Network may be utilized for a fee to provide the connection to the MECL Energy Control Centre.

All Generation facilities are required to have 7 days-per-week, 24 hours-per-day repair capability for all SCADA circuits.

H. Wind Farm Information

1. Wind speed for each unit.
2. Wind Direction for each unit.

I. Setpoint Voltage

System Operator will be able to set voltage for the facility.

Wind facilities shall be able to provide sufficient dynamic voltage support so as to be able to hold the voltage, at the Delivery Point, constant at 1.0 per unit while operating at power factors in the range of +/- 0.98 and producing full real power output.

VI. POWER QUALITY

The following criteria are established to ensure that generation facilities within the utility service area provide the power quality expected by power consumers and other generators.

A. Voltage

The voltage from generators must be controlled so that MECL can maintain the distribution voltage within ± 5% of nominal. Voltage limits for generation facilities connected to the Transmission System will be determined by MECL. Any facility with synchronous generators may be required to provide voltage support to the Transmission System by operating their generator at any point within the generator's capability curve as directed by System Operations.

B. Flicker

Any sudden change in real or reactive power from the Customer's equipment is reflected as sudden voltage changes that can cause problems to equipment and also cause lights to flicker. Flicker limitations will be determined at the point of common connection based on IEEE Standard 1453, IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems and CSA-C61000-3-7:04 - Emissions Limits for Fluctuating Loads. No more than a 3% instantaneous variation in voltage is allowed when connecting or disconnecting any generator or station load to the Transmission System.

C. Harmonic Content

The harmonic content of the voltage and current waveforms on the Transmission System must be restricted to levels which will not cause any interference or equipment operating problems for customers. Minimum requirements for limitations of harmonic content on the Transmission System shall comply with IEEE Standard 519.

Harmonic problems will also be addressed on a complaint basis. If MECL determines that the Facility is the cause of a harmonic problem, then that generation must be removed from the Transmission System until the condition is resolved. In addition, all costs associated with research and corrective action, including settlements paid to other customers, will be at the Customer's expense.

D. Islanded Generation Limits

Under certain circumstances, MECL may request that the generator serve local distribution load while isolated from MECL. To accommodate these situations, the voltage and frequency limits will be specified by MECL. These will be reviewed and approved by MECL on a case-by-case basis.

VII. SAFETY (SWITCHING AND TAGGING PROCEDURES)

A. General

The interconnection of multiple generation facilities (possibly controlled by many independent companies) on the Transmission System introduces safety concerns. To mitigate these concerns:

- There shall be established communication between the generator operators and the System Operator.
- There shall be a clear division of operating control between the System Operator and the generator operator. This is normally the tie disconnect switch (high voltage generator disconnect switch).
- Each Customer shall have a code of practice that provides switching, tagging and grounding procedures that comply with the Occupational Health and Safety Act and the MECL Standard Protection Code.

- The generator operators shall be trained and be made aware of the operating authority of the System Operator.

B. Switching and Tagging

Strict adherence to established Switching, Tagging and Grounding procedures must be maintained for the safety and protection of all personnel. All operations of the tie disconnect shall be done under the MECL Standard Protection Code. This switch shall be able to be verified open by visual inspection and shall be lockable.

The System Operator shall provide the Customer with a list of all Customer personnel trained and qualified to operate this switch. This list shall be certified and maintained by the System Operator in accordance with the MECL Standard Protection Code.

Customer personnel not on the List of Qualified Persons shall not be permitted to operate the disconnect switch.

C. MECL Responsibility

MECL representatives shall carry out an inspection of the work area when MECL is required to work on a Customer's premises. If MECL believes that hazardous working conditions exist, the Customer shall be required to correct the unsafe condition before MECL shall commence work.

D. Generator Responsibility

The Customer is responsible for establishing a code of practice to comply with all required safety regulations and protection of personnel. Permission must be received from the System Operator before operating the tie disconnect.

When MECL is working on the Facility, it is the Customer's responsibility to ensure the equipment being worked on is isolated and de-energized in compliance with the MECL Standard Protection Code.

E. Switch Access

The Customer must provide MECL unrestricted, continuous access to the tie disconnect switch.

F. Energizing Apparatus

The Customer shall not energize any Transmission apparatus unless acting under the knowledge and direction of the System Operator.

VIII. OPERATIONS AND MAINTENANCE

Power consumers are affected by the Customer's operation and maintenance practices. Practices that promote high reliability will enhance the quality of service to all customers on the Transmission System.

A. Generator Interfacing

There are many events that will necessitate communications between MECL and the Customer. MECL and the Customer will provide each other a contact name, phone number, and address for the purpose of conducting ongoing business.

1. Operations

Customers may call the System Operator to discuss the status, availability or operation of the Facility. Requests for MECL to open/close the Facility's tie disconnect switch should be made to MECL as indicated in Section VII, “Safety “Switching and Tagging procedures”, of this document.

2. Metering

The metering package at the Customer's facility will be on a regular calibration schedule that is coordinated by MECL Metering Operations. This department will attempt to contact the Customer prior to actually calibrating these meters. The Customer can observe this procedure if desired.

B. Site Inspections

The following site inspections will be coordinated between the Customer and MECL.

1. Initial Inspection

The initial inspection includes the Customer's facility acceptance testing which must be conducted before the Facility will be allowed to generate in parallel with the Transmission System, as described in Section III.L, “Generator Facility Acceptance,” of this document. This inspection will also involve a discussion and observation of standard operation and safety procedures.

2. Annual Inspection

MECL will determine the necessity for an annual inspection. If conducted, it will include a visual inspection of the generator and switchgear rooms (where interconnection equipment is located) and a review of operation and maintenance procedures, pertinent documentation, and adherence to all applicable codes and standards.

3. Test and Inspection

This test and inspection will occur at least every five years after the initial inspection. Items of concern for the annual inspection will be reviewed and a test of the interconnection system will be performed per Section VIII.E.1, “Interconnection Protection System”. This test will include input verification testing, overall protection system operability, and calibration of protective relays. Input verification testing will include verification of PT and CT circuits, transformer ratios, and DC trip source availability. The overall protection system operability will entail verification of trip circuits including a trip test of each breaker tripped by the interconnection relaying. Calibration of relays will verify the setpoints and confirm the ability of the protective devices to respond within specified parameters. At the sole discretion of MECL, more frequent testing may be required.

Protective Interconnection Relay calibration testing must be performed by a qualified contractor and observed by MECL. At the Customer's option, this testing may be performed by MECL. Verification of setpoints will be in accordance with MECL specifications.

C. Site Access

MECL will require site access for the following reasons:

1. Routine Access

MECL will require access to the Customer's facilities to perform the inspections and tests detailed in this document as well as for other business needs. Normally, this access will be coordinated and scheduled by phone so as to enable each party to conduct the necessary business with minimum impact to the other party.

D. Operational Requirements

Utility Transmission Systems are designed to provide safe, reliable service to all customers. Facilities operating in parallel with the Transmission System must not operate in a manner that results in unacceptable service to customers. Facilities whose operation of equipment results in unacceptable service to customers or adversely affects the Transmission System must immediately correct any problems by performing modifications to equipment as necessary to prevent the recurrence of those problems. If necessary, MECL will discontinue the facility interconnection service until the problems have been corrected.

During maintenance, testing, or repair of Transmission facilities, MECL may request the Customer to discontinue parallel operations. Such maintenance may require opening of the tie disconnect switch. The following operating requirements are necessary to ensure reliable service and that the operation of generation equipment does not cause any adverse affects on the Transmission System.

1. Voltage Control

The Customer must automatically adjust generation to maintain adequate voltage regulation under a variety of operating conditions. The distribution voltage to all customers must be maintained within ±5% of nominal voltage as specified by MECL. The Customer must employ an automatic method of disconnecting generation equipment from the Transmission System if the system voltage cannot be maintained within tolerance. All generators must be equipped with an Automatic Voltage Regulator and it must remain in-service unless authorized by the System Operator.

2. Reactive Power

To prevent the degradation of system voltage to MECL customers as a result of interconnection with a Customer's Facility, Facilities generate such reactive power as may be reasonably necessary to maintain voltage levels and reactive area support.

3. Speed Control

All other than non-dispatchable generators must be equipped with an automatic frequency sensitive speed-governing system capable of achieving a 4% droop characteristic.

4. System Performance Reporting

For MECL to adequately assess the performance of its system, ensure compliance with regulatory requirements, and provide conformance reporting to NPCC and the NBSO, Customers will be required to submit the following operational information:

- Continuously (Units Larger than 1 MVA): Accurate and reliable metering and information regarding status and the output (MW, MVAr, kV, MWh, and alarms) of the Facility as specified in Section V, "Supervisory Control and Data Acquisition".

- When Available: Information about whether the Facility has capability for participation in system restoration or has black start capability.
- Each Year or as Required: Maintenance schedules for the generator, step-up transformer, tie breaker, and protection system. Setpoint verification on all underfrequency/ overfrequency relays or underspeed/overspeed devices which are not part of the Interconnection Protection Equipment.
- After Outages or Relay Operations: Information about any outage or interconnection relay operation involving the Customer's facility as per MECL instructions within two (2) working days.

E. Testing and Maintenance

The Customer will have full responsibility for the routine testing and maintenance of the interconnection equipment, including the Interconnection Protection System, the Generator Protection System, the Generator Step-up Transformer, the Interconnection Circuit Breaker, and the Station Battery and Charging System. MECL will monitor maintenance on the Interconnection Equipment, including protection system(s), transformer(s), Interconnection Circuit Breaker(s), and Station Battery(ies) and Charging System(s), etc.

MECL is primarily interested in the performance of the total facility to ensure that the facility operates with no adverse impact to the Transmission System. Therefore the Customer is expected to maintain the generator and all of its support systems. The Customer is also responsible for tree trimming and vegetation control in accordance with MECL vegetation control standards for any portion of the interconnection where a fault could affect the operation of the MECL Transmission System.

As a minimum, Customers must perform all periodic maintenance and testing according to: The recommended manufacturer's maintenance and test guidelines; the requirements specified in this document; and specifications found in reference documentation of controlling authorities.

Maintenance records are required to be maintained and must be made available to MECL during the annual inspections and other inspections. Specific equipment test data must be made available to MECL upon request to provide evidence that the equipment will operate as intended. Failure of the Customer to provide proper testing and maintenance will result in the Customer being notified and requested to take prompt corrective action within ten (10) days. Should the Customer then fail to provide the proper testing and maintenance, MECL will discontinue the facility interconnection service until appropriate corrective action is taken and MECL approval is obtained.

If the interconnection equipment is not properly maintained, fails to perform its intended function, or has been modified from that approved by MECL, then MECL will give notice to correct the area of noncompliance or will open the interconnection. The time allowed for the Customer to comply, while remaining on line, will depend upon an MECL assessment of the safety, reliability, and performance issues relating to the noncompliance.

MECL may inspect any of the interconnection equipment, including the protection systems, whenever such an inspection is deemed necessary by MECL. This inspection may include tripping of the interconnection and/or generator circuit breaker(s). The Customer shall bear the cost of any necessary testing that may be requested by MECL.

All outage schedules and maintenance work will be coordinated through MECL.

The Customer must implement a maintenance program consistent with acceptable industry practice so as to achieve a highly reliable interconnection. During site visits, MECL representatives will be interested in checking maintenance records and performing testing as follows:

1. Interconnection Protection System

The Customer must perform a relay calibration test at least every five (5) years using equipment of known accuracy. This biennial test shall include calibration and operational tests of individual relays and functional tests of the subsystems and the total system. Calibration checks will include verification of setpoints and voltage and current measurements. Operational and functional tests will include as many trips of the tie and/or generator breaker(s) as necessary, a synchronizing test, and any other test as may be required by MECL. Transfer trip equipment, where installed, will also be tested. During the operational test, up-to-date design drawings must be made available to MECL personnel to allow for safe, reliable testing of the Facility.

2. Interconnection Circuit Breakers/Reclosers and Transformers

The Customer will perform maintenance on these devices at a maximum interval not to exceed five (5) years. The Customer must provide to MECL the identity and qualifications of the personnel who perform this maintenance and any associated testing. This maintenance must be coordinated with the Energy Control Centre to obtain the proper zones of clearance.

3. Station Battery and Charging System

Batteries associated with the Interconnection Protection System must have a high degree of reliability. To ensure that the Interconnection Protection System performs its intended function, the Customer must implement a battery preventative maintenance program to include periodic battery inspections and testing as approved by MECL. The reports from these battery inspections and tests shall be maintained by the Customer and made available for review by MECL personnel during the periodic tests and inspections of the facility and at other times as requested by MECL.

Battery Inspections: The preventative maintenance program will include monthly battery inspections to measure and record, as a minimum, overall battery voltage and the following parameters on a pilot cell: voltage, specific gravity (where applicable), fluid level (where applicable), and temperature. Quarterly, these readings will be taken and recorded on each battery cell. Also on a quarterly basis, an indication of battery condition (cleanliness, presence of corrosion, condition of battery leads and connections) will be recorded with notes of any corrective maintenance performed.

A high-rate charge will be performed as required, or battery cells replaced, if the cells are not within the manufacturer's recommendations or applicable IEEE Standards, or if a trend of reduced cell voltage is detected. Where inspection data is incomplete or indicates battery deterioration or improper maintenance, MECL will require the completion of a battery capacity test or replacement of the battery.

During the biennial test and inspection, the Customer may be required to perform a battery inspection in the presence of an MECL representative. The results of this inspection will be reviewed by MECL for compliance with this station battery preventive maintenance requirement.

Battery Testing: The Customer must perform a battery capacity (load discharge) test on the station battery that provides tripping power for the Interconnection Protection System. This load discharge test must prove that the station battery retains at least 80% of its rated capacity. If the capacity falls below 80%, the battery must be replaced. An initial battery capacity test shall be done prior to battery installation and commissioning. Additional tests will be done at least every five years during the battery's operational life, in accordance with the latest applicable IEEE Standards and manufacturer’s specifications.

Load testing, as approved by MECL on a case-by-case basis, may be used as an alternative to capacity testing. To obtain approval for load testing, the Customer will supply MECL with a proposed battery test program certified by a professional engineer. The professional engineer must certify that the battery test program will yield test results that reliably indicate the battery has ample capacity to meet the needs of the generation facility.

Results of all station battery tests must be provided to MECL.

Battery Charging: A normal float charge will be maintained on the battery and a high-rate (equalizing) charge will be performed periodically as recommended by the manufacturer or applicable IEEE standards. The battery must be cleaned and each cell must be appropriately and conspicuously marked with a cell number for reference. Where applicable, cell fluid levels must be maintained with appropriate replacement fluid, in accordance with manufacturer's recommendations.

F. NERC Planning Standards

For facilities interconnected to the utility Transmission System, the Customer is required to meet North American Electric Reliability Council (NERC) Planning Standards. This standard requires physical testing to be performed to verify that actual equipment performance matches design data. Parameters to be verified include generator gross and net capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems. These standards include requirements for the following testing and information (detailed requirements for these tests must be approved by MECL):

- The Customer shall annually verify the gross and net summer and winter capability of each unit.
- Every five (5) years, the Customer shall perform a test to verify the gross and net reactive capability, leading and lagging, of their units.
- Every five (5) years, the Customer shall test voltage regulator controls and limit functions, speed/load governor controls, and excitation systems to verify equipment performance against design specifications.

G. Technical Data – Generator

The following pages up to Schedule C contain technical data and other information respecting the [Insert Customer/Facility Name] Facility.

- Generator Data
- Generator Set-Up Transformer
- Excitation System Data
- Power System Stabilizer Data
- Governor and Prime Mover Data
- Intertie Protection System Data
- Feeder Management Relays
- Synchronizing Procedure
- Diagrams
  - Key One Line Diagram
  - Breaker Synchronization
  - Three Line Diagram Generator Metering
  - Interconnect Wiring Diagram Customer

SCHEDULE C

CONSTRUCTION SCHEDULE

Construction Schedule

MECL and the Customer have negotiate in good faith concerning a schedule for the construction of EMCL's Interconnection Facilities and network Upgrades. The schedule below reflects those negotiations:

[INSERT CONSTRUCTION SCHEDULE HERE]

SCHEDULE D

REVENUE METERING EQUIPMENT AND COSTS

Location/Description	Description	Capital	Non Capital Cost	Total Cost
Revenue Metering Meters				
Meter Item A				
Meter Item B				
Meter Item C				
Subtotal Meters				
Revenue Metering Communications				
Telemetry Item A				
Telemetry Item B				
Telemetry Item C				
Subtotal Communications				
Revenue Metering Transformation				
Transformation Item A				
Transformation Item B				
Transformation Item C				
Subtotal Transformation				
Grand Total				

Loss Compensation Details

The monthly operating and maintenance charge for metering shall be included in Schedule 9 of MECL's OATT.

SCHEDULE E
BLACKSTART CRITERIA

1.0 Definition

Following a system-wide outage (blackout), it is necessary to establish initial generation that can supply a source of electric power to other system generation and begin system restoration. These initiating generators are referred to as system blackstart generators.

A blackstart generator must be able:

- to self start without any source of offsite electric power to help create a source of generation that can maintain adequate voltage and frequency while energizing isolated transmission facilities and auxiliary loads of other generators.

2.0 Tests

All facilities designated as blackstart capable shall have this capability tested annually without dependencies on power sources not available during a partial or complete system blackout.

Once the facility has been started, it shall continue to demonstrate the capability by operating in a stable condition while isolated from the power system for a minimum of ten minutes.

The number of generators within a facility that shall be blackstarted for this test is determined by the Control Area as needed by the Control Area's system restoration plan.

All operating aids and auxiliary systems used in blackstarts, such as operations voice communications and system control and data acquisition (SCADA), shall be verified to operate adequately without dependency on the interconnected system or other unrelated generator support for any source of station service. Station service transfer schemes will also be tested as part of the blackstart test.

Transmission egress capability to deliver blackstart generation to the next substation shall be verified.

3.0 Black Start Reporting

The facility owner/operator is responsible to carry out blackstart testing.

Request to carry out full facility test should be submitted to the Energy Control Centre Outage Coordinator at least 5 working days prior.

Once the test is completed the blackstart facility will report test results verbally to the Energy Control Centre within 24 hours.

A written report will be submitted to the Manager, Production and Energy Supply at the Energy Control Centre within one month of test completion. This report will:

- Outline site location
- Date of test
- Test results
- Reasons for failure if needed
- Remedial actions required and expected completion date of remedial actions

Documentation must be kept for a period of three years.

4.0 Reference Documents

This document is written to comply with NPCC Document A-03 (Emergency Operation Criteria).

SCHEDULE F

INSURANCE REQUIREMENTS

1.0 Customer agrees to provide and/or cause its subcontractors to provide and maintain in full force and effect with financially responsible insurance carriers acceptable to MECL, the following insurance which shall take effect as of the date of this agreement and shall remain in effect during the term hereof or any extension thereof or as otherwise specified herein:

1.01 Workers Compensation as required by the Prince Edward Island Workers Compensation Act or similar applicable legislation covering all persons employed by Contractor or its subcontractors for work performed under this contract. For U.S. employees, appropriate State Workers Compensation must be carried including Employer's Liability for a minimum limit of $1,000,000 U.S., with a Foreign Coverage Endorsement and, to the extent applicable, Jones Act and U.S. Longshoreman's and Harbor Workers coverage and FELA.

1.02 Automobile Liability Insurance, covering all licensed motor vehicles owned, rented or leased and used in connection with the work to be performed under this agreement covering Bodily Injury and Property Damage Liability to a combined inclusive minimum limit of $2,000,000 and mandatory Accident Benefits.

1.03 Commercial General Liability and Excess Liability Insurance on an occurrence basis in an amount not less than $5,000,000 inclusive for both bodily injury, including death, personal injury and damage to property, including loss of use thereof, for each occurrence.

Coverage shall specifically include but not be limited to the following:

i. Blanket Contractual Liability;

ii. Damage to property of the MECL including loss of use thereof;

iii. Products and Completed Operations including a provision that such coverage to be maintained for a period not less than 24 months post Final Performance;

iv. Employer's Liability;

v. Tenant's Legal Liability;

vi. Non-Owned Automobile Liability; and,

vii. Broad Form Property Damage

Excess Liability Insurance also to be excess of the coverage's under sections 1.01 (Workers Compensation – to the extent coverage includes Employer's Liability) and 1.02 (Automobile Liability).

1.04 "All Risk"" property insurance as applicable to a limit of the value of the full replacement cost of the facility any one occurrence covering physical loss or damage to the facility.

1.05 Pollution Liability Insurance: The Customer will purchase a policy with limits of not less than $5,000,000 per occurrence covering bodily injury and property damage claims, including cleanup costs as a result of pollution conditions arising from Customer operations.

General Insurance Conditions

1. Certificates of Insurance:

i. Before starting work, the Contractor will supply and cause its subcontractors to supply MECL a certificate of insurance completed by a duly authorized representative of their insurer certifying that at least the minimum coverages required here are in effect and that the coverages will not be cancelled, nonrenewed, or materially changed by endorsement or through issuance of other policy(ies) of insurance which restricts or reduces coverage, without 60 days advance written notice by registered mail, or courier, receipt required, to:

Maritime Electric Company, Limited
PO Box 1328, 180 Kent Street
Charlottetown PE C1A 7N2

ii. Failure of MECL to demand such certificate or other evidence of full compliance with these insurance requirements or failure of MECL to identify a deficiency from evidence provided will not be construed as a waiver of the Customer's obligation to maintain such insurance.

iii. The acceptance of delivery by MECL of any certificate of insurance evidencing the required coverages and limits does not constitute approval or agreement by MECL that the insurance requirements have been met or that the insurance policies shown in the certificates of insurance are in compliance with the requirements.

iv. If the Customer fails to maintain the insurance as set forth here, MECL will have the right, but not the obligation, to purchase said insurance at the Customer's expense. Alternatively, the Customer's failure to maintain the required insurance may result in termination of this contract at MECL's option.

2. All deductibles shall be to the account of the Customer.

3. With the exception of clause 1.02 (Automobile Liability), all insurance noted above shall specify that it is primary coverage and not contributory with or in excess of any other insurance that may be maintained by MECL.

4. All limits and deductibles are expressed in Canadian dollars.

5. A waiver of subrogation shall be provided by the insurers to MECL's, Contractor, subcontractors and Project Manager for coverages 1.01 (Workers Compensation – U.S. only), 1.03 (Contractor's Equipment).

6. MECL shall be included as additional Named Insured under coverages noted in (Commercial General Liability and Excess Liability), and as an Additional Insured under coverages (Aircraft Liability), and (Pollution Liability.

7. Coverages noted in 1.03 (Commercial General Liability and Excess Liability), and 1.06 (Pollution Liability) shall contain a Cross Liability clause and a Severability of Interests clause.

8. Contractor shall provide MECL with certified copies of insurance policies upon request.

SCHEDULE G
PRE-CONTRACT COSTS

This schedule defines all costs incurred by MECL that the generator is responsible for paying for. This includes but not limited to:

- Interconnection Request Deposit
- Facilities Studies
- System Impact Studies
- Engineering and Procurement Agreement Costs

SCHEDULE H

GENERATOR CAPABILITY CURVE

A graphical representation of the generator's Megawatt and Megavar capability is to be provided by the generator owner or his representative for inclusion in the Interconnection Agreement.

SCHEDULE I
INTERCONNECTION FACILITIES CHARGES

MECL shall determine the annual charges for Interconnection Facilities Support Charges – Non-Capital Related (IFSC-NCR) as shown and described in this Schedule I.

Description:

a. "Total Plant Construction Costs" shall be MECL's original construction costs, inclusive of all project overhead OM&A costs, plus any improvements, as defined on MECL's plant accounting records. These costs are classified as Direct Assignment Facilities and Other Direct Assignment Facilities as defined in Section 1 of this Agreement.

b. "Shared Construction Costs" shall be the amount of Total Plant Construction Costs, pursuant to the Tariff covered either through other interconnection agreements or added to the Tariff rate base.

c. "Total Plant Construction Costs Recoverable from Customer" shall equal the Total Plant Construction Costs less the Shared Construction Costs.

d. The "Metering per Schedule D of Interconnection Agreement" shall equal MECL's cost, as set forth in Schedule D, related to the construction or installation on Customer's behalf of all Revenue Meters.

e. "Customer's Expected Final Responsibility" shall equal the Total Plant Construction Costs Recoverable from Customer plus the Metering Per Schedule D of Interconnection Agreement.

f. The "Capital Charges Subject to Support" shall equal the Customer's Final Expected Responsibility less any non-capitalized construction costs not subject to support, as determined by MECL, less the overhead operation, maintenance and administration.

g. "Non-Capital Support Charge Rate" shall equal the OM&A related carrying charge as defined by and calculated pursuant to Schedule 9 of MECL's currently effective OATT. The OM&A related carrying charges calculated pursuant to Schedule 9 shall include, without limitation, the direct and indirect OM&A expense.

h. The "IFSC-NCR Annual Cost" shall be the Capital Charges Subjected to Support multiplied by the Non-Capital Support Charge Rate plus all time, material and other charges incurred by MECL to operate, maintain, repair and renovate all Direct Assignment Facilities and Other Direct Assignment Facilities as defined in Section 1 of this Agreement including Metering and associated equipment described in Section D of this Agreement.

Payment Option:

Customer will pay monthly as costs are incurred and billed by MECL for the Total Plant Construction Costs, including the Metering Per Schedule D of Interconnection Agreement, as determined by application of the Formula in this Schedule I. The Customer will retain the obligation pursuant to this Schedule I until MECL has recovered all its costs associated with the constructed or updated facilities or until any unrecovered investment is included for recovery in the MECL OATT.

Upon Customer's payment to MECL for the removal of said facilities, Customer's obligation for IFSC-NCR annual cost shall terminate and MECL shall remove said facilities in due course.

Updates:

The Customer is on notice that the IFSC-NCR annual costs, as determined by MECL pursuant to the Formula in this Schedule I, will be updated annually. The update will reflect changes in the OM&A carrying charge that may result from using the most recent calendar year data or such supporting data to calculate the non-capital related carrying charges pursuant to MECL's OATT.

The charges in this Schedule I, including the "Capital Charges Subject to Support", will be updated if MECL determines that any additions, modifications or upgrades to MECL's transmission system are required as a result of the Customer proposing to materially change the electrical characteristics or increase the capacity of the Facility connected to MECL's transmission system. MECL will charge the Customer the incremental cost if such additions, modifications or upgrades are required. MECL, at its sole discretion, can require that these costs be paid in advance. If MECL requires a lump sum payment in advance, the Customer will pay the actual construction costs, and the Net Present Value over the term of the agreement of the OM&A related charges for the direct and indirect OM&A expense.

SCHEDULE J
INTERCONNECTION REQUEST PROCEDURES

General

An interconnection Customer shall submit to the Transmission Provider a completed Generator Interconnection Request Form and a refundable deposit of $10,000. The Transmission Provider shall apply the deposit toward the cost of a System Impact Study. The Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. The interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two interconnection requests.

At the interconnection Customer's option, the Transmission Provider and interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the System Impact Study Agreement.

System Impact

The Study consists of short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The stability and steady state studies would identify necessary upgrades to allow full output of the proposed Generating Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Generating Facility without requiring additional Network Upgrades.

Initiating an Interconnection Request

To initiate an Interconnection Request, interconnection Customer must submit all of the following:

i. a $10,000 deposit,
ii. a completed Generator Interconnection Request Form
iii. demonstration of Site Control or a posting of an additional deposit of $10,000.

Such deposits shall be applied toward any System Impact Studies pursuant to the Interconnection Request. If interconnection Customer demonstrates Site Control within the cure period specified below after submitting its Interconnection Request, the additional deposit shall be refundable; otherwise, all such deposit(s), additional and initial, become non-refundable.

The expected In-Service Date of the new Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the process window for the Transmission Provider's expansion planning period) not to exceed seven years from the date the interconnection Request is received by the Transmission Provider, unless the Interconnection Customer demonstrates that engineering, permitting and construction of the new Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by the Transmission Provider by a period up to ten years, or longer where the interconnection Customer and Transmission Provider agree, such agreement not to be unreasonably withheld.

Acknowledgement of Interconnection Request

Transmission Provider shall acknowledge receipt of the Generator Interconnection Request Form within ten (10) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement.

Deficiencies in Interconnection Request

An Interconnection Request will not be considered to be a valid request until all items listed above have been received by the Transmission Provider. If an Interconnection Request fails to meet the requirements set forth above, the Transmission Provider shall notify the interconnection Customer within ten (10) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request.

Interconnection Customer shall provide the Transmission Provider the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. In the case of failure by interconnection Customer to supply the requested information, the transmission Provider shall deem the interconnection Request to be withdrawn and shall provide written notice to the Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal.

Upon receipt of such written notice, the interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify the Transmission Provider of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of the interconnection Customer's Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, the Interconnection Customer's Interconnection Request is eliminated from the queue until such time that the outcome of Dispute Resolution would restore its Queue Position. An interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to the Transmission Provider all costs that the Transmission Provider prudently incurs with respect to that Interconnection Request prior to the Transmission Provider's receipt of notice described above. The interconnection Customer must pay all monies due to the Transmission Provider before it is allowed to obtain any System Impact Study data or results.

The Transmission Provider shall refund to the interconnection Customer any portion of the interconnection Customer's deposit or study payments that exceeds the costs that the Transmission Provider has incurred, including interest. In the event of such withdrawal, the Transmission Provider, subject to confidentiality constraints, shall provide, at interconnection Customer's request, all information that the Transmission Provider developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

Scoping Meeting

Within ten (10) Business Days after receipt of a valid Interconnection Request, Transmission Provider shall establish a date agreeable to interconnection Customer for the Scoping Meeting, and such date shall be no later than 30 Calendar Days from receipt of the valid Interconnection Request, unless otherwise mutually agreed upon by the Parties.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection.

Transmission Provider and interconnection Customer will bring to the meeting such technical data, including, but not limited to:

i. general facility loadings;
ii. general instability issues;
iii. general short circuit issues;
iv. general voltage issues, and
v. general reliability issues as may be reasonably required to accomplish the purpose of the meeting.

Transmission provider and interconnection Customer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, interconnection Customer shall designate its Point of Interconnection and one or more available alternative Point(s) of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

Generator Interconnection Request Form
Page 1 of 3

MARITIME ELECTRIC A FORTIS COMPANY

The undersigned Interconnection Customer submits this request to interconnect its Generating Facility with the Transmission Provider's Transmission System pursuant to a Tariff. A valid Interconnection Request must include an applicable deposit amount as specified in the Generator Interconnection Agreement (Attachment J – Schedule J).

Application Information

Applicant	Company Name:	Street Address:
	Contact Name:	Unit/Suite:
	Phone:	City:
	Fax:	Province:
	E-mail:	Country:
		Postal/Zip Code:

Project Information

Project	Name:	Project Location:
	Owner/Developer:	Point of Interconnection Requested:
	Engineering Consultant:	Proposed In-Service Data: yy/m

This Interconnection Request is for (check one):

❒ A proposed new Generating Facility.
❒ An increase in the generating capacity or a Material Modification of an existing Generating Facility.

The Type of Interconnection Service Requested (check one): (GIP 3.2)

❒ Energy Resource Interconnection Service ☐ Network Resource Interconnection Service

Maximum Megawatt Electrical Output of the Proposed New Generating Facility:

☐ MW summer at ☐ degrees C ☐ MW winter ☐ at degrees C

OR

☐ MW increase in the generating capacity of an existing Generating Facility

Evidence of Site Control as specified in Attachment J

❒ Is attached to this Interconnection Request
❒ Will be provided at a later date in accordance with Attachment J

This Interconnection Request is submitted by:

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request and Equipment Information Form is true and correct.

Name of Interconnection Customer (Type of Print): ____________ Title: ____________

Signature: ____________ Date: ____________

Contact Information – Send Completed Form in Hard Copy to:

Maritime Electric Company, Limited
PO Box 1328, Charlottetown PE C1A 7N2
Attention: Director, Corporate Planning

Maritime Electric Company, Limited – Generator Interconnenction Coodinator Use

Received by: ____________ Date and Time Received: ____________

Signature: ____________

Generator Interconnection Request Form
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GENERATING FACILITY DATA					
Application Information					
kVA		Degrees C		Voltage	
Power Factor				Connection (e.g. wye)	
Short Circuit Radio				Frequency (hz)	
Stator Amps at Rated kVA				Field Volts	
Max MW		Degrees C		Speed (RPM)	

Combined Turbine-Generator-Exciter Inertia Data					
Inertia Constant	H		kW-sec/kVA	Moment-of-Inertia		lb.-ft.^{2}

Reactance data (Per Unit-Rated kVA)				
	Direct Axis		**Quadrature Axis**	
Synchronous – saturated	X_{dv}		X_{qv}	
Synchronous – unsaturated	X_{di}		X_{qi}	
Transient – saturated	X'_{dv}		X'_{qv}	
Transient – unsaturated	X'_{di}		X'_{qi}	
Subtransient – saturated	X''_{dv}		X''_{qv}	
Subtransient – unsaturated	X''_{di}		X''_{qi}	
Negative Sequence – saturated	$X2_v$			
Negative Sequence – unsaturated	$X2_j$			
Zero Sequence – saturated	$X0_v$			
Zero Sequence – unsaturated	$X0_j$			
Leakage Reactance	Xl_m			

Field Time Constant Data (SEC)				
Open Circuit	T'_{do}		T'_{qo}	
Three-Phase Short Circuit Transient	T'_{d3}		T'_q	
Line to Line Short Circuit Transient	T'_{d2}			
Line to Neutral Short Circuit Transient	T'_{d1}			
Short Circuit Subtransient	T''_d		T''_q	
Open Circuit Subtransient	T''_{do}		T''_q	

Armature Time Constant (SEC)			
Three Phase Short Circuit	T_{a3}		
Line to Line Short Circuit	T_{a2}		
Line to Neutral Short Circuit	T_{a1}		

NOTE: If information requested above is not applicable, indicate by marking "N/A".

MW Capability and Plant Configuration – Generating Facility Data

Armature Winding Resistance Data (Per Unit)				
Positive	R1			
Negative	R2			
Zero	R0			
Rotor Short Time Thermal Capacity	1_2^2t			
Field Current at Rated kVA, Armature Voltage and PF				AMPS
Field Current at Rated kVA and Armature Voltage, 0 PF				AMPS
Three Phase Armature Winding Capacitance				MICROFARAD
Field Winding Resistance		OHMS		C
Armature Winding Resistance (Per Phase)		OHMS		C

Generator Interconnection Request Form

Page 3 of 3

Curves					
Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction Curves. Designate normal and emergency Hydrogen pressure operating range for multiple curves.					
Generator Step-Up Transformer Data					
Capacity kVA	Self Cooled	kVA	Max. nameplate		
Voltage ratio	Generator Side	kV	System Side		
Winding Connections	Low Voltage	❒ Wye	OR	❒ Delta	
	High Voltage	❒ Wye	OR	❒ Delta	
	Tertiary Voltage	❒ Wye	OR	❒ Delta	
Fixed Taps Available					
Impedance					
Positive Z1	(one self-cooled rating)	%			
Zero Z0	(one self-cooled rating)	%			
Excitation System Data					
Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation is power system stability simulations and the corresponding excitation system and PSS constants for use in the model.					
Governor System Data					
Identify appropriate IEEE model block diagram of governor system for computer representation is power system stability simulations and the corresponding excitation system constants for use in the model.					
Wind Generators					
Number of generators to be interconnected pursuant to this Interconnection Request:					
Evaluation		Single Phase		Three Phase	
Converter:	Manufacturer:		Model Number:		
	Model Name:		Version:		
List of adjustable set points for the protective equipment of software:					
Note: A completed PT1-PSS/E data sheet for the WEC must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device then they shall be provided and discussed at Scoping meeting.					
Induction Generators					

Field Volts:	
Field Amperes:	
Motoring Power (kW):	
Neutral Grounding Resistor (if applicable):	
I_2^2t or K (Heating Time Constant):	
Rotor Resistance:	
Stator Resistance:	
Stator Reactance:	
Rotor Reactance:	
Magnetizing Reactance:	
Short Circuit Reactance:	
Exciting Current:	
Temperature Rise:	
Frame Size:	
Design Letter:	
Reactive Power Required in Vars (No Load):	
Reactive Power Required in Vars (Full Load):	
Total Rotating Inertia, H:	

SCHEDULE K

GENERATION INTERCONNECTION AGREEMENT

WIND FARMS AMENDMENT

This Generation Interconnection Agreement Wind Farms Amendment (this "Schedule K") dated as of the Signing Date is by and between the ___________________________________ ("______") and Maritime Electric Company, Limited ("MECL"). ______ and MECL are referred to individually as a "Party" or collectively as the "Parties".

WHEREAS, simultaneously with the execution hereof, the Parties are signing a Generation Interconnection Agreement dated as of the Signing Date including all schedules and attachments thereto (the "Agreement");

WHEREAS, the form of Generation Interconnection Agreement has been approved on an interim basis by IRAC;

WHEREAS, in connection with the interconnection of facilities involving a wind farm, the Parties desire to provide for amendments to the form of Generation Interconnection Agreement that received IRAC approval on an interim basis;

WHEREAS, the Parties are signing this Schedule K to the form of Generation Interconnection Agreement, which shall be deemed an amendment to the Agreement;

WHEREAS, this Schedule K, for the avoidance of doubt, shall be a Schedule to the Agreement and form a part of the Agreement;

NOW THEREFORE, in order to carry out the transactions contemplated in this Schedule K and the Agreement, and in consideration of the mutual covenants and agreements hereinafter set forth, the Parties hereto, intending to be legally bound hereby, agree as follows:

1. ***General.*** Capitalized terms used but not defined in this Schedule K shall have the meanings ascribed to such terms in the Agreement. This Schedule K shall form a part of the Agreement and be incorporated therein as a Schedule provided that in the event of any conflict or inconsistency between this Schedule K and the rest of the Agreement, this Schedule K shall prevail. All references within the Agreement to "Agreement" or to "Schedules" shall include this Schedule K.

2. ***Definitions.*** Within the Agreement,

   a. all references to "Generator", "generator", "generators", "generating unit" or "unit" are replaced with "distributed wind generator" or "distributed wind generators", as the case may be;
   b. all references to "AGC" are replaced with "AFC";
   c. all references to "Automatic Generation Control" and "automatic generation control" are replaced with "Automatic Facility Control";
   d. all references to "AVR", "Automatic Voltage Regulator" and "automatic voltage regulator" are replaced with "Voltage Set Point Control";
   e. all references to "biennial tests and inspections", "biennial test and inspection" or "biennial test" are replaced with "tests and inspections in accordance with Good Utility Practice";
   f. "Commercial Operation Date" shall mean the first day that a transmission facility is energized for commercial use after all Facility testing and commissioning has been completed enabling the Customer to transmit up to _____MW into MECL's ___ kV Transmission System;
   g. "business practices" means MECL's business practices of general application developed from time to time by MECL in accordance with Good Utility Practice and provided to the Customer. Customer may refer the issue of whether the Customer should be bound by a business practice for resolution pursuant to Section 13 of this Agreement in which case the Customer shall be bound by such business practice from the time of implementation by MECL until final resolution

as provided under Section 13 and thereafter shall only be bound as provided for by such final resolution. MECL agrees, except in an Emergency, to provide Customer with advance notice of changes in business practices or of new business practices and to provide an opportunity for comments and input from Customer prior to implementation thereof.

3. ***Term***

a. Section 2.1 of the Agreement is amended and restated in its entirety as follows:

"**2.1 Term** - Subject to required regulatory authorizations, this Agreement will become effective on the Commercial Operation Date (the "Effective Date") notwithstanding the Signing Date; provided, however, the Agreement shall be legally binding when signed by the Parties as of the Signing Date. Except as provided below, this Agreement will remain in effect until 12:01 a.m., local time, on the date that is ______ (__) years after the Signing Date. Notwithstanding the previous sentence, the Agreement may be (a) terminated on an earlier date by mutual agreement of the Parties, or (b) otherwise terminated in accordance with the terms of this Agreement. The Term shall end on the date of termination or expiration. MECL will submit this Agreement to IRAC."

b. Section 2.3 of the Agreement is amended and restated in its entirety as follows:

"**2.3 Survival of Certain Provisions -** The applicable provisions of this Agreement will continue in effect after expiration or termination hereof to the extent necessary to provide for final billings, billing adjustments and the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect. These provisions include, without limitation, Section 3.2

("Licence and Access Rights"), Section 10 ("Indemnification"), Section 11 ("Insurance"), and Section 19 ("Limitation of Liability"). Upon termination of this Agreement prior to the expiration of the Term, Customer shall pay any removal and abandonment costs MECL may incur, and any associated costs, or shall continue to pay the charges set forth in Schedule I and Schedule D until the expiration of the original Term without such termination; provided that Customer shall not have to pay such costs or charges in the event of termination due to an Event of Default by MECL or an event of Force Majeure."

4. ***Obligations and Responsibilities***

a. Section 3.2.6 of the Agreement is deleted.

b. Section 3.3.1.2 of the Agreement is amended and restated in its entirety as follows:

"3.3.1.2 - Customer will submit for approval by September 30th of each year, its planned annual generator, collection circuit and substation maintenance schedules for the subsequent calendar year to the System Operator. The System Operator's approval shall be based on MECL's obligation to its customers for reliability of the MECL System consistent with Good Utility Practice. Any subsequent changes to this schedule must be approved by the System Operator. Customer will also furnish the System Operator with a non-binding five (5) year projected generator, collection circuit and substation maintenance schedules by September 30th of each year for the subsequent five calendar years."

c. Section 3.4.3 of the Agreement is amended and restated in its entirety as follows:

"3.4.3 As a result of any change in law, regulation or Good Utility Practice, at the request of MECL, acting in accordance with Good Utility Practice, the Customer, at its expense, will modify the Customer-Owned Interconnection Facilities and the Facility to conform with additions, modifications, or replacements of the Transmission System or MECL-Owned Interconnection Facilities. Customer may refer the issue of whether the Customer should be required to undertake such modifications at its expense for resolution pursuant to Section 13 of this Agreement in which case the Customer shall be bound by this provision until final resolution as provided under Section 13 and thereafter shall only be bound as provided for by such final resolution.

a. Notwithstanding Section 3.9.1, Section 3.9.4 or any other provision of the Agreement, the Customer shall only be required to provide MECL the data or information set forth in Sections B through H inclusive of Section V of Schedule B of the Agreement, as amended by Schedule K.

b. Section 3.13.1.3 of the Agreement is amended and restated in its entirety as follows:

"3.13.1.3 - If in the judgment of the System Operator, it is determined prior to the commencement of any planned outage that Customer's Generation is required to operate during planned maintenance, Customer will use commercially reasonable efforts to comply with such requests. Any compensation for must run generation, if any, will be pursuant to MECL business practices, as may be amended from time to time and in no event will MECL be liable for any such compensation, unless specifically required by approved business practices."

d. The reference in Section 5.6 of the Agreement to “two (2) business days” is replaced by “ten (10) business days”.

e. The reference in Section 5.6 of the Agreement to “Section 12” is replaced by “Section 13”.

f. Section 8.1a of the Agreement is amended to add “unless disputed in good faith” at the end of such Section 8.1a.

g. Section 8.1.2 is added to the Agreement and shall read as follows:

“Notwithstanding the foregoing, if an Event of Default has occurred and not been cured as provided above, prior to MECL exercising any remedies under Section 8.2.2(1), MECL must provide the Customer with a notice of intention to terminate the service. Customer shall then have a further 30 days (beyond that set forth in the first paragraph of Section 8.1) to cure such Event of Default or dispute MECL’s right to terminate the service by referring the matter for resolution under Section 13 in which case MECL may not terminate the service until the procedures in Section 13 are exhausted and then shall only be entitled to terminate if allowed to do so by the final resolution provided for under Section 13.”

5. ***Insurance***

a. Section 11.2 of the Agreement is amended to delete “Claims Made Coverage”.

b. Section 11.3 of the Agreement is amended and restated in its entirety as follows:

“**11.3 Notice of Cancellation -** Neither Party shall enter into a contract of insurance providing the coverage required in Schedule F unless the contract contains the following or equivalent clause: "No reduction or cancellation of the policy will be effective until thirty (30) days from the date written notice thereof is provided pursuant to Section 20.2 of the Agreement except ten (10) days notice for non-payment." Upon receipt of any notice of material change, reduction or cancellation, the Party will immediately notify the other Party in accordance with Section 20."

a. Section 11.6 of the Agreement is amended and restated in its entirety as follows:

"**11.6 Waiver of Subrogation -** Each Party, on its behalf and on behalf of its Affiliates, waives any right of subrogation under its respective insurance policies for any liability it has agreed to assume under this Agreement and that is covered by the policy. Evidence of this requirement will be noted on all certificates of insurance."

b. Section 1.0 of Schedule F of the Agreement is amended and restated in its entirety as follows:

"1.0 In Sections 1.01 to 1.03, each Party agrees and in addition in Section 1.04 Customer agrees, to provide and/or require its subcontractors to provide and maintain in full force and effect with insurance carriers duly licensed to carry on business in Prince Edward Island, the following insurance which shall be in effect as of the date of this agreement and shall remain in effect during the term hereof or any extension thereof or as otherwise specified herein:"

c. Section 1.01 of Schedule F of the Agreement is amended and restated in its entirety as follows:

"1.01 Workers Compensation as required by the Prince Edward Island Workers Compensation Act or similar applicable legislation covering all persons employed by the Parties or its subcontractors for work performed under this contract. For international employees, appropriate workers compensation liability insurance must be carried covering such employees of the Parties or its subcontractors for work performed under this contract."

d. Section 1.02 of Schedule F of the Agreement is amended and restated in its entirety as follows:

"1.02 Automobile Liability Insurance, covering all licensed motor vehicles owned, rented or leased and used in connection with the work to be performed under this agreement covering Bodily Injury and Property Damage Liability to a combined inclusive minimum limit of $2,000,000 initially, and increased to not less than $4,000,000 by the end of the twelfth year of the Term, which may consist of any combination of primary and excess policies, and mandatory Accident Benefits."

e. Section 1.03 of Schedule F of the Agreement is amended and restated in its entirety as follows:

"1.03 Commercial General Liability and Excess Liability Insurance on an occurrence basis in an amount not less than $5,000,000, which may consist of any combination of primary and excess policies, inclusive for both bodily injury, including death, personal injury and damage to property, including loss of use thereof, for each occurrence.

Coverage shall specifically include but not be limited to the following:

i. Blanket Contractual Liability;
ii. Products and Completed Operations
iii. Employer's Liability;
iv. Tenant's Legal Liability;
v. Non-Owned Automobile Liability; and,
vi. Broad Form Property Damage"

f. Section 1.04 of Schedule F of the Agreement is amended and restated in its entirety as follows:

"1.04 The Customer agrees to maintain "All Risk"" property insurance as applicable to a limit of the value of the full replacement cost of the facility any one occurrence covering physical loss or damage to Customer owned facilities."

g. Section 1.05 of Schedule F of the Agreement is amended and restated in its entirety as follows:

"1.05 Pollution Liability Insurance: The Customer will maintain a policy covering bodily injury and property damage claims, including cleanup costs as a result of sudden and accidental pollution conditions arising from Customer operations with limits of not less than $1,000,000 per occurrence, and such limit shall be reviewed as required by _____ and shall be adjusted upward, as necessary, in order to ensure that coverage appropriate to the legislative, regulatory, and potential claims of the day is maintained by ________________."

General Insurance Conditions

a. Certificates of Insurance:

i. Before starting work, Each Party shall provide the other with a certificate of insurance completed by a duly authorized representative of their insurer(s) certifying that at least the minimum coverages required here are in effect and that the coverages will not be cancelled, nonrenewed, or materially changed by endorsement or through issuance of other policy(ies) of insurance which restricts or reduces coverage, without 30 days advance written notice by registered mail, or courier, receipt required, to:

Maritime Electric Company, Limited
PO Box 1328, 180 Kent Street
Charlottetown PE C1A 7N2

OR

____

____

____

ii. Failure of either Party to demand such certificate or other evidence of full compliance with these insurance requirements or failure of either Party to identify a deficiency from evidence provided will not be construed as a waiver the obligation to maintain such insurance.

iii. The acceptance of delivery by either Party of any certificate of insurance evidencing the required coverages and limits does not constitute approval or agreement by that Party that the insurance requirements have been met or that the insurance policies shown in the certificates of insurance are in compliance with the requirements.

iv. If the Customer fails to maintain the insurance as set forth here, MECL will have the right, but not the obligation, to purchase said insurance at the Customer's expense. Alternatively, the Customer's failure to maintain the required insurance may result in termination of this contract at MECL's option.

a. Each Party shall be responsible for their own deductibles.

b. With the exception of clause 1.02 (Automobile Liability), all insurance noted above shall specify that it is primary coverage and not contributory with or in excess of any other insurance that may be maintained by the other Party.

c. All limits and deductibles are expressed in Canadian dollars.

d. Each Party shall request their respective insurers to endorse liability policies (excepting Worker's Compensation) with a waiver of subrogation in favor of the other Party.

e. Each Party shall request their respective insurers to add the other as Additional Insured to their respective Commercial General Liability and Excess Liability policies.

f. Coverages noted in 1.03 (Commercial General Liability and Excess Liability), and 1.06 (Pollution Liability) shall contain a Cross Liability clause and a Severability of Interests clause.

g. Contractor shall provide MECL with certified copies of insurance policies upon request.”

6. ***Arbitration; Representations and Warranties; Amendments.***

a. Section 14.2.3 of the Agreement is amended by adding “or will obtain” after “obtained” and adding “or will give” after “given”.

b. Section 26.3 of the Agreement is deleted.

c. Section 26.4 of the Agreement is amended and restated in its entirety as follows:

“**26.4 Amendment by Mutual Agreement -** Except as provided in Sections 26.1 and 26.2, this Agreement may only be amended, modified, or supplemented by written agreement signed by both MECL and Customer. Either Party may propose amendments to the Agreement provided that no such amendment shall become effective or binding upon the Parties until signed in writing by MECL and Customer; provided that if a Party considers that an amendment is required under any applicable law or regulation including any policy, rule or regulation enacted by IRAC under any statute and the other Party does not consider such amendment to be so required, then a Party may refer such matter for resolution under Section 13.”

d. Section 27.1 of the Agreement is amended and restated in its entirety as follows:

“This Agreement constitutes the entire understanding between the Parties, and supersedes any and all previous understandings, oral or written, which pertain to the subject matter contained herein or therein.”

e. Section 28.1 of the Agreement is amended to delete the words "of the MECL's Open Transmission" and substitute "of MECL's Open Access Transmission" and to delete "without making any necessary filings with IRAC to so amend the Agreement" and substitute therefore "except as provided herein."

7. ***Schedule B.***

a. The second paragraph of Section I.A.2 of Schedule B of the Agreement that begins "With regard to any interconnection costs or ongoing charges" is amended and restated in its entirety as follows: "With regard to any interconnection costs or ongoing charges, if there are any conflicts between this Agreement and the OATT, as may be amended from time to time, the OATT will govern, with the exception that this Agreement will prevail over Attachment J to the OATT."

b. Section II of Schedule B of the Agreement is amended to add the following prior to Section A and after the phrase "Maritime Electric Company, Limited standards": "provided that the Customer shall have the right to review Maritime Electric Company, Limited standards and in the event of disagreement with these standards shall have the right to refer the matter for resolution under Section 13."

c. Section II.J of Schedule B of the Agreement is amended to add the following prior to Section 1 and prior to the phrase beginning "These changes include, but are not limited to, the following:": "Each party shall use reasonable commercial efforts to make changes under this section that will have minimal impact on the other party's facility or system."

d. Section V of Schedule B of the Agreement is amended to add the following to the end of the introductory paragraph: "Should New Brunswick Transmission system Operator (NBTSO) or its successor, in its role as Reliability Coordinator and/or Balancing Authority for the Maritimes Area, require additional information and/or control from the Customer, other than what is stipulated in this Interconnection Agreement or in the Maritime Electric OATT, then those requirements will be deemed to be part of this Interconnection Agreement and must be supplied or provided by the Customer to MECL. Notwithstanding the previous sentence, Customer shall have the ability to contest NBTSO's right to require such additional information and/or control. MECL will provide the Customer with as much notice as practical of these requirements."

e. Sections B through H inclusive of Section V of Schedule B of the Agreement are replaced in their entirety with the following:

"**B. Normal SCADA Requirements**

Generators are required to install an RTU and shall provide for the following telemetry (the scan rates for all analog and digital data are 2 seconds).

1. Analog Data

- Substation Net Real Power Output (Megawatts)
- Substation Net Reactive Power Output (Megavars)
- Substation Output Voltage (Kilovolts)
- Maximum Allowable MW Output Setpoint

2. Digital Data (for Wind Facility)

- Substation Disconnect Status
- Substation Breaker Status
- Recloser Status

Customer and MECL will discuss the timing and methodology for collecting the following data:

- Substation Gross Hourly Energy Output (Megawatthours)
- Substation Net Hourly Energy Output (Megawatthours)
- Substation Net Hourly Energy Input (Megawatthours) (where required)

C. Automatic Facility Control - Telemetry

All units shall participate in Automatic Facility Control (AFC), and the AFC system shall have the following telemetry in addition to the SCADA requirements listed above.

1. AFC Status (on/off)
2. AFC setpoint (Megawatt limits)
3. Total VAR Output of Facility (MVARS)
4. Max available Capacitive VARS of Facility (MVARS)
5. Max available Inductive VARS of Facility (MVARS)

D. Automatic Set Point Control – Control Output

1. Voltage Set Point (kiloVolts)
2. Set point control of the Voltage Set point
3. Power Factor Set point (power factor)
4. Set point control of the Power Factor Set point
5. Setpoint Control Status

E. Automatic Facility Control – Parameters

The parameters outlined in Schedule H will be implemented during commissioning of the Distributed Wind Generators on AFC. Compliance with these parameters must be maintained.

F. Additional SCADA Requirements

MECL, at its discretion, may require miscellaneous trouble alarms (if any) associated with the distributed wind generators, such as:

1. Normal/Contingency mode status
2. Remote activation of Normal or Contingency mode by MECL

G. SCADA Communication Requirements

All Generation facilities are required to have 7 days-per-week, 24 hours-per-day response capability for all SCADA circuits. The Customer shall effect repairs within a reasonable period of time.

In the event that any SCADA data point is non-functional, MECL has the sole and exclusive right to take any action necessary to protect its system from real or perceived threats due to the lack of an operation wind facility SCADA including scaling back or disallowing any or all generation to operate until such time as the SCADA communications are fully restored.

H. Wind Farm Information

1. Wind speed (10 minute averaged)
2. Wind Direction. (10 minute average)
3. Air Temperature (10 minute averaged)
4. Number of Wind Turbine Generators in Pause Mode
5. Number of Wind Turbine Generators in Run Mode
6. Number of Wind Turbine Generators in Non-Communication

f. Section VI.D of Schedule B of the Agreement is amended and restated in its entirety as follows: "The Customer is not permitted to serve local distribution load while isolated from MECL because of the hazards of Islanding distributed wind facilities."

g. The third sentence of Section VII.D of Schedule B of the Agreement beginning "When MECL is working on the Facility" is amended and restated in its entirety as follows: "When MECL is working on the Facility, it is the Customer's responsibility to ensure the equipment being worked on is isolated and de-energized in compliance with the MECL Standard Protection Code provided to Customer. MECL will respect the Customer's own safety procedures; however, at a minimum, MECL's Standard Protection Code provided to Customer must be met."

h. The second and third sentences of Section VIII.A.2 of Schedule B of the Agreement are amended and restated in their entirety as follows: "This department must contact and schedule the work with the Customer prior to actually calibrating these meters. The department must not be unreasonably delayed by the Customer in scheduling the work. The Customer can observe this procedure if desired."

i. The seventh paragraph of Section VIII.E of Schedule B of the Agreement that reads "All outage schedules and maintenance work will be coordinated through MECL" is amended and restated in its entirety as follows: "All interconnection outage schedules and maintenance work will be coordinated through MECL."

j. The first sentence of Section VIII.F of Schedule B of the Agreement is amended and restated in its entirety as follows: "For facilities interconnected to the utility Transmission System, the Customer is required to meet North American Electric Reliability Corporation (NERC) Planning Standards where applicable."

k. The first sentence of Section VIII.G of Schedule B of the Agreement is amended and restated in its entirety as follows: "The following pages up to Schedule C contain technical data and other information as applicable respecting the ______________________ facility."

l. Customer shall comply with low voltage ride through, underfrequency ride through, and other requirements except as listed in Section 7(m) of Schedule K below, as set forth in the System Impact Study dated _______________.

8. ***Not Applicable Sections.***

a. All provisions in the Agreement relating to "blackstart", "droop", "excitation", "exciter", and "governor", and "power system stabilizers" are not applicable and deleted.

b. Section 4.2.2.5 of the Agreement is not applicable and deleted.

c. Sections I.B, I.E, I.F, I.G, II.A 3rd bullet, III.C.3, 2nd paragraph and III.K of Schedule B of the Agreement are not applicable and deleted.

d. Schedule D of the Agreement is not applicable and deleted.

e. Schedule E of the Agreement is not applicable and deleted.

f. Schedule I of the Agreement is not applicable and deleted.

[The remainder of this page is intentionally left blank.]

IN WITNESS WHEREOF the Parties have executed and delivered this Schedule K as of the Signing Date.

MARITIME ELECTRIC COMPANY, LIMITED

By: ____

Name:

By: ____

Name:

By: ____

Name:

ATTACHMENT K

Transmission System Planning

1.0 TRANSMISSION PLANNING PROCESS

The Transmission Provider's planning process will reflect the following nine principles:

Coordination - develop transmission plans with all customers and interconnected entities.

Openness - planning meetings will be open to all transmission and interconnection customers, government authorities, and other stakeholders.

Transparency - the basic methodology, criteria, and processes used to develop transmission plans and the status of upgrades identified in the transmission plan will be made available to stakeholders.

Information Exchange - Network Customers will be required to submit information on their projected loads and resources on a comparable basis.

Comparability – the transmission system plan will be developed for specific service requests comparable to native load.

Dispute Resolution – a process will be developed to manage disputes that arise from the planning process.

Regional Participation - coordinate with interconnected systems, share system plans, and identify system enhancements that could relieve congestion or integrate new resources.

Economic Planning Studies - account for economic, as well as reliability considerations.

Cost Allocation - requires that Transmission Providers address the allocation of costs of new facilities.

2.0 ROLES AND RESPONSIBILITIES

2.0.1 The Transmission Provider is responsible for planning and coordinating all changes to the Integrated Electrical System (the "IES"). In doing so, the Transmission Provider will maintain and ensure the adequacy and reliability of the IES.

2.0.2 The Transmission Provider is responsible to ensure that the transmission planning process allows for an efficient, non-discriminatory, coordinated, open and transparent forum open to all members of the Transmission System Users Group ("Users Group"). The transmission planning process will begin with and provide for input from the Users Group throughout. The Transmission Provider's process and its conduct shall be consistent with its Standards of Conduct.

2.0.3 The Transmission Provider will engage in regional planning activities through its participation in the Maine and Atlantic Technical Planning Committee ("MATPC").

3.0 DEFINITIONS (not included in the OATT)

3.1 10-Year Outlook

A report detailing system loads, generating resources and transmission projects that meets the needs identified in the baseline plan.

3.2 Baseline Plan

A plan reflecting committed and scheduled investments in transmission and generation facilities required to maintain the reliability of the IES.

3.3 Economic Planning Study

A study undertaken by the Transmission Provider with respect to economic upgrades such as congestion reduction or the integration of new resources.

3.4 Feasibility Review

An initial review undertaken by the Transmission Provider to determine if a request for a new or modified connection to the transmission system will require a System Impact Study.

3.5 NPCC

Northeast Power Coordinating Council

3.6 Point of Contact

The contact designated by the Transmission Provider to whom all information and inquiries related to the planning activities described in this Attachment K should be directed.

3.7 Public Policy Requirements

Requirements established by enacted Canadian federal or provincial statutes, acts or regulations.

4.0 TRANSMISSION SYSTEM PLANNING

4.1 Long-term Integrated Electricity System Development Plan

4.1.1 In each calendar year the Transmission Provider shall prepare and publish a plan for the development of the IES, referred to as the 10-Year Outlook. Each plan shall cover at least ten years, commencing on January 1 of the year following the year in which the plan is published.

4.1.2 Upon completion of the 10-Year Outlook, the Transmission Provider shall, at a minimum:

a. Publish the 10-Year Outlook on the Transmission Provider's public website;

b. Notify all members of the Users Group, via electronic mail;

c. In any publication or notice under paragraphs a) and b), solicit comments on the contents of the 10-Year Outlook via the Transmission Provider's public website;

d. Host a meeting of the Users Group for discussion of the 10-Year Outlook within 30 days of its publication;

e. Provide at least 7 days notice of the time and location of the Users Group meeting;

f. Reflect comments received within 45 days of the publication of the 10-Year Outlook in a published summary of comments on the Transmission Provider's public website;

g. Publish a revised 10-Year Outlook on the Transmission Provider's public website, if required to correct material errors or omissions and incorporate compelling requests for enhancements; and

h. Ensure that relevant comments are reflected in subsequent 10-Year Outlooks.

4.1.3 The 10-Year Outlook is generally comprised of:

a. The basic methodology, criteria, and processes used to develop transmission and generation plans;

b. The Baseline Plan as described in Section 4.2;

c. The summarized results of studies performed under Section 4.3;

d. The summarized results of other non-confidential studies of the Integrated Electricity System; and

e. The identification of upgrades as committed pending IRAC approval, under study, or proposed.

4.1.4 Nothing in this section shall prevent the Transmission Provider from preparing, in addition to the 10-Year Outlook, alternative plans based on differing assumptions as to the likelihood of implementation of the connection of new or modified Facilities to the IES.

4.1.5 Should a Users Group member feel that their comments on the 10-Year Outlook have not been adequately addressed by the Transmission Provider, they have the right to follow the dispute resolution process outlined in section 12 of the OATT.

4.2 Baseline Plan

4.2.1 The Transmission Provider shall prepare each Baseline Plan using:

a. Data and information submitted by Users Group members;
b. Information contained in Requests for Connection Assessment filed with the Transmission Provider under the Tariff;
c. The preceding year's Baseline Plan prepared under this section;
d. Data received from Transmitters that own or operate neighbouring transmission systems; and
e. Such other information as the Transmission Provider considers appropriate.

4.2.2 Each Baseline Plan shall reflect:

a. Committed and scheduled investments in Transmission Facilities, Generation Facilities and Transmission System expansion plans;
b. All connections of new or modified Facilities that have been approved by the Transmission Provider; and
c. All investments in Transmission and Generation Facilities required for reasons of Reliability of the IES.

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.

4.3 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

Connection Assessment. Requests for Transmission Service shall be processed in accordance with the OATT.

5.2.3 For modifications to Generation requests, the Connection Applicant shall submit to the Transmission Provider modifications to any information provided in the Request for Connection. The applicant shall retain its queue position if the modifications are in accordance with Sections 5.2.3.1, 5.2.3.2 or 5.2.3.4 or are determined not to be material modifications pursuant to Section 5.2.3.3.

5.2.3.1 Prior to the return of the executed System Impact Study Agreement to the Transmission Provider, modifications permitted under this Section shall include specifically: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project; (b) modifying the technical parameters associated with the Generating Facility technology or the Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

5.2.3.2 Prior to the return of the executed Facility Study Agreement to the Transmission Provider, the modifications permitted under this Section shall include specifically: (a) additional 15 percent decrease of electrical output (MW), and (b) Generating Facility technical parameters associated with modifications to Generating Facility technology and transformer impedances; provided, however, the incremental costs associated with those modifications are the responsibility of the requesting Generation Customer.

5.2.3.3 Prior to making any modification other than those specifically permitted by Sections 5.2.3.1, 5.2.3.2, and 5.2.3.4, the Generation Customer may first request that the Transmission Provider evaluate whether such modification is a material modification. In response to the Generation Customer's request, the Transmission Provider shall evaluate the proposed modifications prior to making them and inform the Generation

Customer in writing of whether the modifications would constitute a material modification. Any change to the Point of Interconnection, except those deemed acceptable under Section 5.2.3.1 or so allowed elsewhere, shall constitute a material modification. The Generation Customer may then withdraw the proposed modification or proceed with a new Request for Connection for such modification.

5.2.3.4 Extensions of less than three (3) cumulative years in the Commercial Operation Date of the Generating Facility to which the Request for Connection relates are not material and should be handled through construction sequencing.

5.2.4 Following receipt and review of a completed Request for Connection Assessment, the Transmission Provider will approve the request or conduct a Feasibility Review in respect of the connection of the new or modified facility where the Transmission Provider considers whether such connection:

a. May have an adverse impact on the Reliability of the IES; or

b. May create a probability of additional constraints by causing the IES to operate at or close to its normal operating limits.

5.2.5 Where the Transmission Provider concludes in its Feasibility Review that the connection of the new or modified Facility to the IES will not have either of the effects referred to in Sections 5.2.4(a) and 5.2.4(b), the Transmission Provider shall approve the request.

5.2.6 Where the Transmission Provider concludes in its Feasibility Review that the connection of a new or modified Facility to the IES will have an adverse impact on the Reliability of the IES in a Proximate Area only, the Transmission Provider shall:

a. Identify the upgrades to the elements of the IES in the Proximate Area that are required to mitigate the adverse impact of the connection of the new or modified Facility on the Reliability of the IES; and

b. Approve the connection of the new or modified Facility upon receipt of an undertaking by the Connection Applicant to pay its portion of the costs of such upgrades as assigned or allocated by the Transmission Provider in accordance with Section 5.6.

5.2.7 Where the Transmission Provider concludes in its Feasibility Review that the connection of the new or modified Facility to the IES may have (i) an adverse impact on the Reliability of the IES beyond a Proximate Area; or (ii) the effect referred to in Section 5.2.4(b), the Transmission Provider shall conduct a System Impact Study. Where the Transmission Provider conducts a System Impact Study and concludes that the connection of the new or modified Facility:

a. will have an adverse impact on the reliability of the IES, then the Transmission Provider shall not approve the connection unless the Connection Applicant agrees, in a form satisfactory to the Transmission Provider, to bear its portion of the costs of all upgrades to the IES that may be required to mitigate such adverse Reliability impact as assigned or allocated by the Transmission Provider in accordance with Section 5.6; or

b. if the Facility is a Generation Facility, will create the probability of additional constraints by causing the IES to operate at or close to its normal operating limits, then Transmission Provider shall not approve the connection unless:

i. where the Transmission Provider is satisfied that the imposition of conditions on the operation of the new or modified Facility can mitigate the probability of such additional constraints, the Connection Applicant agrees to include in its Generation Connection Agreement provisions that require the Connection Applicant to operate the new or modified Facility in accordance with those conditions; and

ii. in all other cases, the Connection Applicant agrees, in a form satisfactory to the Transmission Provider, to bear its portion of the costs of all upgrades to the IES that may be required to mitigate the probability of such additional constraints as assigned or allocated by the Transmission Provider in accordance with Section 5.6.

5.2.8 Where the Transmission Provider determines that it will not approve the connection of a new or modified Facility to the IES under section 5.2.6(a), the Connection Applicant may modify its connection proposal and request that the Transmission Provider conduct a new System Impact Study on the basis of the modified connection proposal. A change in Point-of-Receipt/Point-of-Delivery will be treated as a new proposal for queuing purposes, unless the Transmission Provider determines that the change is non-material.

5.3 General Connection Assessment Process for New or Modified Load Facilities

5.3.1 A person that wishes to connect a new or modified Load Facility to the IES shall file a Request for Connection Assessment with the Transmission Provider in the form set forth in Appendix K-1 Connection Assessment Procedure, together with the supporting material.

5.3.2 Relating to Section 5.3.1, for modified facilities, the Transmission Provider will advise the Connection Applicant if the modification may be materially impactive requiring such submission for preliminary review and, as necessary, an in-depth review.

5.3.3 Following receipt of a completed Request for Connection Assessment and subsequent preliminary review the Transmission Provider will either:

a. Approve the request; or

b. Conduct an in-depth review where the impact of such connection may have an adverse impact on the Reliability of the IES.

5.3.4 Where the Transmission Provider concludes that the connection of the new or modified Facility does not have adverse impact on the IES the Transmission Provider will approve the request. Otherwise the Transmission Provider shall:

a. Identify the upgrades to the elements of the IES that are required to mitigate the adverse impact of the connection of the new or modified Facility on the Reliability of the IES; and

b. Approve the connection of the new or modified Facility upon receipt of an undertaking by the Connection Applicant to pay its portion of the costs of such upgrades in accordance with Section 5.6.

5.3.5 Where the Transmission Provider, in consultation with the Connection Applicant, determines that such a connection is not practical the Connection Applicant may modify its connection proposal and request that the Transmission Provider conduct a new review on the basis of the modified connection proposal. A modified connection proposal will be treated as a new request for queuing purposes.

5.4 Costs of Connection Assessments

5.4.1 The Transmission Provider shall invoice a Connection Applicant for the costs incurred by the Transmission Provider in conducting a Feasibility Review in respect of the Connection Applicant's Request for Connection Assessment, less the amount paid by the Connection Applicant as a deposit.

5.4.2 The Transmission Provider shall invoice a Connection Applicant for:

a. the costs incurred by the Transmission Provider in conducting a System Impact Study in respect of the Connection Applicant's Request for Connection Assessment, less the amount paid by the Connection Applicant as a deposit where the System Impact Study relates solely to such Request for Connection Assessment; or

b. for the Connection Applicant's share of the costs incurred by the Transmission Provider in conducting a System Impact Study in respect of the Connection Applicant's Request for Connection Assessment, less the amount paid by the Connection Applicant as a deposit, where the System Impact Study relates to such Request for Connection Assessment and to one or more other Requests for Connection Assessment. Such share shall be determined by the Transmission Provider.

5.4.3 An invoice referred to in Section 5.3.1 or 5.3.2, shall be payable in full by the Connection Applicant within 20 Business Days of the date of the invoice. For greater certainty, such invoice shall be considered to create an obligation to pay the amount stated in the invoice and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

5.4.4 The principles of cost sharing as described in the section 5.6, Costs of Connection, shall also apply to the Connection Assessment Costs.

5.5 Implementation of Connection

5.5.1 Each Connection Applicant shall ensure that the connection of its new or modified Facility is effected in a manner that does not represent a material change from:

a. any technical requirements that are identified in the applicable Connection Assessment as being required to be met in respect of the connection of the new or modified Facility;

or

b. the configuration or technical parameters that were used by the Transmission Provider as the basis upon which it approved such connection or that were imposed as a condition in approval of such connection, unless the Connection Applicant has obtained the prior approval of the Transmission Provider for the material change.

5.5.2 The Transmission Provider shall approve a material change referred to in Section 5.5.1 unless it determines that such deviation will have an adverse effect on the reliability of the IES. Where the Transmission Provider does not approve such a material change, the Connection Applicant may propose to the Transmission Provider measures designed to mitigate the adverse effects of the material change on the Reliability of the IES.

5.6 Costs of Connection

5.6.1 This policy pertains to situations where a request (or requests) for point-to-point or network service requires a transmission network upgrade. This policy in no way diminishes the requirement for the costs of direct assignment facilities to be borne by the Transmission Customer.

5.6.2 The Transmission Provider is not obligated to expand the transmission system based on the results of Economic Planning Studies.

5.6.3 For any project for which costs would not be recovered entirely through the Transmission Provider's rates, i.e. regional projects, cost allocation would be subject to review by IRAC.

5.6.4 The principles for cost sharing in this situation are as follows:

a. The Transmission Provider will recover the costs of projects required for meeting service requests and system improvements in accordance with the provisions of the OATT.

b. If the additional transmission tariff revenues associated with the increased use of the Transmission System is more than or equal to the increase in the Transmission System revenue requirement there will be no costs incurred by the Transmission Customer.

c. If the additional transmission tariff revenues associated with the increased use of the Transmission System are less than the increase in the Transmission System revenue requirement, the Transmission Customer will make a contribution to capital of an amount that will allow the Transmission Provider to continue to collect the full revenue requirement.

d. To the extent that the Transmission Provider identifies system benefits, the requirement of the Transmission Customer to make a contribution to capital is diminished by the net present value of the system benefits.

e. If multiple service requests will benefit from a system upgrade, the cost sharing among the Interested Parties will be based on a load flow study. The study will identify the relative usage of the upgraded facilities by the transactions on a 12CP basis and the Transmission Provider will allocate the costs in proportion to the relative usage.

f. To the extent that an upgrade to meet a request for service leads to an advancement in the schedule of network upgrades for general system benefits to which the Transmission Provider has made a commitment in its transmission expansion plan, the Transmission Customer will pay only the costs of the advancement.

5.6.5 For new loads, the Transmission Customer pays only the OATT rate unless the carrying charges of the new facilities are higher than the payments that will be made by the new load as part of the tariff. The Transmission Customer will pay the tariff rates and a contribution to capital equal to the incremental carrying charges if the new connection costs exceed the average rolled-in costs of facilities.

5.6.6 A Transmission Customer which has paid a contribution to capital will be eligible for a proportional refund in the event of a subsequent Transmission Customer connection within the first 7 years of transmission asset commissioning. Refunds are non-interest bearing. The contribution from the new customer and the refund to the incumbent will be calculated on a pro rata basis in proportion to the segment of the transmission assets that are used by each customer and in proportion to the capacity of the transmission assets used by each customer relative to the economic life of the transmission assets. The contribution from the new customer will be reduced by credits that arise from consequential new revenues in accordance with Section 5.6.5, and the Transmission Provider will refund the incumbent by the amount of that reduction.

5.7 Industrial Expansion System Bypass Policy

5.7.1 This policy pertains to situations where a customer proposes to serve new load using new on-site generation by wheeling through the local portion of the Transmission System. This policy sets the principles for the case where the construction of on-site transmission or distribution facilities by the customer would be less expensive to the customer than paying the transmission tariff rates for wheeling through the local portion of the Transmission System.

5.7.2 In some situations the incremental cost to the Transmitter of allowing the customer to use the Transmission System is less than the cost of the proposed on-site transmission or distribution facilities. In this case, having the customer use the Transmission System reduces the overall cost. The resulting savings will be split evenly between the Transmission Customer and the revenue collected by the Transmission Provider.

5.7.3 When the incremental cost to the Transmitter of allowing the transmission customer to use the Transmission System is greater than the cost of the proposed on-site transmission or distribution facilities, it is appropriate for the customer to build the proposed on-site transmission or distribution facilities.

5.7.4 If it would be more expensive for the Transmission Customer to build on-site transmission or distribution facilities than to pay the transmission tariff rates for wheeling through the local portion of the Transmission System, it is presumed that the customer will choose the least expensive option.

5.7.5 If the Transmission Customer's use of the local portion of the Transmission System results in a requirement to upgrade that portion of the system, the Transmission Customer will be required to pay for the upgrade.

Appendix K-1

Connection Assessment Process

PURPOSE

To set out the process by which Transmitters, Distributors, Transmission Users, or other persons may request the Transmission Provider to undertake assessments of connection to the Integrated Electricity System of new or materially modified Facilities.

SCOPE AND APPLICATION

This procedure is applicable to all prospective and actual Connection Applicants. A Connection Applicant may or may not be a Transmission User at the time of Connection Assessment, but will be required to complete the necessary agreements prior to the actual connection of any facility or the provision of service. This procedure is applicable in the case of all new or modified connections to the Integrated Electricity System. A Facility connection is considered to be materially modified if:

- A transformer is changed,
- A distribution feeder is added, or its breaker rating upgraded,
- Protection is changed, including breaker ratings or settings,
- Switchyard configuration changes such as electrical relocation of switches or breakers,
- Capacitors are added or removed,
- Load increase exceeding 1 MW,
- Generation is added, including embedded generation over 1 MW, or
- Other parameters of the connection or the facility connected are altered in a way that may impact the Integrated Electricity System.

CONNECTION APPLICANT RESPONSIBILITIES

It is the responsibility of each prospective or actual Connection Applicant to:

- Request the Transmission Provider to conduct a Feasibility Review using Forms K-01 or K-02, and make applications and execute contracts as required in the OATT for System Impact Studies and Facilities Studies;
- Pay deposits and invoiced fees;
- Undertake all design of any connection proposal and to provide the requisite information to the Transmission Provider;
- Respond promptly to any queries or additional information requests;
- Secure all other authorizations required; and
- Proceed with subsequent stages and to implementation within the prescribed timelines in order to maintain queue position.

CONFIDENTIALITY

Public Items

- List of System Impact Study requests and applications received (Connection Applicant, date of receipt of complete application, brief description, connection location), together with ongoing status updates and Connection Application date stamp.
- System Impact Study Reports (excluding report appendices containing Confidential Information).

Confidential Items

- Feasibility Reviews (requests, existence, and reports)
- Needs Assessments
- Connection Applications and supporting information (but not the existence of the application or the reports thereon)
- Appendices to System Impact Study Reports containing Confidential Information
- Facilities Study Reports
- Study costs and payments

FEASIBILITY REVIEW

Feasibility Review includes a determination of needs and provides an opportunity for early identification of:

- Any problems with the proposed Facility design,
- All grid-related information needed by the Connection Applicant to design the Facility connection, and all information required by the Transmission Provider to complete the System Impact Study, and
- Any likely non-standard design requirements for the new or modified Facility.

Feasibility review is mandatory with respect to new or modified Facility connections, but not with respect to Point to Point Service requests.

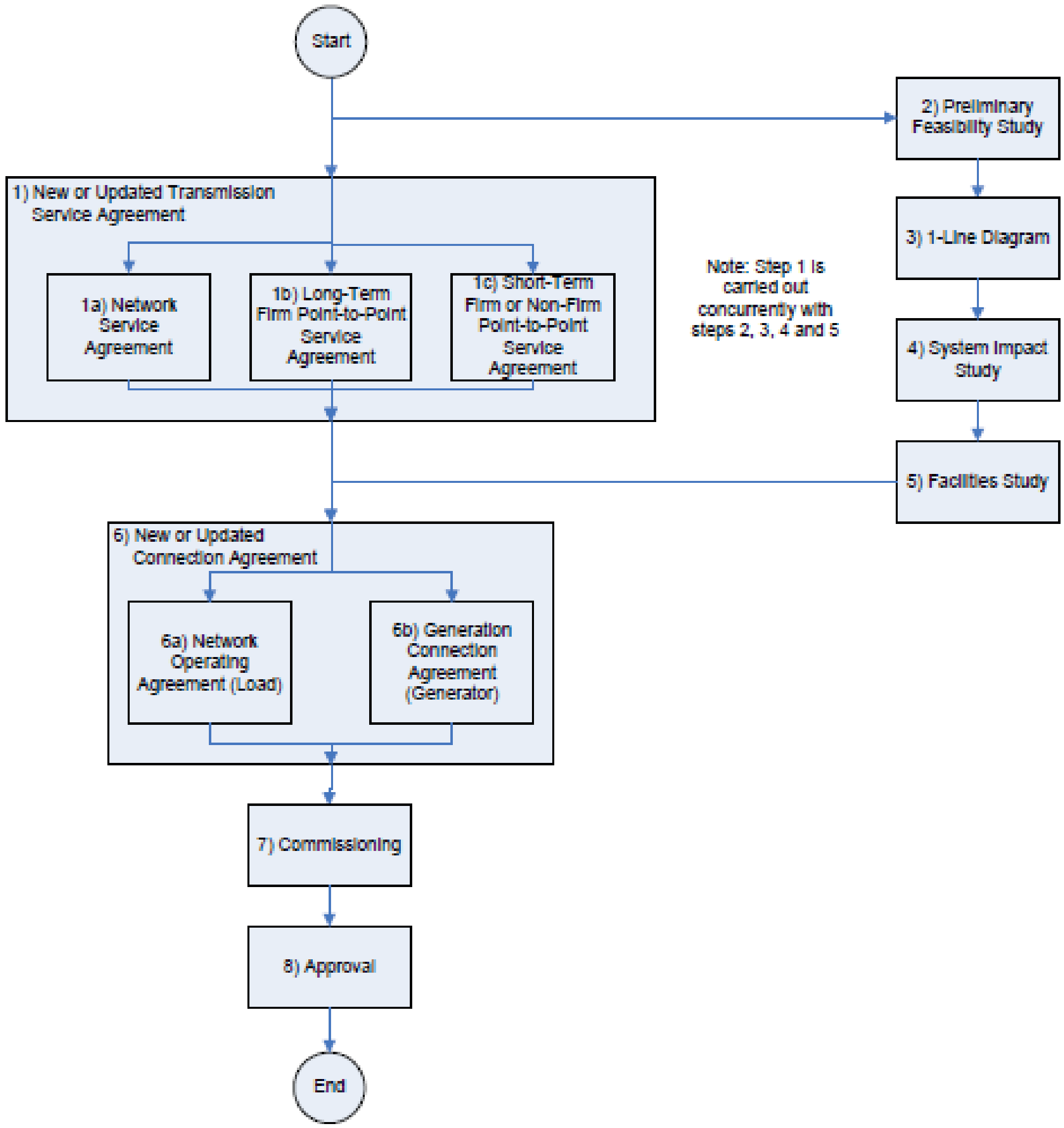
DETERMINATION OF NEEDS

- The Transmission Provider will determine what assessments and studies are or may be needed in order to complete a particular System Impact Study.
- The Transmission Provider will estimate the cost and time requirements of such assessments and studies.
- The Transmission Provider may determine that it will (on application) be able to issue a Connection Approval without a System Impact Study. If so, the Connection Applicant is still required to submit a complete application for a Facilities Study in order to secure the Transmission Provider's approval of the new or modified facility connection, and in order to secure the "date stamp", a basis for prioritization and cost allocation.

SYSTEM IMPACT AND FACILITY STUDIES

System Impact Studies and Facilities Studies will be processed as set out in the OATT (Section 19 for Point-to-Point Requests and Section 32 for Network Service Requests).

PROCESS FOR CONNECTION OF NEW OR MODIFIED FACILITIES



Connection Applicant Form (K-01)
Application for Feasibility Review for Generation and/or Load

Date: ______________________________

Proponent: ______________________________
____
____
____

Project Description:

Type	**(CT, Wind Farm, Load, etc.)**
Size (MW)	
Voltage (kV)	
Location	
Longitude	
Latitude	
Map Datum	
PID	

Transmission System Connection:

Line Number	
Voltage (kV)	
Distance from Project (km)	

Transmission Services Requested:

Service	Point-to-Point or Network
Customer	
Expected in-service date	

Name: ______________________

Title: ______________________

Signature ______________________

Connection Applicant Form (K-02)

Application for Feasibility Review for Transmission Lines or Substations

1. Applicant ______________________________ Date ______________________

2. General Description of Project:

____

____

____

3. Type of Facility __________________________ In-Service Date ______________

4. Transmission Line or Substations

   a. From __________________________ To __________________________
   (Terminal – Name - Location) (Terminal – Name – Location)

   b. Third terminal or tap (if any) ____

   c. Distance ___________ km Voltage _________ kV

   Conductor size _______________

   d. Type of line relaying: Backup relaying

   Breaker Failure

   SPS

5. Transformer Rating

MVA	_______	
HV	_______	kV
LV	_______	kV
Tertiary	_______	kV

Resistance ______________ Reactance _______________

6. Attach simplified one-line diagram of transmission/substation with breaker configuration.

7. List Facility Ratings

8. Reliability Studies completed (if required)

Short Circuit ______________________________

Load Flow ______________________________

Stability ______________________________

ATTACHMENT L

Standards of Conduct

The Standards of Conduct have been removed from the OATT and the IRAC approved version is posted separately on the Transmission Providers web site.

ATTACHMENT M

Special Conditions

None

ATTACHMENT N

(Not Used)

ATTACHMENT O

Creditworthiness Procedures & Security Deposit Requirements

1.0 Introduction

These Creditworthiness Procedures outline the Transmission Provider's process for determining a Transmission Customer's ability to meet its obligations under the Maritime Electric OATT. All customers are required to provide a security deposit prior to taking service under the Tariff.

2.0 Credit Review

A credit review and credit limit approval process is required for all Transmission Customers prior to the execution of a Service Agreement. For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service under the Maritime Electric OATT, the Transmission Provider will require reasonable credit review procedures. This review shall initially be conducted for each Transmission Customer and shall be reviewed periodically, including upon reasonable request by the Transmission Customer.

3.0 Creditworthiness

A Transmission Customer is creditworthy if they meet the Creditworthiness Criteria outlined in this Attachment O. Specifically, the Transmission Customer must be deemed to be a low risk.

4.0 Creditworthiness Criteria

Transmission Customers shall be evaluated on a scale of 1 to 10. A creditworthiness rating of 1 to 5 is considered low risk whereas a rating of 6 to 8 is considered medium risk and a rating of 9 or 10 is considered high risk. When available, the Transmission Provider shall use a formal credit rating from a recognized credit rating agency such as Standard & Poor's (S&P), Moody's, Fitch or Dominion Bond Rating Service (DBRS). When more than one rating is available, the lower rating shall be used in the assessment.

When a credit rating is not available from a recognized credit rating agency, a substitute ratings process will be used to develop a rating that is equivalent to the external ratings scale. Such ratings will be compiled by analyzing key financial metrics and benchmarking the results against the metrics used by external credit rating agencies in their rating process. If financial information cannot be obtained, the internal rating for that counterparty will default to the lowest rating.

Table 1
Maritime Electric Creditworthiness Rating

Maritime Electric Rating	Equivalent S&P/Fitch Rating	Equivalent Moody's Rating	Equivalent DBRS Rating	Overall Risk	Maximum Credit Limit (000 Dollars)
1	AA+ and above	Aa1 and above	AAH and above	Low	$50,000
2	AA	Aa2	AA	Low	$45,000
3	AA-	Aa3	AAL	Low	$40,000
4	A+	A1	AH	Low	$35,000
5	A	A2	A	Low	$25,000
6	A-	A3	AL	Medium	$20,000
7	BBB+	Baa1	BBBH	Medium	$15,000
8	BBB	Baa2	BBB	Medium	$10,000
9	BBB-	Baa3	BBBL	High	$5,000
10	Below BBB- and unrated	Below Baa3 and unrated	Below BBBL and unrated	High	

Credit limits may be extended above the initial maximum credit limits by posting collateral. Acceptable forms of collateral are: Cash deposits, Irrevocable Letters of Credit, and Financial Guarantees.

5.0 Changes in Creditworthiness Status

The Creditworthiness of Transmission Customers will be reviewed periodically. If the review results in a change to a Transmission Customer's Creditworthiness Status, the customer will be notified immediately. This notification will include the reason(s) for the change and will identify the new collateral requirement(s). The new requirements must be met within five (5) business days.

If the Transmission Customer disagrees with the Transmission Provider's determination of the Transmission Customer's Creditworthiness or collateral requirements, the Transmission Customer may write to the Transmission Provider explaining the nature of the disagreement. The Transmission Provider will respond to such a letter within five (5) Business Days.

6.0 Security Deposit Requirements for Reserving Transmission Service

The security deposit may be in the form of a letter of credit, parental guarantee, cash, or an alternate form of security proposed by the customer and accepted by, at the sole discretion, of Maritime Electric. The deposit shall be in an amount equal to:

- Two months of charges for transmission service, including Schedules 1 and 2; or
- The full charge for transmission service for service requests less than two months.

ATTACHMENT P
OASIS Terms and Conditions

1. Open Access Same-Time Information Systems

1.1 Obligations of Transmission Providers and Responsible Parties.

a. MECL will provide for the operation of an OASIS, either individually or jointly with other Transmission Providers, in accordance with the requirements of this Attachment. The Transmission Provider may delegate this responsibility to an entity such as another Transmission Provider, an Independent System Operator, a Regional Transmission Group, or a Regional Reliability Council (a “Responsible Party”).

b. A Responsible Party must provide access to an OASIS providing standardized information relevant to the availability of transmission capacity, prices, and other information (as described in this part) pertaining to the transmission system for which it is responsible.

c. A Responsible Party may not deny or restrict access to an OASIS user merely because that user makes automated computer-to-computer file transfers or queries, or extensive requests for data.

d. In the event that an OASIS user's grossly inefficient method of accessing an OASIS node or obtaining information from the node seriously degrades the performance of the node, a Responsible Party may limit a user's access to the OASIS node without prior IRAC approval. The Responsible Party must immediately contact the OASIS user to resolve the problem. Notification of the restriction must be made to IRAC within two business days of the incident and include a description of the problem. A closure report describing how the problem was resolved must be filed with IRAC within one week of the incident.

e. In the event that an OASIS user makes an error in a query, the Responsible Party can block the affected query and notify the user of the nature of the error. The OASIS user must correct the error before making any additional queries. If there is a dispute over whether an error has occurred, the procedures in paragraph (d) of this section apply.

f. Transmission Providers must provide "read only" access to the OASIS to IRAC staff, at no cost, after such staff members have complied with the requisite registration procedures.

1.2 Information to be posted on the OASIS.

a. The information posted on the OASIS must be in such detail and the OASIS must have such capabilities as to allow Transmission Customers to:

1. Make requests for transmission services offered by Transmission Providers, Resellers and other providers of ancillary services, request the designation of a network resource, and request the termination of the designation of a network resource;

2. View and download in standard formats, using standard protocols, information regarding the transmission system necessary to enable prudent business decision making;

3. Post, view, upload and download information regarding available products and desired services;

4. Clearly identify the degree to which transmission service requests or schedules were denied or interrupted;

5. Obtain access, in electronic format, to information to support available transmission capability calculations and historical transmission service requests and schedules for various audit purposes; and

6. Make file transfers and automated computer-to-computer file transfers and queries as defined by the Open Access Same-Time Information Systems (OASIS) Standards and Communications Protocols referenced in section 2.1 herein.

b. Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

1. Definitions. For purposes of this section the terms listed below have the following meanings:

i. Posted path means any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted.

ii. Constrained posted path means any posted path having an ATC less than or equal to 25 percent of TTC at any time during the preceding 168 hours or for which ATC has been calculated to be less than or equal to 25 percent of TTC for any period during the current hour or the next 168 hours.

iii. Unconstrained posted path means any posted path not determined to be a constrained posted path.

iv. The word interconnection, as used in the definition of "posted path", means all facilities connecting two adjacent systems or control areas.

v. Available transfer capability or ATC means the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses, or such definition as contained in Control Area Operator approved reliability standards.

vi. Total transfer capability or TTC means the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Control Area Operator approved reliability standards.

vii. Capacity Benefit Margin or CBM means the amount of TTC preserved by the Transmission Provider for load-serving entities, whose loads are located on that Transmission Provider's system, to enable access by the load-serving entities to generation from interconnected systems to meet generation reliability requirements, or such definition as contained in Control Area Operator approved reliability standards.

viii. Transmission Reliability Margin or TRM means the amount of TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure, or such definition as contained in Control Area Operator approved reliability standards.

2. Calculation methods, availability of information, and requests.

   i. Information used to calculate any posting of ATC and TTC must be dated and time-stamped and all calculations shall be performed according to consistently applied methodologies referenced in the Transmission Provider's transmission tariff and shall be based on Board-approved reliability standards as well as current industry practices, standards and criteria.

   ii. On request, the Responsible Party must make all data used to calculate ATC, TTC, CBM, and TRM for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (e.g., thermal, voltage, stability), as well as load forecast assumptions) in electronic form within one week of the posting. The information is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. This information is to be retained for six months after the applicable posting period.

   iii. System planning studies, facilities studies, and specific network impact studies performed for customers or the Transmission Provider's own network resources are to be made publicly available in electronic form on request and a list of such studies shall be posted on the OASIS. A study is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. These studies are to be retained for five years.

3. Posting. The ATC, TTC, CBM, and TRM for all Posted Paths must be posted in megawatts by specific direction and in the manner prescribed in this subsection.

i. Constrained posted paths -

A. For firm ATC and TTC.

1. The posting shall show ATC, TTC, CBM, and TRM for a 30-day period. For this period postings shall be: by the hour, for the current hour and the 168 hours next following; and thereafter, by the day. If the Transmission Provider charges separately for on -peak and off-peak periods in its tariff, ATC, TTC, CBM, and TRM will be posted daily for each period.

2. Postings shall also be made by the month, showing for the current month and the 12 months next following.

3. If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following to the end of the planning horizon but not to exceed 10 years.

B. For non-firm ATC and TTC. The posting shall show ATC, TTC, CBM and TRM for a 30-day period by the hour and days prescribed under paragraph (b)(3)(i)(A)(1) of this section and, if so requested, by the month and year as prescribed under paragraph (b)(3)(i)(A) (2) and (3) of this section. The posting of non-firm ATC and TTC shall show CBM as zero.

C. Updating posted information for constrained paths.

1. The capability posted under paragraphs (b)(3)(i)(A) and (B) of this section must be updated when transactions are reserved or service ends or whenever the estimate for the path changes by more than 10 percent.

2. All updating of hourly information shall be made on the hour.

3. When the monthly and yearly capability posted under paragraphs (b)(3)(i)(A) and (B) of this section are updated because of a change in TTC by more than 10 percent, the Transmission Provider shall post a brief, but specific, narrative explanation of the reason for the update. This narrative should include, the specific events which gave rise to the update (e.g., scheduling of planned outages and occurrence of forced transmission outages, de-ratings of transmission facilities, scheduling of planned generation outages and occurrence of forced generation outages, changes in load forecast, changes in new facilities' in-service dates, or other events or assumption changes) and new values for ATC on the path (as opposed to all points on the network).

4. When the monthly and yearly capability posted under paragraphs (b)(3)(i)(A) and (B) of this section remain unchanged at a value of zero for a period of six months, the Transmission Provider shall post a brief, but specific, narrative explanation of the reason for the unavailability of ATC.

ii. Unconstrained posted paths.

A. Postings of firm and nonfirm ATC, TTC, CBM, and TRM shall be posted separately by the day, showing for the current day and the next six days following and thereafter, by the month for the 12 months next following. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC, TTC, CBM, and TRM will be posted separately for the current day and the next six days following for each period. These postings are to be updated whenever the ATC changes by more than 20 percent of the Path's TTC.

B. If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following until the end of the planning horizon but not to exceed 10 years.

iii. Calculation of CBM.

A. The Transmission Provider must re-evaluate its CBM needs at least every year.

B. The Transmission Provider must post its practices for re-evaluating its CBM needs.

ii. Daily load. The Transmission Provider must post on a daily basis, its load forecast, including underlying assumptions, and actual daily peak load for the prior day.

c. Posting Transmission Service Products and Prices.

1. Transmission Providers must post prices and a summary of the terms and conditions associated with all transmission products offered to Transmission Customers.

2. Transmission Providers must provide a downloadable file of their complete tariffs in the same electronic format as the tariff that is filed with IRAC. Transmission Providers also must provide a link to all of the rules, standards and practices that relate to transmission services posted on the Transmission Providers' public Web sites.

3. Any offer of a discount for any transmission service made by the Transmission Provider must be announced to all potential customers by posting on the OASIS.

4. For any transaction for transmission service agreed to by the Transmission Provider and a customer, the Transmission Provider (at the time when ATC must be adjusted in response to the transaction), must post on the OASIS (and make available for download) information describing the transaction (including: price; quantity; points of receipt and delivery; length and type of service; identification of whether the transaction involves the Transmission Provider's wholesale merchant function or any affiliate; identification of what, if any, ancillary service transactions are associated with this transmission service transaction; and any other relevant terms and conditions) and shall keep such information posted on the OASIS for at least 30 days. A record of the transaction must be retained and kept available as part of an audit log.

5. Customers choosing to use the OASIS to offer for resale transmission capacity they have purchased must post relevant information to the same OASIS as used by the Transmission Provider from whom the Reseller purchased the transmission

capacity. This information must be posted on the same display page, using the same tables, as similar capability being sold by the Transmission Provider, and the information must be contained in the same downloadable files as the Transmission Provider's own available capability.

d. Posting Ancillary Service Offerings and Prices.

1. Any ancillary service offered under the MECL OATT must be posted with the price of that service.

2. Any offer of a discount for any ancillary service made by the Transmission Provider must be announced to all potential customers solely by posting on the OASIS.

3. For any transaction for ancillary service agreed to by the Transmission Provider and a customer, the Transmission Provider (at the time when ATC must be adjusted in response to an associated transmission service transaction, if any), must post on the OASIS (and make available for download) information describing the transaction (including: date and time when the agreement was entered into; price; quantity; length and type of service; identification of whether the transaction involves the Transmission Provider's wholesale merchant function or any affiliate; identification of what, if any, transmission service transactions are associated with this ancillary service transaction; and any other relevant terms and conditions) and shall keep such information posted on the OASIS for at least 30 days. A record of the transaction must be retained and kept available as part of an audit log.

4. Any other interconnected operations service offered by the Transmission Provider may be posted, with the price for that service.

5. Any entity offering an ancillary service shall have the right to post the offering of that service on the OASIS if the service is one offered by the Transmission Provider under the MECL OATT. Any entity may also post any other interconnected operations service voluntarily offered by the Transmission Provider. Postings by customers and third parties must be on the same page, and in the same format, as postings of the Transmission Provider.

e. Posting specific transmission and ancillary service requests and responses -

1. General rules.

i. All requests for transmission and ancillary service offered by Transmission Providers under the MECL OATT, including requests for discounts, and all requests to designate or terminate a network resource, must be made on the OASIS and posted prior to the Transmission Provider responding to the request, except as discussed in paragraphs (e)(1)(ii) and (iii) of this section. The Transmission Provider must post all requests for transmission service, for ancillary service, and for the designation or termination of a network resource comparably. Requests for transmission service, ancillary service, and to designate and terminate a network resource, as well as the responses to such requests, must be conducted in accordance with the Transmission Provider's tariff.

ii. The requirement in paragraph (e)(1)(i) of this section, to post requests for transmission and ancillary service offered by Transmission Providers under the MECL OATT, including requests for discounts, prior to the Transmission Provider responding to the request, does not apply to requests for next hour service made during Phase I.

iii. In the event that a discount is being requested for ancillary services that are not in support of basic transmission service provided by the Transmission Provider, such request need not be posted on the OASIS.

iv. In processing a request for transmission or ancillary service, the Responsible Party shall post the same information as required in paragraphs (c)(4) and (d)(3) of this section, and the following information: the date and time when the request is made, its place in any queue, the status of that request, and the result (accepted, denied, withdrawn). In processing a request to designate or terminate the designation of a network resource, the Responsible Party shall post the date and time when the request is made.

v. For any request to designate or terminate a network resource, the Transmission Provider (at the time when the request is received), must post on the OASIS (and make available for download) information describing the request (including: name of requestor, identification of the resource, effective time for the designation or termination, identification of whether the transaction involves the Transmission Provider's wholesale merchant function or any affiliate; and any other relevant terms and conditions) and shall keep such information posted on the OASIS for at least 30 days. A record of the transaction must be retained and kept available as part of an audit log.

vi. The Transmission Provider shall post a list of its current designated network resources and all network customers' current designated network resources on OASIS. The list of network resources should include the name of the resource, its geographic and electrical location, its total installed capacity, and the amount of capacity to be designated as a network resource.

2. Posting when a request for transmission service is denied.

   i. When a request for service is denied, the Responsible Party must provide the reason for that denial as part of any response to the request.

   ii. Information to support the reason for the denial, including the operating status of relevant facilities, must be maintained for five years and provided, upon request, to the potential Transmission Customer and the Commission's Staff.

   iii. Any offer to adjust operation of the Transmission Provider's System to accommodate the denied request must be posted and made available to all Transmission Customers at the same time.

3. Posting when a transaction is curtailed or interrupted.

   i. When any transaction is curtailed or interrupted, the Transmission Provider must post notice of the curtailment or interruption on the OASIS, and the Transmission Provider must state on the OASIS the reason why the transaction could not be continued or completed.

   ii. Information to support any such curtailment or interruption, including the operating status of the facilities involved in the constraint or interruption, must be maintained and made available upon request, to the curtailed or interrupted customer, IRAC and any other person who requests it, for five years.

   iii. Any offer to adjust the operation of the Transmission Provider's system to restore a curtailed or interrupted transaction must be posted and made available to all curtailed and interrupted Transmission Customers at the same time.

f. Posting Transmission Service Schedules Information. Information on transmission service schedules must be recorded by the entity scheduling the transmission service and must be available on the OASIS for download. Transmission service schedules must be posted no later than seven calendar days from the start of the transmission service.

g. Posting Other Transmission-Related Communications.

1. The posting of other communications related to transmission services must be provided for by the Responsible Party. These communications may include “want ads” and “other communications” (such as using the OASIS as a Transmission related conference space or to provide transmission-related messaging services between OASIS users). Such postings carry no obligation to respond on the part of any market participant.

2. The Responsible Party is responsible for posting other transmission-related communications in conformance with the instructions provided by the third party on whose behalf the communication is posted. It is the responsibility of the third party requesting such a posting to ensure the accuracy of the information to be posted.

3. Notices of transfers of personnel shall be posted as described in the Transmission Provider’s standards of conduct. The posting requirements are the same as those provided in Section 1.3 herein for audit data postings.

4. Logs detailing the circumstances and manner in which a Transmission Provider or Responsible Party exercised its discretion under any terms of the tariff shall be

posted. The posting requirements are the same as those provided in Section 1.3 herein for audit data postings.

h. Posting information summarizing the time to complete transmission service request studies.

1. For each calendar quarter, the Responsible Party must post the set of measures detailed in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section related to the Responsible Party's processing of transmission service request system impact studies and facilities studies. The Responsible Party must calculate and post the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section for requests for short-term firm point-to-point transmission service, requests for long-term firm point-to-point transmission service, and requests to designate a new network resource or network load. When calculating the measures in paragraph (h)(1)(i) through paragraph (h)(1)(iv) of this section, the Responsible Party may aggregate requests for short-term firm point-to-point service and requests for long-term firm point-to-point service, but must calculate and post measures separately for transmission service requests from Affiliates and transmission service requests from Transmission Customers who are not Affiliates. The Responsible Party is required to include in the calculations of the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section all studies the Responsible Party conducts of transmission service requests on another Transmission Provider's OASIS.

i. Process time from initial service request to offer of system impact study agreement.

A. Number of new system impact study agreements delivered during the reporting quarter to entities that request transmission service,

B. Number of new system impact study agreements delivered during the reporting quarter to entities that request transmission service more than thirty (30) days after the Responsible Party received the request for transmission service,

C. Mean time (in days), for all requests acted on by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the request for transmission service to when the Responsible Party changed the transmission service request status to indicate that the Responsible Party could offer transmission service or needed to perform a system impact study,

D. Mean time (in days), for all system impact study agreements delivered by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the request for transmission service to the date when the Responsible Party delivered a system impact study agreement, and

E. Number of new system impact study agreements executed during the reporting quarter.

ii. System impact study processing time.

A. Number of system impact studies completed by the Responsible Party during the reporting quarter,

B. Number of system impact studies completed by the Responsible Party during the reporting quarter more than 60 days after the Responsible Party received an executed system impact study agreement,

C. For all system impact studies completed more than 60 days after receipt of an executed system impact study agreement, average number of days study was delayed due to transmission customer's actions (e.g., delays in providing needed data),

D. Mean time (in days), for all system impact studies completed by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the executed system impact study agreement to the date when the Responsible Party provided the system impact study to the entity who executed the system impact study agreement, and

E. Mean cost of system impact studies completed by the Responsible Party during the reporting quarter.

iii. Transmission service requests withdrawn from the system impact study queue.

A. Number of transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter,

B. Number of transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter more than 60 days after the Responsible Party received the executed system impact study agreement, and

C. Mean time (in days), for all transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter, from the date the Responsible Party received the executed system impact study agreement to date when request was withdrawn from the Responsible Party's system impact study queue.

iv. Process time from completed system impact study to offer of facilities study.

A. Number of new facilities study agreements delivered during the reporting quarter to entities that request transmission service,

B. Number of new facilities study agreements delivered during the reporting quarter to entities that request transmission service more than thirty (30) days after the Responsible Party completed the system impact study,

C. Mean time (in days), for all facilities study agreements delivered by the Responsible Party during the reporting quarter, from the date when the Responsible Party completed the system impact study to the date when the Responsible Party delivered a facilities study agreement, and

D. Number of new facilities study agreements executed during the reporting quarter.

v. Facilities study processing time.

A. Number of facilities studies completed by the Responsible Party during the reporting quarter,

B. Number of facilities studies completed by the Responsible Party during the reporting quarter more than 60 days after the Responsible Party received an executed facilities study agreement,

C. For all facilities studies completed more than 60 days after receipt of an executed facilities study agreement, average number of days study was delayed due to transmission customer's actions (e.g., delays in providing needed data),

D. Mean time (in days), for all facilities studies completed by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the executed facilities study agreement to the date when the Responsible Party provided the facilities study to the entity who executed the facilities study agreement,

E. Mean cost of facilities studies completed by the Responsible Party during the reporting quarter, and

F. Mean cost of upgrades recommended in facilities studies completed during the reporting quarter.

vi. Service requests withdrawn from facilities study queue.

A. Number of transmission service requests withdrawn from the Responsible Party's facilities study queue during the reporting quarter,

B. Number of transmission service requests withdrawn from the Responsible Party's facilities study queue during the reporting quarter more than 60 days after the Responsible Party received the executed facilities study agreement, and

C. Mean time (in days), for all transmission service requests withdrawn from the Responsible Party's facilities study queue during the reporting quarter, from the date the Responsible Party received the executed facilities study agreement to date when request was withdrawn from the Responsible Party's facilities study queue.

2. The Responsible Party is required to post the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section for each calendar quarter within 15 days of the end of the calendar quarter. The Responsible Party will keep the quarterly measures posted on OASIS for three calendar years.

3 The Responsible Party will be required to post on OASIS the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section in the event the Responsible Party, for two consecutive calendar quarters, completes more than twenty (20) percent of the studies associated with requests for transmission service from entities that are not Affiliates of the Responsible Party more than sixty (60) days after the Responsible Party delivers the appropriate study agreement. The Responsible Party will have to post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section until it processes at least ninety (90) percent of all studies within 60 days after it has received the appropriate executed study agreement. For the purposes of calculating the percent of studies completed more than sixty (60) days after the Responsible Party delivers the appropriate study agreement, the Responsible Party should aggregate all system impact studies and facilities studies that it completes during the reporting quarter.

i. Mean, across all system impact studies the Responsible Party completes during the reporting quarter, of the employee hours expended per system impact study the Responsible Party completes during reporting period;

ii. Mean, across all facilities studies the Responsible Party completes during the reporting quarter, of the employee-hours expended per facilities study the Responsible Party completes during reporting period;

iii. The number of employees the Responsible Party has assigned to process system impact studies;

iv. The number of employees the Responsible Party has assigned to process facilities studies.

4. The Responsible Party is required to post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section for each calendar quarter within 15 days of the end of the calendar quarter. The Responsible Party will keep the quarterly measures posted on OASIS for five calendar years.

i. Posting data related to grants and denials of service. The Responsible Party is required to post data each month listing, by path or flowgate, the number of transmission service requests that have been accepted and the number of transmission service requests that have been denied during the prior month. This posting must distinguish between the length of the service request (e.g., short-term or long-term requests) and between the type of service requested (e.g., firm point-to-point, non-firm point-to-point or network service). The posted data must show:

1. The number of non-Affiliate requests for transmission service that have been rejected,

2. The total number of non-Affiliate requests for transmission service that have been made,

3. The number of Affiliate requests for transmission service, including requests by the transmission provider's merchant function to designate a network resource or to procure secondary network service, that have been rejected, and

4. The total number of Affiliate requests for transmission service, including requests by the transmission provider's merchant function to designate, or terminate the designation of a network resource or to procure secondary network service, that have been made.

j. Posting re-dispatch data.

1. The Transmission Provider must allow the posting on OASIS of any third party offer to relieve a specified congested transmission facility.

2. The Transmission Provider must post on OASIS (i) its monthly average cost of planning and reliability re-dispatch, for which it invoices customers, at each internal transmission facility or interface over which it provides re-dispatch service and (ii) a high and low re-dispatch cost for the month for each of these same transmission facilities. The transmission provider must post this data on OASIS as soon as practical after the end of each month, but no later than when it sends invoices to transmission customers for re-dispatch-related services.

k. Posting of historical area control error data. The Transmission Provider must post on OASIS historical one minute and ten-minute area control error data for the most recent calendar year, and update this posting once per year.

1.3 Auditing Transmission Service Information.

a. All OASIS database transactions, except other transmission-related communications provided for under 1.2(g)(2), must be stored, dated, and time stamped.

b. Audit data must remain available for download on the OASIS for 90 days, except ATC/TTC postings that must remain available for download on the OASIS for 20 days. The audit data are to be retained and made available upon request for download for five years from the date when they are first posted in the same electronic form as used when they originally were posted on the OASIS.

1.4 Obligations of OASIS users.

Each OASIS user must notify the Responsible Party one month in advance of initiating a significant amount of automated queries. The OASIS user must also notify the responsible Party one month in advance of expected significant increases in the volume of automated queries.

2. Business Practice Standards and Communication Protocols for Public Utilities

2.1 Incorporation by Reference of North American Energy Standards Board Wholesale Electric Quadrant Standards.

a. The Transmission Provider will comply with the following business practice and electronic communication standards promulgated by the North American Energy Standards Board Wholesale Electric Quadrant, which are incorporated herein by reference:

1. Open Access Same-Time Information Systems (OASIS), Version 1.5 (WEQ-001, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and

September 8, 2009, with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-9.7, 001-14.1.3, and 001-15.1.2);

2. Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.5 (WEQ-002, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

3. Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.5 (WEQ-003, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

4. Coordinate Interchange (WEQ-004, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

5. Transmission Loading Relief—Eastern Interconnection (WEQ-008, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

6. Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

8. Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.5 (WEQ-013, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009); and

9 Business Practices for Measurement and Verification of Wholesale Electricity Demand Response (WEQ-015, 2010 Annual Plan Items 4(a) and 4(b), March 21, 2011).

10. Business Practice Standards for Measurement and Verification of Energy Efficiency Products (WEQ-021, 2010 Annual Plan Item 4(d), May 13, 2011).

2.2 Communication and Information Sharing Among Public Utilities and Pipelines

a. The Transmission Provider may share non-public, operational information with a pipeline operator, or another utility for the purpose of promoting reliable service or operational planning.

b. Except as permitted in paragraph (a) of this section, MECL, as defined in this section, and its employees, contractors, consultants, and agents are prohibited from disclosing, or using anyone as a conduit for the disclosure of, non-public, operational information received from a pipeline pursuant to a third party or to its marketing function employees as that term is defined in its standards of conduct.

3.0 Exceptions

The terms and conditions documented in Attachment P Sections 1 and 2 are adopted from American regulations 18 C.F.R. §37 and 18 C.F.R. §38. The Transmission Provider adopts the following exceptions to those terms and conditions.

3.1 Exceptions to Attachment P Section 1 Open-Access Same-Time Information Systems

a. With respect to Section 1.2 (b)(3), FIRM/NON-FIRM ATC, TTC, CBM and TRM can be queried by hour, day, week, month or year for a span not exceeding 10 years.

b. For clarity, with respect to Section 1.2(f) IRAC may incur internal costs for equipment and services to access the OASIS such as a computer, digital certificates, and internet service.

c. For greater clarity, the posting of information to a Transmission Provider public website dedicated to transmission system operations subjects shall be considered as meeting the requirements of posting to OASIS.

d. For greater clarity, with respect to section 1.2(2)(ii), the request must have been received prior to the posting for the specific time limit to apply.

3.2 Exceptions to Attachment P Section 2 Incorporation by Reference of North American Energy Standards Board Wholesale Electric Quadrant Standards

a. The Transmission Provider's implementation of Network Service in OASIS makes use of certain mechanisms that are also required for Point-to-Point Service. This method does not allow for designation of Network Resources on OASIS, so this work is done off-line. Implementation of Network Service in OASIS in accordance with the standards referenced in Section 2.1 will not occur until the anticipated benefits exceed the anticipated costs.

MARITIME ELECTRIC
A FORTIS COMPANY

OATT Standards of Conduct

Table of Contents

1. Requirements

a. As more fully described and implemented in subsequent sections of this part, MECL must treat all transmission customers, affiliated and non-affiliated, on a not unduly discriminatory basis, and must not make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage with respect to any transmission of electric energy.

b. As more fully described and implemented in subsequent sections of this part, MECL's transmission function employees must function independently from marketing function employees, except as permitted in this part or otherwise permitted by IRAC order.

c. As more fully described and implemented in subsequent sections of this part, MECL and its employees, contractors, consultants and agents are prohibited from disclosing, or using a conduit to disclose, non-public transmission function information to marketing function employees.

d. As more fully described and implemented in subsequent sections of this part, MECL must provide equal access to non-public transmission function information disclosed to marketing function employees to all its transmission customers, affiliated and non-affiliated, except as permitted in this part or otherwise permitted by IRAC order.

2. Definitions

a. **Affiliate** of a specified entity means:

1. Another person that controls, is controlled by or is under common control with, the specified entity. An affiliate includes a division of the specified entity that operates as a functional unit.
2. "Control" as used in this definition means the direct or indirect authority, whether acting alone or in conjunction with others, to direct or cause to

direct the management policies of an entity. A voting interest of 10 per cent or more creates a rebuttable presumption of control.

b. **Internet website** refers to the Internet location where MECL posts the information, by electronic means, required under these Standards of Conduct.

c. **IRAC** means the Island Regulatory and Appeals Commission.

d. **Marketing functions** means the sale for resale, or the submission of offers to sell, of electric energy or capacity, demand response, virtual transactions, or financial or physical transmission rights, all as subject to an exclusion for bundled retail sales.

e. **Marketing function employee** means an employee, contractor, consultant or agent of MECL or of an affiliate of MECL who actively and personally engages on a day-to-day basis in marketing functions.

f. **Open Access Same Time Information System** or OASIS refers to the Internet location where MECL posts the information required by Section 4 of its OATT, and where it may also post the information required to be posted on its Internet Web site by these Standards of Conduct.

g. **OATT** means the MECL Open Access Transmission Tariff.

h. **Transmission** means electric transmission, network or point-to-point service, ancillary services or other methods of electric transmission, or the interconnection with other transmission facilities.

i. **Transmission customer** means any eligible customer, shipper or designated agent that can or does execute a transmission service agreement or can or does receive transmission service, including all persons who have pending requests for transmission service or for information regarding transmission.

j. **Transmission functions** means the planning, directing, organizing or carrying out of day-to-day transmission operations, including the granting and denying of transmission service requests.

k. **Transmission function employee** means an employee, contractor, consultant or agent of MECL who actively and personally engages on a day-to-day basis in transmission functions.

l. **Transmission function information** means information relating to transmission functions.

m. **Transmission service** means the provision of any transmission as defined in Section 2(h) of these Standards of Conduct.

n. **Waiver** means the determination by MECL, if authorized by its OATT, to waive any provisions of its OATT for a given entity.

3. Non-discrimination Requirements

a. MECL must strictly enforce all OATT provisions relating to the sale or purchase of open access transmission service, if the OATT provisions do not permit the use of discretion.

b. MECL must apply all OATT provisions relating to the sale or purchase of open access transmission service in a fair and impartial manner that treats all transmission customers in not an unduly discriminatory manner, if the OATT provisions permit the use of discretion.

c. MECL may not, through its OATTs or otherwise, give undue preference to any person in matters relating to the sale or purchase of transmission service (including, but not limited to, issues of price, curtailments, scheduling, priority, ancillary services, or balancing).

d. MECL must process all similar requests for transmission in the same manner and within the same period of time in comparable circumstances.

4. Independent Functioning Rule

a. **General rule**. Except as permitted in this part or otherwise permitted by IRAC order, MECL's transmission function employees must function independently of marketing function employees.

b. **Separation of functions**

1. MECL is prohibited from permitting marketing function employees to:

i. Conduct transmission functions; or

ii. Have access to the system control centre or similar facilities used for transmission operations that differs in any way from the access available to other transmission customers.

2. MECL is prohibited from permitting its transmission function employees to conduct marketing functions.

5. No-Conduit Rule

a. MECL is prohibited from using anyone as a conduit for the disclosure of non-public transmission function information to MECL marketing function employees or marketing function employees of third parties.

b. An employee, contractor, consultant or agent of MECL, and an employee, contractor, consultant or agent of an affiliate of MECL that is engaged in marketing functions, is prohibited from disclosing non-public transmission function information to any marketing function employees.

6. Transparency Rule

a. **Contemporaneous disclosure**

1. If MECL discloses non-public transmission function information, other than information identified in paragraph (a)(2) of this section, in a manner contrary to the requirements of Section 5, MECL must immediately post the information that was disclosed on its Internet website.

2. If MECL discloses, in a manner contrary to the requirements of Section 5, non-public transmission customer information, or any other information that IRAC has determined is to be subject to limited dissemination, MECL must immediately post notice on its website that the information was disclosed.

b. **Exclusion for specific transaction information**

MECL's transmission function employee may discuss with marketing function employees a specific request for transmission service submitted by the marketing function employee. MECL is not required to contemporaneously disclose information otherwise covered by Section 5 if the information relates solely to a marketing function employee's specific request for transmission service.

c. **Voluntary consent provision**

A transmission customer may voluntarily consent, in writing, to allow MECL to disclose the transmission customer's non-public information to marketing function employees. If the transmission customer authorizes MECL to disclose information to marketing function employees, MECL must post notice on its Internet website of that consent along with a statement that it did not provide any preferences, either operational or rate-related, in exchange for that voluntary consent.

d. **Posting implementation procedures on the Internet website**

MECL must post on its Internet website current procedures for implementing the Standards of Conduct.

e. **Identification of affiliate information on the Internet website**

1. MECL must post on its Internet website the names and addresses of all its affiliates that employ or retain marketing function employees.
2. MECL must post on its Internet website a complete list of the employee staffed facilities shared by any of MECL's transmission function employees and marketing function employees. The list must include the types of facilities shared and the addresses of the facilities.
3. MECL must post information concerning potential merger partners as affiliates that may employ or retain marketing function employees, within seven days after the potential merger is announced.

f. **Identification of employee information on the Internet website**

1. MECL must post on its Internet website the job titles and job descriptions of its transmission function employees.

2. MECL must post a notice on its Internet website of any transfer of a transmission function employee to a position as a marketing function employee, or any transfer of a marketing function employee to a position as a transmission function employee. The information posted under this section must remain on its Internet website for 90 days. No such job transfer may be used as a means to circumvent any provision of this part. The information to be posted must include:
   i. The name of the transferring employee,
   ii. The respective titles held while performing each function (i.e., as a transmission function employee and as a marketing function employee), and
   iii. The effective date of the transfer.

g. **Timing and general requirements of postings on the Internet website**

1. MECL must update on its Internet website the information required by the Standards of Conduct within seven business days of any change, and post the date on which the information was updated. MECL may also post the information required to be posted under these Standards of Conduct on its OASIS, but is not required to do so.
2. In the event an emergency, such as an earthquake, flood, fire or hurricane, severely disrupts MECL's normal business operations, the posting requirements in this part may be suspended by MECL. If the disruption lasts longer than one month, MECL must so notify IRAC and may seek a further exemption from the posting requirements.
3. All Internet website postings required by this part must be sufficiently prominent as to be readily accessible.

h. **Exclusion for and recordation of certain information exchanges**

1. Notwithstanding the requirements of Sections 4(a) and 5, MECL's transmission function employees and marketing function employees may exchange certain non-public transmission function information, as delineated in Section 6(h)(2), in which case MECL must make and retain a

contemporaneous record of all such exchanges except in emergency circumstances, in which case a record must be made of the exchange as soon as practicable after the fact. MECL shall make the record available to IRAC upon request. The record may consist of hand-written or typed notes, electronic records such as e-mails and text messages, recorded telephone exchanges, and the like, and must be retained for a period of five years.

2. The non-public information subject to the exclusion in Section 6(h)(1) is as follows:

    i. Information pertaining to compliance with Reliability Standards, and

    ii. Information necessary to maintain or restore operation of the transmission system or generating units, or that may affect the dispatch of generating units.

i. **Posting of waivers**

MECL must post on its Internet website notice of each waiver of an OATT provision that it grants in favour of an affiliate, unless such waiver has been approved by IRAC. The posting must be made within one business day of the act of a waiver. MECL must also maintain a log of the acts of waiver, and must make it available to IRAC upon request. The records must be kept for a period of five years from the date of each act of waiver.

7. Implementation Requirements

a. **Effective date**

MECL must be in full compliance with the standards of conduct on the date it commences transmission transactions with an affiliate that engages in marketing functions.

b. **Compliance measures and implementation procedures**

1. MECL must implement measures to ensure that the requirements of Sections 4 and 5 are observed by its employees and by the employees of its affiliates.
2. MECL must distribute the implementation procedures referred to in Section 6 (d) to all its transmission function employees, marketing function employees, officers, directors, supervisory employees, and any other employees likely to become privy to transmission function information.

c. **Training and compliance personnel**

1. MECL must provide annual training on the Standards of Conduct to all the employees listed in paragraph (b)(2) of this section. MECL must provide training on the Standards of Conduct to new employees in the categories listed in paragraph (b)(2) of this Section, within the first 30 days of their employment. MECL must require each employee who has taken the training to certify electronically or in writing that he or she has completed the training.
2. MECL must designate a chief compliance officer who will be responsible for standards of conduct compliance. MECL must post the name of the chief compliance officer and provide his or her contact information on its Internet Web site.

d. **Books and records**

MECL must maintain books of account and records related to compliance to the Standards of Conduct separately from those of its affiliates that employ or retain marketing function employees and these must be available to IRAC upon request.

8. Waiver from Standards of Conduct Requirement

MECL may file a request to IRAC for a waiver from some of the requirements of this Standards of Conduct.

Appendix SOC-1

Standards of Conduct Implementation Procedures

1. Introduction

The intent of MECL is to implement Standards of Conduct ("SOC") governing itself and affiliates which substantially conform to those required by the U.S. Federal Energy Regulatory Commission ("FERC") as set out in Order 717. These procedures implement the SOC and apply to interactions and communications between transmission function employees, marketing function employees, officers, directors, supervisory employees, and any other employees likely to become privy to transmission function information in performing their roles and responsibilities. Accordingly, this document will be distributed to these employees and any new employees that fall within these categories and posted on the Internet website. This SOC refocuses the rules on the areas in which there is the greatest potential for abuse and eliminate barriers to the free flow of information that does not have material potential for abuse.

2. Rules

In the context of the basic principle that transmission providers must provide open, non-discriminatory and comparable transmission service to all transmission customers, the SOC are designed to promote the following rules:

a. **Independent Functioning:** MECL's transmission function employees (TFEs) must function independently from MECL's marketing function employees (MFEs) or the MFEs of its affiliate, Energy Marketing, except in emergency circumstances.

b. **No Conduit Rule:** MECL's employees, contractors, consultants and agents may not disclose, or use a conduit to disclose, non-public transmission function information (TFI) to MECL's MFEs or the MFEs of its affiliate, Energy Marketing, unless limited exceptions apply.

c. **Transparency Rule:** MECL shall comply with the SOC in a transparent manner through compliance with various posting requirements, and will provide equal access to non-public TFI to all of its affiliated and non-affiliated transmission customers in accordance with the SOC.

3. Key Definitions

a. **Employee** means any employee, contractor, consultant or agent. All MECL employees are required to comply with the SOC.

b. **Chief Compliance Officer (CCO)** means the person MECL has designated to be responsible for SOC compliance.

c. **No Conduit Rule** means MECL employees (as defined above) are prohibited from serving as, or using anyone else as, a conduit for the disclosure of non-public TFI to its marketing function employees or marketing function employees of its affiliate, NBEM unless limited exceptions apply.

d. **Non-public** means not posted on MECL's external website or an Open Access Same-Time Information System (OASIS) or not otherwise simultaneously available to all transmission customers and potential transmission customers.

e. **Transmission Provider** means MECL.

f. **Open Access Same-Time Information System (OASIS):** The real-time information sharing system used to communicate with customers, provide transmission system information, process requests for transmission service and post certain SOC requirements.

g. **Marketing Function** involves the sale for resale, or the submission of offers to sell, of electric energy or capacity, demand response, virtual transactions, or financial or physical transmission rights, all as subject to an exclusion for bundled retail sales.

h. **Marketing Function Employee (MFE)** means an employee of MECL or of an affiliate of MECL who actively and personally engages on a day-to-day basis in marketing functions.

i. **Transmission Function** involves the planning, directing, organizing or carrying out of day-to-day transmission operations, including the granting and denying of transmission service requests. The transmission function includes activities focused on short-term real time operations, including those decisions made in advance of real time but directed at real time operations, and activities that support the granting or denying of requests for transmission service including interconnection service.

j. **Transmission Function Employee (TFE)** means an employee of MECL who actively and personally engages on a day-to-day basis in transmission functions.

k. **Transmission Function Information (TFI)** means information related to day-to-day transmission operations and includes but not limited to: Available Transmission Capacity (ATC), outages, price of transmission, curtailments, and balancing, and also includes transmission customer information.

l. **Undesignated Employee (UE)** means an employee of MECL or an affiliate of MECL that is not designated as a transmission function employee or as a marketing function employee.

m. **Energy Control Centre** means the operations centre for the transmission system, where operators control, monitor, and operate MECL's transmission system.

n. **Internet website** refers to the Internet location where MECL posts the information, by electronic means, required under these Standards of Conduct.

4. Independent Functioning of TFEs and MFEs

MECL's TFEs function separately and independently from MECL's MFEs or MFEs of MECL's affiliate, Energy Marketing, except in emergency circumstances.

a. Physical Separation and Access Restrictions

MECL's TFEs are primarily located at the Energy Control Centre ("ECC") located on Cumberland Street in Charlottetown, PEI, approximately one kilometer from MECL's head office at 180 Kent Street, Charlottetown, PEI. MECL maintains strict procedures and physical access restrictions to regulate access to the ECC, all of which are approved by the Director of Compliance.

MECL does not currently conduct day-to-day marketing functions. If it does in the future the MFEs will be located at MECL's head office in an area physically separated from other work areas in the building. They will have electronic card access to their own work area, which will not be accessible to any other MECL employees.

MECL's transmission engineering and planning department are both located at MECL's head office. As a result, system impact studies to support Transmission Service Requests are also carried out at MECL's Head Office, and the employees who perform those functions are designated as TFEs.

The ECC back up Control Centre is located at #3 Fourth Street in West Royalty at MECL's West Royalty Service Centre. The backup control centre is tested periodically by TFEs who typically perform the majority of their work at the ECC. For this reason, both of these work areas are physically separated from other work areas, and card access to both areas is restricted, such that both areas are inaccessible to MFEs.

Despite these measures, MECL has deemed its head office a shared facility.

b. Interactions and Meetings

Interactions and meetings between TFEs and MFEs are restricted under the SOC. Interactions between MECL employees that include both MFEs and TFEs generally should be limited to social activities or to necessary discussions about:

i. an MFE's own request for transmission service,
ii. the design and development of, and compliance with, Reliability Standards,
iii. investigation and remediation of potential violations of such standards, and
iv. information necessary to maintain or restore operation of a transmission system generation units, or that may affect the dispatch of generating units.

These interactions in which non-public transmission information may be disclosed can only take place in accordance with Section 6.

Other types of permissible interactions and meetings where no non-public TFI could be discussed includes:

i. discussion of Regional Transmission Organization and Independent System Operator issues,
ii. participation in legal or regulatory proceedings involving the transmission provider,
iii. attending the same industry meetings or events,
iv. joint meetings for disaster/outage preparation training,
v. attending transmission provider-sponsored meetings with customers, and
vi. discussions with the transmission provider's marketing groups (marketing of transmission services, not electricity).

These interactions may also include long-range integrated planning, but only when conducted through the Transmission System Users Group.

Undesignated employees, including undesignated employees that may become privy to transmission function information in the course of performing their work, may interact freely with both MFEs and TFEs, subject always to compliance with the No Conduit Rule.

5. No Conduit Rule and Non Discriminatory Information Access

MECL's No Conduit Rule prohibits the disclosure of non-public TFI to MFEs of MECL and its affiliates, except as permitted under section 6 of these procedures. In addition, the OATT sets out the terms and conditions by which MECL conducts business with transmission customers and potential transmission customers, whether affiliated or not, to provide equal access to non-public transmission function information.

Transmission information is considered "public" and <u>not restricted</u> under the SOC if the information is posted on MECL's Internet website, posted on MECL's OASIS (either the secure portion or the publicly accessible portion) or otherwise simultaneously available to all other MECL transmission customers or potential transmission customers.

If non-public TFI is disclosed to MFEs of MECL or its affiliates in contravention of this rule, then an immediate posting must be made of the information disclosed, unless the information is customer information, in which case an immediate posting of the fact of the improper disclosure must be made.

6. Permitted Disclosure of Non-Public Transmission Function Information to MFEs

The SOC permit limited interaction and meetings involving only TFEs and MFEs of MECL or its affiliates, and the disclosure of non-public transmission function information to the MFEs, in the following circumstances:

a. **MFE's Own Request for Transmission Service:** TFEs or undesignated employees may discuss with an MFE of MECL or an affiliate a specific request for transmission service submitted by the MFE. The discussion may include non-public transmission function information pertaining solely to the specific request for transmission service submitted by the MFE. A contemporaneous record must be made of any information exchanged under this exception, however, MECL is not required to contemporaneously disclose or post such information if it relates solely to the MFE's specific request for transmission service.

b. **Transmission Customer's Voluntary Consent:** Transmission customers may voluntarily consent, in writing, to allow MECL to disclose the customer's non-public information to MFEs of MECL or an affiliate. MECL must post notice of the consent on its website prior to any disclosure, along with a statement that it did not provide any operational or rate-related preferences in exchange for the voluntary consent. Voluntary consents are to be posted on the Internet website or the publicly accessible portion of OASIS. No other contemporaneous disclosure or posting is required.

c. **Information Pertaining to Compliance with Reliability Standards:** TFEs or undesignated employees may disclose to MFEs of MECL or an affiliate non-public TFI pertaining to compliance with reliability standards adopted by MECL. A contemporaneous record must be made of any information exchanged under this exception. In emergency circumstances, a record of the exchange may be made as soon as practical.

d. **Information Necessary to Restore or Maintain System Operation:** TFEs or undesignated employees may disclose to MFEs of MECL or an affiliate non-public transmission function information necessary to maintain or restore operation of the transmission system and generating units, or that may affect the dispatch of generating units. A contemporaneous record must be made of any information exchanged under this exception. In emergency circumstances, a record of the exchange may be made as soon as practicable after the fact.

When a contemporaneous record is required, the record may consist of handwritten or typed notes, electronic records such as e-mails and text messages, recorded telephone exchanges, and the like. The record must be retained for five years.

7. Training

All TFEs, MFEs, supervisors, officers, directors, and any other employees likely to become privy to non-public TFI must receive annual SOC training. All new employees in these categories will receive training within 30 days of their hire date. All MECL employees must receive annual SOC training, and in particular on their obligations under the No Conduit Rule. Employees must certify in writing or electronically that they have received the training.

8. Open Access Transmission Tariff and Notices of Waivers

The OATT sets out the price, terms, and conditions by which MECL conducts business with transmission customers and potential transmission customers. The OATT is posted on MECL's public website. MECL is required to post a notice of waiver on its Internet website or the publicly accessible portion of its OASIS whenever it waives any OATT provision in favor of MECL or an affiliate. The posting must be made within one business day of the act of the waiver. MECL must also maintain a log of the acts of waiver, and must make it available to the IRAC upon request. The records must be kept for a period of five years from the date of each act of waiver.

9. Standards of Conduct Posting Requirements

The SOC requires MECL to maintain specific information on the Internet website or the publicly accessible portion of OASIS. All information must be updated within seven business days of any change and must include the date on which the information was updated. MECL will post the following information:

a. **Chief Compliance Officer:** MECL has designated its Internal Auditor as its Chief Compliance Officer.

b. **Affiliate Information:** MECL currently has no subsidiary marketing affiliates but as a subsidiary corporation of Fortis is affiliated with other Fortis owned utilities located in Belize, Turks and Caicos, United States and Canada. None of these affiliates conduct marketing functions in PEI and none are Transmission Customers of MECL.

c. **Shared Facilities:** MECL's head office at 180 Kent Street is deemed a shared facility.

d. **Transmission Function Employees:** MECL will post the job titles and job descriptions of all MECL TFEs.

e. **Transfers:** MECL posts any transfer of an employee or an employee of an affiliate from a transmission function to a marketing function or from a marketing function to a transmission function. Postings include name of employee, job titles of both the vacated position and the new position, and the effective date. The information must be posted under this section for 90 days.

f. **Implementation Procedures**: MECL posts these procedures for implementing the SOC.

g. **Voluntary Consents:** MECL posts notice of any voluntary consent provided by customers to authorize MECL to disclose non-public customer information to MFEs of MECL or an affiliate. MECL posts notice of the consent along with a statement that it did not provide any preferences, either operational or rate-related, to obtain the consent.

h. **Information Disclosures:** MECL must immediately post any disclosures of non-public transmission function information to a MFE of MECL or an affiliate, unless one of the exceptions discussed in Section 6 applies. Disclosures should be reported immediately by calling the SOC Emergency Contact.

i. **Potential Mergers:** MECL must post information concerning potential merger partners as affiliates that may employ or retain MFE within seven days after the potential merger is announced.

10. Chief Compliance Officer

MECL's Chief Compliance Officer is the Company's Internal Auditor who may be reached at 180 Kent Street, Charlottetown, PE, C1A7N2.

11. Questions and Inquiries

Email: SOC-Compliance@maritimeelectric.com

Phone: 902 629-3655

MARITIME ELECTRIC
A FORTIS COMPANY

August 9, 2016

hand

RECEIVED
9:45 AM
AUG 09 2016
The Island Regulatory and Appeals Commission

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

Dear Commissioners:

Further to the Company's filing of an Open Access Transmission Tariff Application ("the Application") on July 8, 2016 please find enclosed 10 copies of the 2014 Cost Allocation Study ("the Study") undertaken by Chymko Consulting Ltd. on behalf of the Company. This Study should be considered supplementary evidence to the Application and included as Appendix M to the Application.

If you require further information, please do not hesitate to contact me at (902) 629-3667.

Yours truly,

MARITIME ELECTRIC

S. D. Loggie
Vice President, Finance
and Chief Financial Officer

SDL41
Encl. as noted

cc: R. O. Younker
J. Cunniffe
A. S. Orford
J. D. Gaudet
J. Roberts

APPENDICES

CHYMKO

CHYMKO CONSULTING LTD.
535, 1015 – 4th Street SW
Calgary, Alberta T2R 1J4

403.781.7691
www.chymko.com

September 2, 2015

Jason Roberts
Maritime Electric Company, Ltd.
180 Kent Street
Charlottetown, PE C1A 7N2

Dear Mr. Roberts

SUBJECT: 2014 Cost Allocation Study

Please find attached the findings of Chymko Consulting's Electric Utility cost allocation study to assist Maritime Electric with a its upcoming rate proposal to the Island Regulatory and Appeals Commission.

We appreciate the time and effort of Maritime Electric staff to provide us with the necessary data and information to conduct this study. Should you have any questions or comments on this report, please contact me at (403) 781-7691.

Yours truly,

M Turner

Michael Turner
President

cc: Gloria Crockett

Attachment

CHYMKO

2014 Cost Allocation Study

Maritime Electric

September 2, 2015

www.chymko.com

EXECUTIVE SUMMARY

1. Maritime Electric Company Ltd. (MECL) retained Chymko Consulting Ltd. to perform a comprehensive cost allocation study to support a future rate proposal to the Island Regulatory and Appeals Commission (IRAC). The following report provides the results of this study, which is based on MECL's Statement of Earnings for twelve months ending on December 31, 2014.

2. A cost allocation study first functionalizes revenue requirement (in this case, the Statement of Earnings), essentially seeking to attribute the full cost of service to a specific purpose, such as power supply, transmission, distribution network, services and metering, customer care, and lighting. Next, the cost allocation study classifies each function as demand, energy, or site related depending upon how the cost of that function might vary with how end-use customers use the system. Finally, the cost allocation study will allocate the functionalized and classified expenses to rate classes.

3. Table A below summarizes MECL's allocated revenue requirement.

Table A
Allocated 2014 Net Revenue Requirement from Rates ($,000)

	Revenue Collected	Allocated Cost	Revenue to Cost Ratio	2008 Study
Residential	45.0 %	48.9 %	92 %	91 %
Residential (S)	2.2 %	2.3 %	97 %	122 %
Farm	3.3 %	4.0 %	81 %	N/A
General Service 1	32.3 %	27.5 %	117 %	114 %
General Service 1 (S)	0.9 %	0.7 %	115 %	132 %
General Service 2	0.8 %	0.7 %	120 %	122 %
Small Industrial	6.6 %	6.8 %	96 %	109 %
Large Industrial	7.5 %	7.5 %	100 %	86 %
Lights	1.3 %	1.3 %	103 %	119 %
Unmetered	0.2 %	0.2 %	103 %	98 %
Total	100.0 %	100.0 %	100 %	100 %

4. Allocated cost is one bookend for a 2016 rate proposal, representing the cost to provide electric utility service for each rate class. If cost causation were the only consideration, for instance, Table A indicates that 2016 rates should seek to recover 48.9 percent of 2016 revenue requirement from the Residential rate class, 2.3 percent from the Seasonal Residential rate class, and so on.

5. Another consideration is how much the rate for each class of customer would have to change to recover allocated cost. By the current revenue to cost ratios shown in Table A above, some rates would need to change significantly. Subject to full consideration of all rate design principles and further analysis of any such change, it may well be that rate rebalancing would need to be implemented gradually over the course of multiple years.

TABLE OF CONTENTS

1 INTRODUCTION

6. Maritime Electric Company Ltd. (MECL) retained Chymko Consulting Ltd. to perform a comprehensive cost allocation study to support a future rate proposal to the Island Regulatory and Appeals Commission (IRAC). Based on the assumptions discussed in this report, Chymko Consulting's cost allocation study takes as a starting point MECL's Statement of Earnings for twelve months ending on December 31, 2014. Contained in MECL's December 2014 monthly financial report submitted to IRAC, the Statement of Earnings represents the total cost of providing electric utility service at a rate of return determined by the 2012 PEI Energy Accord.

7. A cost allocation study will typically begin with "revenue requirement," which represents the forecast cost of providing electric utility service based on a regulator-approved rate of return. MECL's 2014 Statement of Earnings is similarly based on a rate of return deemed to be in the public interest insofar as it is compliant with the 2012 PEI Energy Accord. Therefore, the principle difference between the Statement of Earnings and revenue requirement is that the Statement of Earnings is calculated after-the-fact and revenue requirement is typically forward-looking. MECL has traditionally filed cost allocation studies based on actual expenses from the previous calendar year, and in using the 2014 Statement of Earnings this study is no different.

8. This study examines the detailed expenses underlying the Statement of Earnings and assigns, attributes, or allocates expenses to each of MECL's rate classes. The fully-allocated 2014 Statement of Earnings by rate class then becomes an important benchmark to inform MECL's anticipated 2016 rate proposal. If the residential rate class is attributed fifty percent of 2014 expenses, for instance, then this information can serve as a target or objective for designing 2016 residential rates.

9. The first step of a cost allocation model is to group similar types of expenses that make up revenue requirement into elements of service, or functions. For each function, the user of the cost allocation model must consider:

- Is the function incurred for the purpose of servicing all rate classes, a sub-set of rate classes, or a single rate class?

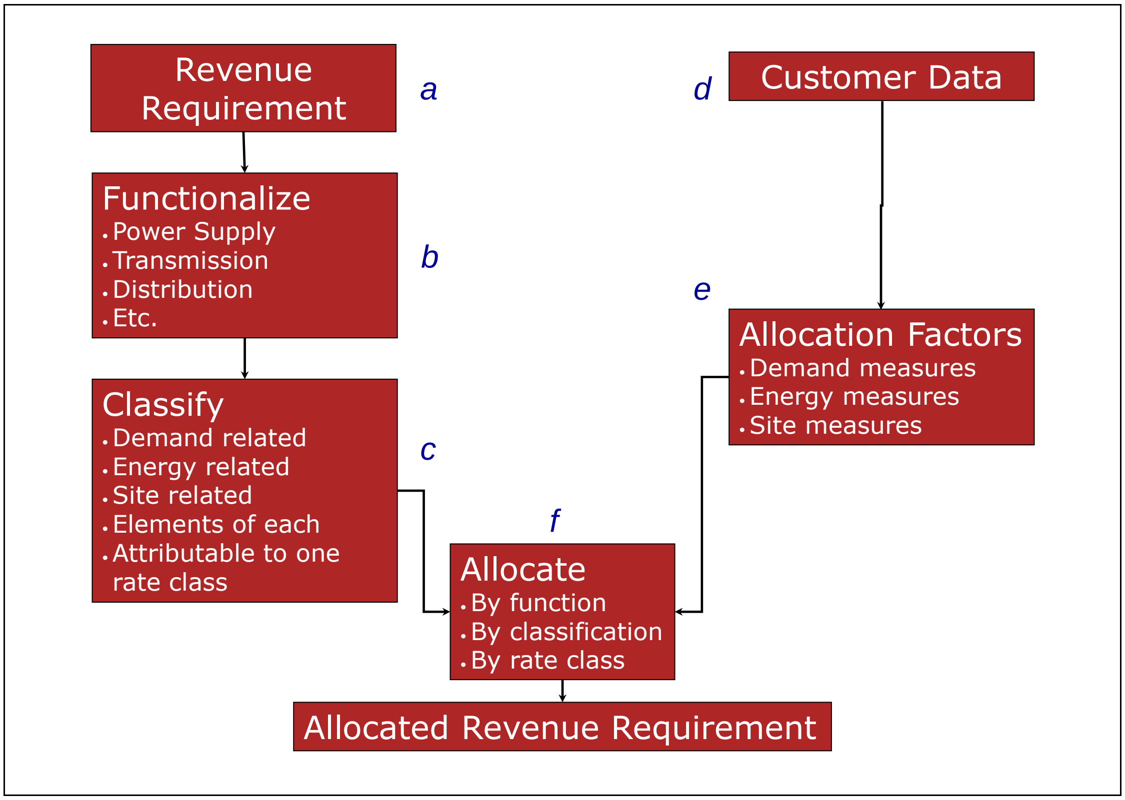
- If the function is attributable to more than one rate class, how might the cost of that function vary depending upon how end-use customers use the distribution system? For example, does the cost vary with peak daily demand changes? Does it vary with the total amount of energy delivered? Does it vary with the number of distribution sites served?

- How does each rate class contribute to the use of distribution infrastructure? For example, how does each rate class contribute to total peak demand and total energy delivered? How many sites are served in each rate class?

10. In order to answer the above questions, cost allocation studies follow a structured process, which can be explained with the aid of Figure 1 below. Taking revenue requirement (labelled

as a) as a given, the first step is known as functionalization (labelled as b), which begins with attributing each line item in the study by its purpose or function.

Figure 1: Process of a cost allocation study



11. The next step in a cost allocation study is called classification (c). The purpose of classification is to determine how each function might vary based on how end-use customers use the system. Sometimes, a function exists solely for the purpose of serving a subset of rate classes, perhaps only a single rate class. However, as long as the function is attributable to more than one rate class, it is necessary to explore further as to whether the expense will vary with peak demand on the system, the amount of energy consumed, or the number of sites served by the system. Thus, each function is classified as demand-related, energy-related, site-related, or a combination of the three.

12. The final step of a cost allocation study is to allocate the functionalized and classified revenue requirement to rate classes. The choice of allocation factor is to a large degree influenced by the classification of each functionalized detail of revenue requirement. For example, demand related costs are generally allocated by the same proportions as the peak demand of each rate class. Similarly, energy related costs are allocated by the same proportions as energy sales and site related costs are allocated by the relative size of each rate class.

13. The development of allocation factors starts with the collection of MECL's system load data and billing statistics (d). From this foundation along with any associated load research data, it is possible to calculate allocation factors based on each rate classes' peak demand, energy consumption, and the number of sites per rate class.

14. As suggested by the overview above, the process of a cost allocation study is relatively uncomplicated given there is agreement upon how a cost is to be functionalized, classified, and allocated. Thus, generally accepted principles and methods have evolved out of a number of years of regulatory experience. Regulated distribution utilities must file cost allocation studies to demonstrate that its tariffs are just and reasonable. Generally accepted methods typically evolve out of the regulatory process, but even these continue to evolve with industry changes and provincial government policy. Furthermore, every utility is different and every utility service area has its own unique characteristics and issues that may justify a different method. Therefore, it is important to justify the rationale for every cost functionalization, classification, and allocation decision, regardless of whether it is a commonly accepted standard or not.

2 FUNCTIONALIZATION

15. The starting point for cost allocation is the 2014 MECL Statement of Earnings. This is summarized in Table 1 below.

Table 1[1]
MECL 2014 Statement of Earnings (Revenue Requirement)
$,000

	Twelve Months ending December 31, 2014
Operating Expenses	
Energy Costs	106,818
ECAM Adjustment	12,358
Net Energy Costs	119,176
Distribution	3,925
Transmission	922
Transmission and Distribution - Other	1,994
Transmission - OATT	172
General	11,025
Total Operating Expenses	137,214
Amortization	
Amortization Other	688
Amortization Plant And Equipment	14,761
Total Amortization	15,450
Total Operating Income	159,130
Financing Expenses	
Long-Term Debt	11,983
Short-Term Debt	500
Interest Charged To Construction	(368)
Amortization of Financing Costs	5
Total Financing Expenses	12,119
Earnings before Income Taxes	164,782
Income Taxes	5,658
Net Earnings	12,246
Gross Revenue Requirement	182,686
OATT Revenue	(1,830)
Other Revenue[2]	(1,852)
Net Revenue Requirement	179,004

16. Net earnings identified is equivalent to the allowed return on equity for a prospective revenue requirement. This is because MECL has already adjusted 2014 net earnings to account for customer refunds associated with ECAM 2003 and the maximum rate of return allowed by the 2012 PEI Energy Accord.

17. Note that the Statement of Earnings in Table 1, subject to two exceptions, is the same format as previous IRAC filings. Both Open Access Transmission Tariff (OATT) Revenue and Other Revenue are explicitly identified in Table 1. If not for these sources of revenue, end-user

[1] Table totals in this report may not reconcile due to rounding.
[2] Inclusive of pole rental revenue.

rates would need to recover $182.7 Million, which is labelled as Gross Revenue Requirement. Net of these revenue sources, the Net Revenue Requirement is $179.0 Million. Subject to ECAM and rate of return adjustments noted above (see paragraph 16), $179.0 Million was recovered from end-user rates in 2014.

2.1 METHOD

18. Chymko Consulting's cost allocation study fully attributes revenue requirement in Table 1 to one of sixteen functions discussed below. For purposes of summary, the sixteen functions are also discussed under six general categories: power supply, transmission, distribution network, services and metering, customer care, and lighting.

Power Supply

- Generation: MECL's Borden and Charlottetown generating facilities, which are typically dispatched for peak demand and backup purposes.
- Purchased Power: Energy supply purchases from NB Power, which are typically dispatched for base load and ancillary service requirements.

Transmission

- High-voltage transmission facilities operating at a voltage of 69 kV or greater.

Distribution Network

- Substations: Facilities used to regulate and step-down voltages from transmission facilities to distribution lines.
- Primary Lines: Bulk distribution lines used to deliver energy from substations to localized distribution transformers.
- Transformers: Facilities used to regulate and step-down voltages from primary distribution lines to a voltage more suitable for the end-use consumer.
- Secondary Lines: Local distribution lines operating at a consumer-level voltage that service multiple end-use customers.

Services and Metering

- Service Lines: Local distribution lines operating at a consumer-level voltage that connect the distribution network to the meter of a single, end-use customer.
- Meter Assets: Metering infrastructure used to measure and record energy consumed by each end-use customer.

- Meter Reading: The process of collecting and processing end-use customer metering data, primarily for the purpose of billing.

Customer Care

- Billing: The process of preparing and delivering invoices to end-use customers for power supply and use of the MECL system.

- Remittance & Collection: The accounts receivable process of collecting and processing end-use customer bill payments.

- Uncollectibles & Damage Claims: Uncollectibles are associated with the cost of outstanding customer invoices (e.g. bad debts), whereas damage claims represent claims against MECL for damage to customers' property.

- Service Connections: Activities related to the connection or re-connection of customers, which may include off-cycle meter reads as well as modifications or additions to secondary lines, service lines, and meters. MECL recovers the cost of these activities under sections O-1 and O-2 of its tariff.

- Late Payments: Penalty revenues associated with consumer accounts in arrears, as recovered under section O-3 of the MECL tariff.

Lighting

- Facilities dedicated to the use of providing electric service to street and area lighting, as defined under sections N-22, N-23, N-25, and N-26 of the MECL tariff.

19. Chymko Consulting functionalizes revenue requirement as per a series of methods and assumptions summarized in Table 2 below. Overall, this table demonstrates that 66% of revenue requirement is directly assigned to a function. An additional 29% is functionalized according to the same proportions as the underlying facilities and assets, the majority of which are also directly assignable because of detailed asset records. A further 3% is allocated by the same proportions by which labour cost is functionalized, which leaves 2% to be allocated by various methods involving professional judgement.

Table 2 Methods to Functionalize 2014 MECL Revenue Requirement					
	Direct Assign	Assets & Facilities	Labour	Profes-sional Judgment	Total
Operating Expenses					
Energy Costs	99 %	1 %	0 %	1 %	100 %
ECAM Adjustment	100 %	0 %	0 %	0 %	100 %
Net Energy Costs	99 %	1 %	0 %	1 %	100 %
Distribution	17 %	77 %	0 %	7 %	100 %
Transmission	100 %	0 %	0 %	0 %	100 %
Transmission and Distribution - Other	5 %	95 %	0 %	0 %	100 %
Transmission - OATT	100 %	0 %	0 %	0 %	100 %
General	6 %	15 %	52 %	26 %	100 %
Total Operating Expenses	88 %	5 %	4 %	3 %	100 %
Amortization					
Amortization Other	48 %	16 %	36 %	0 %	100 %
Amortization Plant And Equipment	0 %	100 %	0 %	0 %	100 %
Total Amortization	2 %	96 %	2 %	0 %	100 %
Total Operating Income	79 %	15 %	4 %	3 %	100 %
Financing Expenses					
Long-Term Debt	0 %	100 %	0 %	0 %	100 %
Short-Term Debt	0 %	100 %	0 %	0 %	100 %
Interest Charged To Construction	0 %	100 %	0 %	0 %	100 %
Amortization of Financing Costs	0 %	100 %	0 %	0 %	100 %
Total Financing Expenses	0 %	100 %	0 %	0 %	100 %
Earnings before Income Taxes	73 %	21 %	4 %	2 %	100 %
Income Taxes	0 %	100 %	0 %	0 %	100 %
Net Earnings	0 %	100 %	0 %	0 %	100 %
Gross Revenue Requirement	66 %	29 %	3 %	2 %	100 %
OATT Revenue	100 %	0 %	0 %	0 %	100 %
Other Revenue	60 %	39 %	0 %	0 %	100 %
Net Revenue Requirement	66 %	29 %	3 %	2 %	100 %

20. To the extent that the information exists and it is practical to do so, the first priority in functionalization is to directly attribute as much as possible to a given function without the need to allocate. Indeed, MECL provided Chymko Consulting with detailed financial accounting records that allowed it to directly assign two thirds of revenue requirement to one of the sixteen functions.

21. That which cannot be directly assigned is allocated. Amortization, debt financing, return, and income tax are the most important examples of a functional allocation. These expenses comprise more than one fifth of the MECL revenue requirement and only indirectly are they associated with the sixteen functions. Amortization, debt financing, and return are all calculated based on MECL's infrastructure investment and therefore the underlying infrastructure becomes a determining factor as to how these expenses should be functionalized. Moreover, MECL pays income tax only if it earns a positive return and therefore, tax is also indirectly associated with utility infrastructure.

22. Chymko Consulting allocates these expenses by the same proportions as the underlying capital infrastructure, which means that gross plant and depreciation must also be fully attributed to each of the sixteen functions. MECL's detailed plant records facilitate a relatively straightforward functionalization process: two-thirds of gross plant in service is directly attributable to a single function and an additional thirty percent is attributable to a narrow subset of the sixteen functions.

23. The next-most important functionalization method as it affects total revenue requirement is general operating expenses that are non-specific to any particular utility function. For instance, over two-thirds of general operating costs are mostly related to corporate supervisory salaries and employment benefits. Because these corporate overheads exist for the purpose of all other personnel, Chymko Consulting allocated such expenses by the same proportions as all other labour expenses already attributed to the sixteen functions.

24. The final category of functionalization method used is broadly described as professional judgement in Table 2. This actually describes seven different methods that are applied on a case-by-case basis depending upon the nature of the expense. The two most important methods, as measured by total expense allocated, are used for the allocation of energy control centre expenses and the allocation of finance administration costs. In the case of the former, this and previous studies rely on the professional judgement of MECL staff to functionalize energy control centre: one-quarter to power supply, one-quarter to transmission, and the remaining amount to the distribution network. In the case of financial administration, approximately half of the annual expense is postage and stationary associated with billing and the other half is labour cost. For the half that is labour, expenses are functionalized according to the work responsibilities of the seven personnel in that department.

2.2 RESULT

25. The outcome of the functionalization process is summarized in Table 3 below.

Table 3 Functionalized MECL Revenue Requirement ($,000)							
	Power Supply	Trans'n	Distrib'n Network	Services and Metering	Customer Care	Lighting	Total
Operating Expenses							
Energy Costs	105,188	1,209	419	2	0	0	106,818
ECAM Adjustment	12,358	0	0	0	0	0	12,358
Net Energy Costs	117,545	1,209	419	2	0	0	119,176
Distribution	65	65	3,257	512	0	26	3,925
Transmission	0	922	0	0	0	0	922
T&D - Other	0	0	1,994	0	0	0	1,994
Transmission - OATT	0	172	0	0	0	0	172
General	2,701	1,324	3,597	1,063	2,320	20	11,025
Total Operating Expenses	120,312	3,693	9,266	1,577	2,320	46	137,214
Amortization							
Other	429	145	109	6	0	0	688
Plant And Equipment	3,241	1,777	7,225	2,319	61	138	14,761
Total Amortization	3,670	1,922	7,334	2,324	61	138	15,450
Total Operating Income	123,981	5,615	16,601	3,902	2,381	184	152,663
Financing Expenses							
Long-Term Debt	2,630	1,429	5,910	1,881	49	84	11,983
Short-Term Debt	110	60	246	78	2	4	500
Charged To Construction	(81)	(44)	(182)	(58)	(2)	(3)	(368)
Amortization of Financing	1	1	2	1	0	0	5
Total Financing Expenses	2,660	1,445	5,977	1,902	50	85	12,119
Earnings before Tax	126,641	7,060	22,578	5,804	2,431	269	164,782
Income Taxes	1,242	675	2,790	888	23	40	5,658
Net Earnings	2,688	1,460	6,040	1,922	51	86	12,246
Gross Revenue Requirement	130,570	9,194	31,409	8,614	2,505	394	182,686
OATT Revenue	0	(1,830)	0	0	0	0	(1,830)
Other Revenue	(35)	(19)	(652)	(25)	(1,120)	(1)	(1,852)
Net Revenue Requirement	130,535	7,345	30,757	8,589	1,385	393	179,004

26. The results in Table 3 are consistent with previous studies to the extent that Chymko Consulting has as much generally followed the same methods of previous studies.[3] Compared to Chymko Consulting's 2008 cost allocation study for MECL, the largest shift in functionalized expense is related to power supply, which has dropped from eighty one percent to seventy three percent of the total functionalized cost (see Table 4 below). Chymko Consulting attributes this result to reduced power import costs compared to 2008 as the result of a five-year Power Purchase Agreement effective March 1, 2011.

27. Excluding power supply from the analysis, Table 4 also demonstrates that there is a shift in functionalized expenses from service lines and meters toward transmission and distribution networks. Chymko Consulting attributes this outcome to MECL's infrastructure investments since 2008, which ultimately affect how amortization, debt financing, return, and income tax are all functionalized.

[3] Exceptions are minor and are noted in paragraph 28.

Table 4 Functionalized MECL Revenue Requirement ($,000)							
	Power Supply	Trans'n	Distrib'n Network	Services and Metering	Customer Care	Lighting	Total
Percent of total							
2014 Revenue Requirement	73 %	4 %	17 %	5 %	1 %	0 %	100 %
2008 Revenue Requirement	81 %	4 %	10 %	5 %	1 %	0 %	100 %
Excluding Power Supply							
2014 Revenue Requirement	N/A	15 %	63 %	18 %	3 %	1 %	100 %
2008 Revenue Requirement	N/A	19 %	52 %	23 %	5 %	1 %	100 %

28. Also as part of MECL's improved cost reporting processes, the utility is more accurately identifying general operating expenses, administration, and supervision attributable to customer care, thus reducing the dependence on allocations. Chymko Consulting therefore views this internal improvement to have the added benefit of improving the accuracy of the cost allocation study.

3 CLASSIFICATION

29. Functionalized revenue requirement is next classified based on the generally accepted cost drivers that can be measured in terms of how customers use the system. Costs associated with upstream functions are generally accepted to be a function of the peak demand placed on the system and are classified accordingly. At the other extreme, downstream functions, such as services and metering, are generally a function of the number of sites served.[4]

3.1 METHOD

Power Supply

30. In the context of a vertically integrated and regulated electric utility, power supply requirements are generally considered to be a function of both peak demand and total energy consumed. Power supply is a function of total energy consumed because all else equal, a utility with 50,000 GWh of annual sales would incur higher power supply costs than a utility with 1,000 GWh of annual sales. However, even among two utilities with the same annual sales, generation resource planning (and therefore, cost) will differ based on the peak hourly demand. While a consistently flat electrical load may be better served by larger generating facilities suited for full-on production, a variable and peaking load will require a different mix of generating resources. Options for meeting variable peak demand may include smaller scale facilities, technologies that are able to ramp-up production on relatively short notice, or a combination of the two.

31. MECL's objective for this study is to apply methods that are consistent with previous studies. Therefore, this study continues with the same basic principles followed in previous MECL cost allocation studies in which power supply is classified as a combination of demand and energy related.[5] Purchases from NB Power and wind farms are classified as energy related because they are used to supply MECL's base load requirements. However, MECL's fixed annual payments for the capital cost of NB Power's Point Lepreau generating facilities is considered demand related.

32. Capital and operating costs associated with MECL's on-island generation resources are classified as demand related because on-island generation sources are called upon when supply from NB Power is insufficient to meet MECL demand. On the other hand, MECL's Energy Control Centre (ECC) is classified as ninety five percent energy related because the main purpose of the ECC is to manage and coordinate the delivery of energy supply. Because

[4] Note that Chymko Consulting's report often uses the term "sites" as opposed to "customers" in the context of a cost allocation study. The purpose of this terminology is to be clear that a cost allocation study is concerned with attributing revenue requirement to distribution points of delivery or "sites." Some customers may actually be served by multiple sites.

[5] A refinement to this study is to further differentiate demand-related capacity costs required for firm load such that they may be allocated to rate classes based on peak demand of firm load.

at least a portion of ECC activities must ultimately feed into long term resource planning, five percent of the ECC expenses are classified as demand related.[6]

Transmission

33. Transmission lines are part of a bulk delivery system that ultimately services all utility customers, including wholesale customers. Transmission infrastructure is unaffected by the addition of one more customer, unless the addition of that customer is expected to materially affect peak system demand. Chymko Consulting therefore considers transmission lines to be demand related and allocates these functions on the basis of coincident peak demand.[7] Coincident peak demand is appropriate for this allocation because transmission facilities must be capable of providing service during the time of system peak. PEI's demand for electricity is at its highest during the winter, and therefore MECL's backbone delivery system must be designed to accommodate peak demand at this time.

Distribution Network

34. Substations are part of a bulk delivery system that services virtually all of MECL customers. Also similar to transmission infrastructure, substations are generally unaffected by the addition of one more customer, unless the addition of that customer is expected to materially affect peak system demand. Thus, substations are classified as demand related and allocated on the basis of coincident peak demand.[8]

35. Functions such as primary lines, transformers, and secondary lines also form MECL's distribution network. These facilities must also be designed to meet peak demand, but it is also true that the cost of these functions will increase as more customers are added to the system. Expanding the distribution system to service new customers will require MECL to extend distribution lines and install new transformers, and so there will be a base level cost regardless of the capacity that these facilities will be required to carry.

36. This cost allocation study continues with the same basic principles followed in previous MECL cost allocation studies. MECL considers that circumstances have not materially changed and the Company's objective for this study is to apply consistent methods to previous studies and facilitate a more meaningful comparison of results over time. Thus, lines are classified as 50% demand related and 50% site related[9] whereas transformers are classified as 60% demand related and 40% site related.

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[6] Prior to 1994, previous cost studies have also classified fuel and a portion of variable O&M expenditures related to on-island generation as energy related. Chymko Consulting understands that MECL generating resources are used more sparingly in recent years, thus only increasing the likelihood that they will be used for periods of peak demand.

[7] For transmission lines, peak demand is measured at the transmission system level including losses, which as noted earlier are not evenly distributed between rate classes.

[8] The allocator for substations is also adjusted to recognize that some large industrial customers are serviced at a transmission voltage and do not use substation facilities.

[9] For the allocation of distribution network functions, allocators are adjusted to recognize that some distribution customers are serviced at a primary voltage and do not use a MECL transformer or secondary line.

Services, Metering, and Customer Care

37. Functions such as service lines, metering, meter reading, billing, remittance & collection, and uncollectibles & damage claims are all classified as site related. It is generally recognized that the cost of these functions will primarily vary with the number of customers served. Factors other than demand, energy or sites also play a role in cost causation, but these adjustments are made by the choice of allocation and are discussed further in Section 4.

38. Finally, functions associated with service connections and late payments are also classified as site related. From a cost causation perspective, MECL tracks cost by rate class and so classification of these functions is mainly for presentation purposes. In Section 4, these functions are allocated to rate classes in the exact same proportion as actual revenue.

3.2 RESULT

39. MECL's classified revenue requirement is summarized in Table 5 below.

Table 5 Classified 2014 MECL Revenue Requirement ($,000)				
	Demand	Energy	Site	Total
Operating Expenses				
Energy Costs	28,982	77,734	101	106,818
ECAM Adjustment	2,715	9,643	0	12,358
Net Energy Costs	31,697	87,377	101	119,176
Distribution	1,987	6	1,932	3,925
Transmission	922	0	0	922
T&D - Other	1,163	0	831	1,994
Transmission - OATT	172	0	0	172
General	5,869	337	4,820	11,025
Total Operating Expenses	41,810	87,720	7,684	137,214
Amortization	0	0	0	
Other	370	270	48	688
Plant And Equipment	8,853	304	5,604	14,761
Total Amortization	9,223	575	5,652	15,450
Total Operating Income	51,033	88,294	13,336	152,663
Financing Expenses	0	0	0	
Long-Term Debt	7,247	169	4,567	11,983
Short-Term Debt	302	7	190	500
Charged To Construction	(223)	(5)	(140)	(368)
Amortization of Financing	3	0	2	5
Total Financing Expenses	7,329	171	4,619	12,119
Earnings before Tax	58,362	88,466	17,955	164,782
Income Taxes	3,422	80	2,156	5,658
Net Earnings	7,406	173	4,667	12,246
Gross Revenue Requirement	69,189	88,719	24,778	182,686
OATT Revenue	(1,830)	0	0	(1,830)
Other Revenue	(384)	(2)	(1,467)	(1,852)
Net Revenue Requirement	66,976	88,716	23,311	179,004

40. Chymko Consulting has applied the same methods as previous studies, and to the extent that the results in Table 5 vary from previous studies it is because different parts of revenue requirement will change at varying rates of growth. For instance, expenses related to power supply have dropped materially (see Section 3.2) and because most of power supply is classified as energy related, energy related revenue requirement also decreases. In Table 6 below, energy related revenue requirement decreases from sixty percent in the 2008 study to fifty percent in the current study.

41. Excluding power supply from the analysis, Table 6 also demonstrates the effect of shifts noted in functionalization. As per Section 2.2, the shift in functionalized expenses toward the transmission and distribution networks means that more of revenue requirement is classified as demand related.

Table 6 Classified MECL Revenue Requirement ($,000)				
	Demand	Energy	Site	Total
Percent of total				
2014 Revenue Requirement	37 %	50 %	13 %	100 %
2008 Revenue Requirement	30 %	60 %	10 %	100 %
Excluding Power Supply				
2014 Revenue Requirement	52 %	0 %	48 %	100 %
2008 Revenue Requirement	49 %	0 %	51 %	100 %

4 ALLOCATION

42. Once revenue requirement is classified between demand, energy, and site related, the next step is to allocate revenue requirement to rate classes. This requires some consideration of how customers should be grouped into rate classes for purposes of allocation as well as choosing the appropriate allocator for each expense.

4.1 RATE CLASSES

43. As a general principle, cost recovery and cost causation are the two basic reasons or rationales for grouping distribution sites into rate classes. Cost recovery is a matter of fairness because a significant portion of fixed infrastructure costs are recovered through usage-based rates. Usage and infrastructure cost are positively correlated, but because usage tends to increase at a faster rate than cost, a single rate class would unfairly recover a disproportionate amount of cost from higher-usage customers. In other words, an end-use customer that uses twice the energy does not necessarily cause the utility to incur two times the infrastructure cost. In fact, it is entirely possible that the two customers could require exactly the same infrastructure, but one customer will pay much more because rates are often usage-based. Separating customers into rate classes allows the utility to set different rates for each rate class so as to reduce this disparity.

44. Cost causation is the other reason or rationale for rate classes. Given that the objective of cost allocation is to fairly apportion revenue requirement to end-use distribution customers, then it is necessary to group customers by similar infrastructure cost characteristics. It is important to note that distribution infrastructure characteristics need not be identical within a rate class and infrastructure itself is not necessarily sufficient justification to create a new rate class. In fact, distribution infrastructure characteristics will never be identical within any group of any material size. In addition to being administratively impractical to administer dozens of rate classes, it is not a theoretical imperative for all customers within a rate class to be perfectly homogenous.[10] Nevertheless, creating rate classes of similar cost characteristics allows the utility to allocate or assign cost in a way that acknowledges the infrastructure used by each rate class.

45. MECL rate classes and rate structure is a product of a 1990s regulatory framework that obliged MECL to adopt the same rate schedules as New Brunswick Power. As MECL returns to a more traditional cost-of-service regulatory framework, its long-term intention is to fully rationalize the definition of rate classes and the rate structure within each rate class. This process will be gradual so as to minimize customer impacts.

[10] In practice, there are a number of other factors that will mitigate differences in distribution infrastructure. For instance, the utility's contribution policy helps to levelize construction costs before they are added to rate base. In addition, higher costs not addressed by the contribution policy are often associated with greater usage and higher revenue since a large portion of utility costs is recovered from an energy charge.

46. MECL's immediate and primary concern to be addressed in an upcoming tariff application is the composition of the residential rate class and the declining two-block rate structure.[11] The benefit of a declining block rate structure is the ability to fairly recover fixed cost when there is a wide range of low and high use customers in one rate class. From a purely cost-causation perspective, revenue from high-use customers tends to increase at a faster rate than the cost to serve so a declining per-kWh rate is one method (among several) to address this issue. The downside of a declining blocked rate is that it also communicates to the customer that the *value* of energy is decreasing with every kWh consumed. This is also contrary to the long run view that the utility's cost per-kWh is actually increasing because increased consumption accelerates the need for major infrastructure upgrades.

47. MECL is intending to phase out the residential declining block rate structure, subject to managing the transitional impacts. In this regard, one area of concern for MECL is the fact that the current residential rate class includes farm customers. Specifically, MECL has observed that farms consume twice the energy per customer than the average residential customer. Whereas the second energy block would rarely apply to the average (non-farm) residential customer, approximately fifty percent of the farm customers' energy charges are associated with the second energy block.[12] Thus, eliminating the declining block structure would have a disproportionate impact on farm customers.

48. Eliminating the declining block rate is more easily managed if farm customers are first separated from the residential rate class. Thus, Chymko Consulting modified its cost allocation model to accommodate an additional farm rate class separate from residential. This preparatory work for rate design will allow MECL to calculate two different per-kWh rates for each rate class with due regard for the impact on each group. For this study, Chymko Consulting assumed the same service line cost and pro-rated peak demand (based on energy sales). Although not modelled in this cost allocation study, further analysis might establish differences in the cost of a service line (due to distances involved) and a different peak demand profile. Depending upon the conclusions of that analysis, farm customers might be better justified to be part of a small general service rate class, or left as its own unique rate class.

4.2 ALLOCATORS

49. The final step of the cost allocation study is to allocate the utility's classified revenue requirement to rate classes. The choice of allocation factor is to a large degree influenced by classification. For example, demand related costs are generally allocated by the same proportions as the peak demand of each rate class. Similarly, energy related costs are allocated by the same proportions as energy sales and site related costs are allocated by the

[11] As of March 1, 2014, the residential per-kWh rate was $0.1278 / kWh for the first 2,000 kWh and $0.0985 / kWh thereafter.

[12] The exception to this rule is seasonal farm customers, which are much more similar to equivalent seasonal residential customers. In the conclusions of Section 5, Chymko Consulting recommends that these customers remain in the residential seasonal rate class.

relative number of sites within each rate class. Below are some common measures of customer usage that are often used as the basis for allocation to rate classes.

Coincident Peak Demand (CP)

50. Coincident peak represents each rate class's contribution to the utility's peak demand day. This is typically measured over the period of one year, but other variants include the sum of peak summer and peak winter demands as well as the sum of daily peak demand for twelve consecutive months. This type of allocator is often paired with demand-related costs associated with high-voltage transmission. The MECL system peak occurs during the winter because lighting and heating demand.

51. While the coincident peak demand allocator recognizes customers are collectively peaking, it also recognizes that that individual customers use energy at different times of the day. For example, a transmission line servicing one 1 MW customer is likely to require higher capacity than a line that services one thousand 1 kW customers who collectively add up to 1 MW. Given that individual customers do not necessarily peak at the same time, this diversity can be factored into transmission system design. The calculation of coincident peak demand also reflects this diversity, making it an appropriate allocator for transmission facilities.

Non-Coincident Peak Demand (NCP)

52. Non-coincident peak demand (NCP) represents the peak demand for each rate class without regard for when the peak occurs for other rate classes. Therefore, the sum of all rate class NCPs is by definition equal to or greater than the system peak. This type of allocator is typically paired with demand-related costs associated with more localized distribution facilities. NCP is widely recognized as an appropriate allocator for components of the distribution system that must be designed and built to handle local peak demand situations that do not necessarily correspond to the overall system peak.

53. Distribution network functions classified as demand related are allocated on the basis of non-coincident peak demand. As facilities become more localized, the needs of specific local customers play a more important role in network design. Individual customers served by a distribution feeder are still diverse, but compared to a bulk transmission system that services a greater number and a broader mix of customers, diversity is less of a factor. Thus, local distribution customers are more likely to peak at the same time compared to a random collection of residential, commercial, and industrial customers. Given that local distribution facilities are more likely to serve one particular rate class, an allocation based on non-coincident rate class peak demand is appropriate. The calculation of non-coincident peak demand reflects diversity within a rate class, but not between rate classes.

Energy Use

54. An energy allocator is calculated from rate class kWh sales, grossed-up for losses. This allocator is used for power supply classified as energy related, but is not otherwise used for the other, wires-related functions.

Number of Sites

55. The number of sites within each rate class is used to allocate site-related costs. Depending upon the function to be allocated, a number of adjustments are required. For instance, the allocation of the secondary lines function should exclude distribution sites that are just served at the primary voltage. Another adjustment is necessary for lighting fixtures and other unmetered points of delivery, which are high in number but the addition of one more fixture should not cause distribution cost to increase as much as the addition of one more residential customer, for example.[13]

56. Furthermore, site counts are sometimes weighted if the per-site cost is known to differ between rate classes and neither a demand nor an energy based allocation is a reasonable alternative. This situation often occurs when a number of factors either directly or indirectly affect the per-site cost and the net impact is material. This is a generally accepted cost allocation practice and in its cost allocation model, Chymko Consulting weights the site-based allocations of functions such as service lines, meter assets, meter reading, billing, and remittance & collection.

57. While the functions for service connection and late payment revenue are classified as site related, this is mainly for completeness. This revenue is directly assigned to rate classes according the same proportions as it was collected.

Summary of Allocators

58. Detailed calculations of all allocators appear in Appendix A and a summary is provided below in Table 7.

[13] In this study, Chymko Consulting discounted the number of lighting fixtures and unmetered points of delivery by a factor of 0.40. Chymko Consulting selected 0.40 such that the allocated secondary distribution voltage cost per fixture is approximately one fifth of a residential customer.

Table 7 Summary of 2014 Peak Demand Allocators				
	Coincident Peak[14] (kW)	Non-Coincident Peak[15] (kW)	Energy Including Losses[14] (MWh)	Sites
Residential	119,190	142,428	515,510	55,530
Residential (S)	738	7,449	18,359	7,328
Farm	10,948	13,082	47,351	1,987
General Service 1	62,272	83,244	399,673	7,049
General Service 1 (S)	0	3,958	8,620	1,711
General Service 2	1,319	2,349	10,023	87
Small Industrial	15,778	32,095	96,049	268
Large Industrial	17,241	2,770	147,055	4
Lights	1,579	1,552	6,772	4,447
Unmetered	359	349	2,612	269
Total	229,423	289,275	1,252,023	78,679

4.3 RESULT

59. MECL's allocated revenue requirement is shown in detail in Appendix A while a simplified version is shown in Table 8 below.

Table 8 Allocated 2014 MECL Revenue Requirement ($,000)						
	Operating Expenses	Capital Expenses	Gross Revenue Require-ment	OATT Revenue	Other Revenue	Net Revenue Require-ment
Residential	63,884	26,034	89,918	(951)	(1,354)	87,614
Residential (S)	2,156	1,965	4,121	(6)	(86)	4,028
Farm	5,548	1,738	7,287	(87)	(26)	7,173
General Service 1	40,323	9,698	50,021	(497)	(266)	49,258
General Service 1 (S)	805	556	1,360	(0)	(20)	1,340
General Service 2	968	216	1,183	(11)	(4)	1,168
Small Industrial	9,888	2,549	12,437	(126)	(62)	12,249
Large Industrial	12,279	1,354	13,634	(137)	(7)	13,489
Lights	1,052	1,273	2,325	(13)	(23)	2,289
Unmetered	311	90	401	(3)	(2)	396
Total	137,214	45,472	182,686	(1,830)	(1,852)	179,004

60. Again, results are consistent with prior studies and differences from the 2008 study are largely caused by how MECL's revenue requirement and customer base has evolved since 2008. A comparison appears below in Table 9.

[14] Calculated at input voltage.
[15] Calculated at primary voltage.

Table 9 Allocated MECL Revenue Requirement ($,000)				
	Total Revenue Requirement		Excluding Power Supply	
	2014	2008	2014	2008
Residential[16]	53 %	50 %	63 %	68 %
Residential (S)[16]	2 %	2 %	5 %	3 %
General Service 1	28 %	30 %	19 %	19 %
General Service 1 (S)	1 %	1 %	2 %	1 %
General Service 2	1 %	0 %	0 %	0 %
Small Industrial	7 %	5 %	5 %	3 %
Large Industrial	8 %	11 %	2 %	2 %
Lights	1 %	1 %	3 %	3 %
Unmetered	0 %	0 %	0 %	0 %
Total	100 %	100 %	100 %	100 %

61. Overall, the Residential rate class as well as General Service 2 and Small Industrial are allocated a greater share of total revenue requirement compared to the 2008 study. Although it has decreased in weight since 2008, the power supply function still represents two thirds of revenue requirement and is mostly allocated on the basis of energy. Residential, General Service 2, and Small Industrial kWh sales per customer all increased from 2008 and consequently, these rate classes receive a larger allocation of power supply cost.

62. When the effects of power supply are excluded, expenses allocated to the Residential rate class actually decrease from the previous study. Section 2.2 noted that expenses related to delivery are shifting toward transmission, which is classified as demand related in Section 3.2. General Service and Industrial sites contribute more to peak demand on a per-customer basis and the end result is that these rate classes are allocated a larger share of delivery compared to 2008.

[16] Including farm for purposes of comparison to 2008.

5 CONCLUSIONS

63. Chymko Consulting's cost allocation study is based on MECL's 2014 Statement of Earnings. To use these results as a yardstick for a 2016 rate proposal, it is necessary to express the allocated net revenue requirement as a percentage share. This adjustment is shown in Table 10.

Table 10
Allocated 2014 Net Revenue Requirement from Rates ($,000)

	Net Revenue Requirement	Percent Share
Residential	87,614	48.9 %
Residential (S)[17]	4,028	2.3 %
Farm	7,173	4.0 %
General Service 1	49,258	27.5 %
General Service 1 (S)	1,340	0.7 %
General Service 2	1,168	0.7 %
Small Industrial	12,249	6.8 %
Large Industrial	13,489	7.5 %
Lights	2,289	1.3 %
Unmetered	396	0.2 %
Total	179,004	100.0 %

64. Allocated cost in Table 10 is only one yardstick or guideline for designing 2016 rates. Other rate design considerations are equally important and one such consideration is the current structure and level of rates. If the desired change is too significant and would cause rate shock (i.e. an increase greater than ten percent of the total bill), then it may be necessary to adopt additional strategies to implement change gradually. One such indicator of the possibility of rate shock is the revenue-to-cost ratio. Table 11 below calculates revenue to cost ratios on current rates as well as providing similarly calculated revenue to cost ratios from the 2008 study.

[17] Of note is the very small allocation to farm customers that are currently billed as Seasonal Residential; this is primarily due to the fact that MECL identified only fifteen such sites in its 2014 data. Chymko Consulting considers there to be too few customers and too few sales to create an administratively feasible rate. Not only is this too small of a sample to depend on consistent cost allocation results over time, but 2014 usage appears very similar to Seasonal Residential and the administration of such a rate class is likely to be burdensome. Thus, Chymko Consulting recommends that these two groups remain in the same Seasonal rate class.

Table 11 Allocated 2014 Net Revenue Requirement from Rates ($,000)				
	Revenue Collected	Allocated Cost	Revenue to Cost Ratio	2008 Study
Residential	45.0 %	48.9 %	92 %	91 %
Residential (S)[18]	2.2 %	2.3 %	97 %	122 %
Farm	3.3 %	4.0 %	81 %	N/A
General Service 1	32.3 %	27.5 %	117 %	114 %
General Service 1 (S)[18]	0.9 %	0.7 %	115 %	132 %
General Service 2	0.8 %	0.7 %	120 %	122 %
Small Industrial	6.6 %	6.8 %	96 %	109 %
Large Industrial	7.5 %	7.5 %	100 %	86 %
Lights[19]	1.3 %	1.3 %	103 %	119 %
Unmetered[19]	0.2 %	0.2 %	103 %	98 %
Total	100.0 %	100.0 %	100 %	100 %

65. Given that the objective of a cost allocation study is to fairly allocate revenue requirement to rate classes on a cost causation basis, a ratio below 100% in Table 11 indicate that (all else equal) rate revenues should be raised for that rate class. Similarly, a ratio above 100% indicates that current rate revenues are above cost and should (all else equal) be lowered.

66. What is generally accepted to be a reasonable revenue to cost ratio will vary among Canadian provinces and regulators. For MECL's specific circumstances, Chymko Consulting considers 100% to be a long term objective, but variances in any given year would be expected and reasonable. Actual rate impacts will depend upon MECL's rate design proposal, and MECL's proposal will need to make such other considerations such as rate shock and whether an overall general rate increase is required for 2016. Moreover, one must take into account that rates are set prospectively and that normal forecast variances in cost, load, and revenue will mean that the intended revenue to cost ratio will rarely be achieved. Pending further rate design analysis, it may be necessary to compromise revenue to cost ratio objectives in the short run so as to mitigate rate shock for one or more rate classes or even subsets of customers within rate classes. In this situation, a short to medium term objective of transitioning customer rates toward a revenue to cost ratio between 90% and 110% may be more reasonable.

67. Unit cost is another output from the cost allocation study with potential use for rate design. Unit cost is calculated by dividing billing units into allocated cost for each rate class. In Table 12 below, Chymko Consulting divides billing demand (i.e. peak demand on the customers' bills) into allocated demand-related cost and number of bills into allocated site-related cost.

[18] The 2008 study underestimated the number of seasonal sites reported in MECL's billing system. This had the effect of understating cost allocated to seasonal rate classes, resulting in an overstated revenue to cost ratio.
[19] The 2008 study allocated lighting and unmetered cost based on number of customer accounts, rather than points of distribution delivery (see paragraph 55).

Table 12 Unit Cost Results for Consideration in Rate Design		
	Demand Related ($/kW/Mo Billing Demand)	Site Related ($/Bill/Mo)
Residential	N/A	24.16
Residential (S)	N/A	44.14
Farm	N/A	25.34
General Service 1	20.21	26.94
General Service 1 (S)	18.26	50.79
General Service 2	19.73	29.87
Small Industrial	17.98	38.40
Large Industrial	12.14	151.77
Lights	N/A	444.72
Unmetered	73.35	62.57
Total	0.00	898.70

68. Site related unit cost gives some indication for an appropriate monthly service charge. Given that the service line, meter, and billing costs are all considered site related, a monthly service charge equal to unit cost would at least ensure the utility is recovering the localized fixed costs from every customer regardless of their consumption. One such application is the seasonal rate, which requires just as much local distribution infrastructure to serve but is billed for only half the year. From a cost-causation perspective, it would be fair for the seasonal rate class to have a higher monthly service charge to ensure these local infrastructure costs are recovered from each site.[20]

69. Similar to the site related unit cost, the demand related unit cost in Table 12 is calculated as the demand related cost divided by the kilowatts billed to customers in that rate class. This only applies to rate classes that are metered and billed for peak demand and unit cost also provides useful information for a potential demand charge. Demand related costs are predominantly related to reserve power supply, transmission, and primary voltage distribution and flowing through the demand related unit cost in the monthly demand charge helps communicate to these customers the value of reducing peak demand.

Final Remarks

70. The overall purpose of a cost allocation study is to develop a benchmark to guide rate design. Rates that reflect the full cost of electric utility service are generally accepted as a worthwhile objective, subject to a number of other considerations that must be taken into account. MECL's existing rate structure presents a number of challenges simply because the basic form and structure has not changed for approximately twenty years. Customer acceptance is an important consideration in rate design and the longevity of the existing structure may make some changes, regardless of their merit, more difficult to accept. It is for this reason that cost allocation results alone should not be the determining factor for rates. The revenue to cost ratios in Table 11 indicates that some rates might need to change significantly. Pending

[20] Note that there is an offsetting effect in which seasonal rate classes are allocated fewer demand related costs because they contribute little to system peak by virtue of being less active in the winter.

further analysis of any such change, it may well be that rate rebalancing would need to be implemented gradually over the course of multiple years.

APPENDIX A: DETAILED SCHEDULES

Schedule Index
Prepared by Chymko Consulting
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SPLIT RESIDENTIAL RATE CLASS

Schedule 1.0											
Summary of Cost Allocation Results											
Revenue Requirement ($,000)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Revenue Collected	83,555	4,090	6,052	59,134	1,598	1,433	12,097	13,813	2,470	419	184,662
less Rate of Return Adjustment	(2,110)	(160)	(140)	(782)	(45)	(17)	(205)	(106)	(101)	(7)	(3,675)
less ECAM 2003 Recovery	(872)	(24)	(80)	(616)	(11)	(15)	(150)	(200)	(11)	(4)	(1,984)
Base Revenue, Comparable for 20:	80,573	3,905	5,832	57,737	1,542	1,400	11,741	13,506	2,358	408	179,004
Revenue Share	45 %	2 %	3 %	32 %	1 %	1 %	7 %	8 %	1 %	0 %	100 %
Allocated Cost (net of Other Reven	87,614	4,028	7,173	49,258	1,340	1,168	12,249	13,489	2,289	396	179,004
Allocated Share	49 %	2 %	4 %	28 %	1 %	1 %	7 %	8 %	1 %	0 %	100 %
Revenue to Cost Ratio	92 %	97 %	81 %	117 %	115 %	120 %	96 %	100 %	103 %	103 %	100 %
Revenue to Cost Ratio (2008 Study	91 %	122 %	N/A	114 %	132 %	122 %	109 %	86 %	119 %	98 %	100 %
Unit Cost											
Demand Related ($/kW/Mo Billing	N/A	N/A	N/A	20.21	18.26	19.73	17.98	12.14	N/A	73.35	0.00
Site Related ($/Bill/Mo)	24.16	44.14	25.34	26.94	50.79	29.87	38.40	151.77	444.72	62.57	898.70

Schedule 1.1											
Unit Cost Summary											
Full Revenue Requirement (¢/kWh Sales)											
	Residenti al	Residenti al (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmeter ed	Total
Operating Expenses											
Energy Costs	9.91	7.25	9.90	8.90	6.77	8.43	9.02	7.44	10.12	8.70	9.15
ECAM Adjustment	1.13	0.87	1.13	1.04	0.83	0.99	1.05	0.88	1.15	1.02	1.06
Net Energy Costs	11.04	8.12	11.03	9.94	7.60	9.42	10.07	8.31	11.27	9.72	10.21
Distribution	0.49	1.28	0.32	0.20	0.80	0.19	0.24	0.02	2.08	0.34	0.34
Transmission	0.10	0.02	0.10	0.07	0.00	0.06	0.07	0.05	0.10	0.06	0.08
Transmission and Distribution -	0.24	0.60	0.17	0.11	0.39	0.11	0.14	0.01	0.86	0.18	0.17
Transmission - OATT	0.02	0.00	0.02	0.01	0.00	0.01	0.01	0.01	0.02	0.01	0.01
General	1.41	2.50	0.94	0.59	1.31	0.49	0.59	0.24	2.53	2.63	0.94
Total Operating Expenses	13.31	12.53	12.58	10.92	10.10	10.27	11.12	8.64	16.87	12.94	11.75
Amortization											
Amortization Other	0.07	0.06	0.07	0.05	0.04	0.05	0.05	0.04	0.11	0.05	0.06
Amortization Plant And Equipm	1.76	3.74	1.28	0.84	2.28	0.74	0.92	0.30	7.12	1.22	1.26
Total Amortization	1.83	3.80	1.34	0.90	2.32	0.78	0.98	0.34	7.23	1.27	1.32
Total Operating Income	15.14	16.33	13.93	11.82	12.43	11.06	12.10	8.98	24.09	14.22	13.07
Financing Expenses											
Long-Term Debt	1.43	3.04	1.04	0.69	1.86	0.60	0.75	0.24	5.26	0.98	1.03
Short-Term Debt	0.06	0.13	0.04	0.03	0.08	0.03	0.03	0.01	0.22	0.04	0.04
Interest Charged To Constructi	(0.04)	(0.09)	(0.03)	(0.02)	(0.06)	(0.02)	(0.02)	(0.01)	(0.16)	(0.03)	(0.03)
Amortization of Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Financing Expenses	1.45	3.07	1.05	0.70	1.88	0.61	0.76	0.25	5.32	0.99	1.04
Earnings before Income Taxes	16.59	19.40	14.98	12.52	14.31	11.66	12.86	9.23	29.41	15.21	14.11
Income Taxes	0.68	1.44	0.49	0.33	0.88	0.28	0.36	0.12	2.48	0.46	0.48
Net Earnings	1.46	3.11	1.06	0.71	1.90	0.61	0.77	0.25	5.38	1.00	1.05
Gross Revenue Requirement	18.73	23.94	16.53	13.55	17.08	12.56	13.99	9.59	37.28	16.66	15.65
OATT Revenue	(0.20)	(0.03)	(0.20)	(0.13)	(0.00)	(0.11)	(0.14)	(0.10)	(0.20)	(0.12)	(0.16)
Other Revenue	(0.28)	(0.50)	(0.06)	(0.07)	(0.25)	(0.05)	(0.07)	(0.01)	(0.38)	(0.09)	(0.16)
Net Revenue Requirement	18.25	23.41	16.27	13.34	16.83	12.40	13.77	9.49	36.70	16.45	15.33

Schedule 1.1											
Unit Cost Summary											
Demand Related Revenue Requirement ($/kW/Mo Billing Demand)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	
Operating Expenses											
Energy Costs	N/A	N/A	N/A	8.72	0.14	7.93	6.95	5.71	N/A	33.80	
ECAM Adjustment	N/A	N/A	N/A	0.82	0.00	0.75	0.66	0.45	N/A	3.20	
Net Energy Costs	0.00	0.00	0.00	9.54	0.14	8.68	7.61	6.16	0.00	37.00	
Distribution	N/A	N/A	N/A	0.62	1.95	0.71	0.70	0.11	N/A	1.86	
Transmission	N/A	N/A	N/A	0.27	0.00	0.24	0.21	0.27	N/A	1.05	
Transmission and Distribution -	N/A	N/A	N/A	0.36	1.15	0.42	0.41	0.05	N/A	1.09	
Transmission - OATT	N/A	N/A	N/A	0.05	0.00	0.05	0.04	0.05	N/A	0.20	
General	N/A	N/A	N/A	1.76	2.03	1.75	1.61	1.18	N/A	6.27	
Total Operating Expenses	N/A	N/A	N/A	12.60	5.27	11.84	10.58	7.83	N/A	47.45	
Amortization											
Amortization Other	N/A	N/A	N/A	0.11	0.06	0.10	0.09	0.08	N/A	0.41	
Amortization Plant And Equipme	N/A	N/A	N/A	2.67	4.31	2.75	2.57	1.57	N/A	9.17	
Total Amortization	N/A	N/A	N/A	2.78	4.37	2.86	2.67	1.65	N/A	9.58	
Total Operating Income	N/A	N/A	N/A	15.39	9.64	14.70	13.25	9.48	N/A	57.03	
Financing Expenses											
Long-Term Debt	N/A	N/A	N/A	2.19	3.60	2.26	2.11	1.29	N/A	7.48	
Short-Term Debt	N/A	N/A	N/A	0.09	0.15	0.09	0.09	0.05	N/A	0.31	
Interest Charged To Constructio	N/A	N/A	N/A	(0.07)	(0.11)	(0.07)	(0.07)	(0.04)	N/A	(0.23)	
Amortization of Financing Costs	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	N/A	0.00	
Total Financing Expenses	N/A	N/A	N/A	2.21	3.64	2.28	2.14	1.31	N/A	7.57	
Earnings before Income Taxes	N/A	N/A	N/A	17.60	13.28	16.98	15.38	10.78	N/A	64.60	
Income Taxes	N/A	N/A	N/A	1.03	1.70	1.07	1.00	0.61	N/A	3.53	
Net Earnings	N/A	N/A	N/A	2.24	3.68	2.31	2.16	1.32	N/A	7.64	
Gross Revenue Requirement	N/A	N/A	N/A	20.87	18.65	20.35	18.54	12.71	N/A	75.77	
OATT Revenue	N/A	N/A	N/A	(0.54)	(0.00)	(0.49)	(0.43)	(0.55)	N/A	(2.08)	
Other Revenue	N/A	N/A	N/A	(0.12)	(0.40)	(0.14)	(0.14)	(0.03)	N/A	(0.35)	
Net Revenue Requirement	N/A	N/A	N/A	20.21	18.26	19.73	17.98	12.14	N/A	73.35	

Schedule 1.1											
Unit Cost Summary											
Energy Related Revenue Requirement (¢/kWh)											
	Residenti al	Residenti al (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmeter ed	Total
Operating Expenses											
Energy Costs	6.67	6.62	6.67	6.72	6.72	6.61	6.71	6.42	6.74	6.74	6.66
ECAM Adjustment	0.83	0.82	0.83	0.83	0.83	0.82	0.83	0.80	0.84	0.84	0.83
Net Energy Costs	7.49	7.45	7.49	7.55	7.56	7.42	7.54	7.22	7.58	7.58	7.48
Distribution	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission and Distribution -	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission - OATT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
General	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total Operating Expenses	7.52	7.47	7.52	7.58	7.59	7.45	7.57	7.25	7.61	7.61	7.51
Amortization											
Amortization Other	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Amortization Plant And Equipm	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total Amortization	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Total Operating Income	7.57	7.52	7.57	7.63	7.63	7.50	7.62	7.30	7.66	7.66	7.56
Financing Expenses											
Long-Term Debt	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Short-Term Debt	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Interest Charged To Constructi	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Amortization of Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Financing Expenses	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Earnings before Income Taxes	7.59	7.54	7.59	7.65	7.65	7.52	7.63	7.31	7.67	7.67	7.58
Income Taxes	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Net Earnings	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.01
Gross Revenue Requirement	15.20	15.10	15.20	15.32	15.32	15.06	15.28	14.64	15.37	15.37	15.17
OATT Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Revenue	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Net Revenue Requirement	15.20	15.10	15.20	15.32	15.32	15.06	15.28	14.64	15.37	15.37	15.17

Schedule 1.1											
Unit Cost Summary											
Site Related Revenue Requirement ($/Bill)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	0.11	0.19	0.11	0.11	0.21	0.11	0.11	0.05	1.89	0.20	3.08
ECAM Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Energy Costs	0.11	0.19	0.11	0.11	0.21	0.11	0.11	0.05	1.89	0.20	3.08
Distribution	2.04	3.62	2.04	2.00	4.04	2.16	2.72	5.13	38.61	3.20	65.56
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission and Distribution -	0.88	1.57	0.88	0.88	1.75	0.88	0.88	0.23	15.33	1.62	24.92
Transmission - OATT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
General	5.42	7.51	5.25	5.14	7.70	5.50	5.61	37.03	38.52	30.89	148.57
Total Operating Expenses	8.45	12.90	8.28	8.13	13.70	8.65	9.32	42.44	94.34	35.92	242.13
Amortization											
Amortization Other	0.05	0.09	0.05	0.05	0.10	0.05	0.06	0.05	0.84	0.09	1.43
Amortization Plant And Equipme	5.71	10.79	5.71	6.52	12.67	7.11	11.26	33.11	126.16	9.20	228.24
Total Amortization	5.77	10.88	5.76	6.57	12.77	7.17	11.31	33.16	127.00	9.28	229.67
Total Operating Income	14.22	23.77	14.04	14.70	26.47	15.82	20.63	75.61	221.35	45.20	471.80
Financing Expenses											
Long-Term Debt	4.67	8.76	4.66	5.62	10.32	6.13	9.79	30.61	91.93	7.33	179.81
Short-Term Debt	0.19	0.37	0.19	0.23	0.43	0.26	0.41	1.28	3.83	0.31	7.50
Interest Charged To Constructi	(0.14)	(0.27)	(0.14)	(0.17)	(0.32)	(0.19)	(0.30)	(0.94)	(2.83)	(0.23)	(5.53)
Amortization of Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.00	0.08
Total Financing Expenses	4.72	8.86	4.71	5.69	10.43	6.20	9.90	30.96	92.97	7.41	181.85
Earnings before Income Taxes	18.94	32.63	18.75	20.39	36.90	22.02	30.53	106.57	314.32	52.61	653.65
Income Taxes	2.20	4.14	2.20	2.65	4.87	2.89	4.62	14.45	43.40	3.46	84.90
Net Earnings	4.77	8.95	4.76	5.74	10.54	6.26	10.00	31.29	93.95	7.49	183.76
Gross Revenue Requirement	25.91	45.72	25.71	28.78	52.31	31.17	45.15	152.31	451.67	63.56	922.31
OATT Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Revenue	(1.74)	(1.58)	(0.37)	(1.84)	(1.53)	(1.30)	(6.76)	(0.54)	(6.96)	(0.99)	(23.61)
Net Revenue Requirement	24.16	44.14	25.34	26.94	50.79	29.87	38.40	151.77	444.72	62.57	898.70

Schedule 1.2											
Unit Cost by Function											
Full Revenue Requirement (¢/kWh Sales)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	2.02	0.47	2.02	1.42	0.14	1.20	1.48	1.05	2.05	1.27	1.62
Purchased Power	10.22	7.89	10.22	9.38	7.53	8.95	9.48	7.92	10.36	9.21	9.55
Transmission	0.79	0.14	0.79	0.54	0.00	0.45	0.57	0.39	0.81	0.48	0.63
Substations	0.32	0.06	0.32	0.21	0.00	0.18	0.23	0.02	0.33	0.19	0.24
Primary Lines	1.61	4.47	1.03	0.66	2.88	0.63	0.83	0.04	6.42	1.24	1.11
Transformers	1.26	3.21	0.89	0.59	2.23	0.59	0.80	0.04	4.34	0.91	0.90
Secondary Lines	0.57	1.58	0.36	0.23	1.01	0.22	0.29	0.02	2.26	0.44	0.39
Service Lines	0.86	3.77	0.34	0.16	2.13	0.09	0.06	0.00	3.72	0.58	0.52
Meter Assets	0.21	0.79	0.08	0.10	0.48	0.05	0.04	0.00	0.00	0.00	0.14
Meter Reading	0.16	0.33	0.06	0.02	0.09	0.01	0.00	0.00	0.00	0.00	0.08
Billing	0.15	0.32	0.06	0.03	0.14	0.01	0.00	0.00	0.05	2.02	0.08
Remittance & Collection	0.13	0.27	0.05	0.02	0.12	0.01	0.00	0.00	0.07	0.12	0.07
Uncollectibles & Damage Claims	0.09	0.34	0.04	0.02	0.17	0.01	0.00	0.00	0.00	0.00	0.05
Service Connections	(0.06)	(0.13)	0.00	(0.00)	(0.02)	0.00	(0.00)	0.00	(0.00)	0.00	(0.03)
Late Payments	(0.10)	(0.07)	0.00	(0.03)	(0.07)	(0.01)	(0.02)	0.00	(0.02)	(0.02)	(0.05)
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.30	0.00	0.03
Total	18.25	23.41	16.27	13.34	16.83	12.40	13.77	9.49	36.70	16.45	15.33
Demand Related Revenue Requirement ($/kW/Mo Billing Demand)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.00	0.00	0.00	5.09	0.00	4.59	4.02	5.16	0.00	19.64	11.50
Purchased Power	0.00	0.00	0.00	7.42	0.00	6.75	5.91	4.09	0.00	28.86	16.28
Transmission	0.00	0.00	0.00	2.16	0.00	1.95	1.71	2.19	0.00	8.33	4.88
Substations	0.00	0.00	0.00	0.85	0.00	0.79	0.70	0.13	0.00	3.39	1.84
Primary Lines	0.00	0.00	0.00	2.02	7.85	2.43	2.43	0.25	0.00	5.65	4.30
Transformers	0.00	0.00	0.00	1.96	7.64	2.36	2.36	0.24	0.00	5.49	4.18
Secondary Lines	0.00	0.00	0.00	0.71	2.77	0.85	0.86	0.09	0.00	1.99	1.51
Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Reading	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Billing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remittance & Collection	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Uncollectibles & Damage Claims	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Connections	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Late Payments	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.00	0.00	0.00	20.21	18.26	19.73	17.98	12.14	0.00	73.35	44.49

Schedule 1.2
Unit Cost by Function

Energy Related Revenue Requirement (¢/kWh)

	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Purchased Power	7.47	7.42	7.47	7.53	7.53	7.40	7.51	7.19	7.55	7.55	7.46
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Substations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transformers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Secondary Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Reading	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Billing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remittance & Collection	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Uncollectibles & Damage Claims	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Connections	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Late Payments	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	7.61	7.56	7.61	7.67	7.67	7.54	7.65	7.33	7.69	7.69	7.60

Site Related Revenue Requirement ($/Bill)

	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Substations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary Lines	6.85	12.26	6.85	6.85	13.65	6.85	6.85	3.43	119.33	12.65	195.57
Transformers	4.44	7.95	4.44	4.44	8.85	4.44	4.44	0.00	77.36	8.20	124.57
Secondary Lines	2.42	4.32	2.42	2.42	4.81	2.42	2.42	0.00	42.06	4.46	67.73
Service Lines	6.23	13.19	6.23	6.88	16.44	8.25	17.72	63.60	75.65	8.02	222.21
Meter Assets	1.54	2.76	1.54	4.33	3.69	4.96	10.02	50.17	0.00	0.00	79.02
Meter Reading	1.16	1.16	1.16	0.71	0.71	1.16	1.16	5.80	0.00	0.00	13.02
Billing	1.11	1.11	1.11	1.11	1.11	1.11	1.11	27.84	1.11	27.84	64.58
Remittance & Collection	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	1.35	1.72	10.51
Uncollectibles & Damage Claims	0.66	1.18	0.66	0.66	1.31	0.66	0.00	0.00	0.00	0.00	5.11
Service Connections	(0.45)	(0.46)	0.00	(0.18)	(0.18)	0.00	(0.14)	0.00	(0.01)	0.00	(1.42)
Late Payments	(0.73)	(0.26)	0.00	(1.20)	(0.53)	(0.91)	(6.13)	0.00	(0.43)	(0.31)	(10.50)
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	128.29	0.00	128.29
Total	24.16	44.14	25.34	26.94	50.79	29.87	38.40	151.77	444.72	62.57	898.70

Schedule 1.3											
Allocated Revenue Requirement ($,000)											
Full Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	47,570	1,248	4,365	32,871	539	794	8,020	10,570	631	209	106,818
ECAM Adjustment	5,434	150	499	3,837	66	93	934	1,247	72	25	12,358
Net Energy Costs	53,004	1,398	4,865	36,708	605	887	8,953	11,817	703	234	119,176
Distribution	2,361	221	141	740	64	18	215	29	130	8	3,925
Transmission	479	3	44	250	0	5	63	69	6	1	922
Transmission and Distribution -	1,174	103	75	408	31	10	124	12	54	4	1,994
Transmission - OATT	89	1	8	47	0	1	12	13	1	0	172
General	6,777	431	416	2,169	105	46	521	339	158	63	11,025
Total Operating Expenses	63,884	2,156	5,548	40,323	805	968	9,888	12,279	1,052	311	137,214
Amortization											
Amortization Other	339	11	29	193	4	4	49	53	7	1	688
Amortization Plant And Equipme	8,460	643	563	3,117	181	69	821	432	444	29	14,761
Total Amortization	8,799	654	593	3,310	185	74	870	485	451	31	15,450
Total Operating Income	72,683	2,810	6,141	43,632	989	1,042	10,759	12,764	1,502	342	152,663
Financing Expenses											
Long-Term Debt	6,879	523	457	2,550	148	57	670	347	328	23	11,983
Short-Term Debt	287	22	19	106	6	2	28	14	14	1	500
Interest Charged To Constructi	(212)	(16)	(14)	(78)	(5)	(2)	(21)	(11)	(10)	(1)	(368)
Amortization of Financing Costs	3	0	0	1	0	0	0	0	0	0	5
Total Financing Expenses	6,957	529	463	2,579	150	57	678	351	332	24	12,119
Earnings before Income Taxes	79,640	3,339	6,603	46,211	1,139	1,099	11,436	13,115	1,834	366	164,782
Income Taxes	3,248	247	216	1,204	70	27	316	164	155	11	5,658
Net Earnings	7,030	535	467	2,606	151	58	685	355	335	24	12,246
Gross Revenue Requirement	89,918	4,121	7,287	50,021	1,360	1,183	12,437	13,634	2,325	401	182,686
OATT Revenue	(951)	(6)	(87)	(497)	(0)	(11)	(126)	(137)	(13)	(3)	(1,830)
Other Revenue	(1,354)	(86)	(26)	(266)	(20)	(4)	(62)	(7)	(23)	(2)	(1,852)
Net Revenue Requirement	87,614	4,028	7,173	49,258	1,340	1,168	12,249	13,489	2,289	396	179,004

Schedule 1.3											
Allocated Revenue Requirement ($,000)											
Demand Related Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	15,492	98	1,423	8,048	2	172	2,056	1,440	205	47	28,982
ECAM Adjustment	1,464	9	134	759	0	16	194	114	19	4	2,715
Net Energy Costs	16,956	107	1,557	8,807	2	188	2,250	1,555	224	51	31,697
Distribution	999	43	92	569	22	15	206	28	11	3	1,987
Transmission	479	3	44	250	0	5	63	69	6	1	922
Transmission and Distribution -	587	25	54	334	13	9	121	12	7	2	1,163
Transmission - OATT	89	1	8	47	0	1	12	13	1	0	172
General	3,025	57	278	1,627	23	38	477	298	38	9	5,869
Total Operating Expenses	22,135	236	2,033	11,633	59	256	3,129	1,974	288	66	41,810
Amortization											
Amortization Other	193	2	18	102	1	2	28	21	2	1	370
Amortization Plant And Equipme	4,527	109	416	2,468	49	60	762	395	56	13	8,853
Total Amortization	4,720	111	434	2,570	49	62	790	416	58	13	9,223
Total Operating Income	26,856	347	2,467	14,204	109	318	3,919	2,390	347	79	51,033
Financing Expenses											
Long-Term Debt	3,700	90	340	2,020	41	49	625	326	46	10	7,247
Short-Term Debt	154	4	14	84	2	2	26	14	2	0	302
Interest Charged To Constructi	(114)	(3)	(10)	(62)	(1)	(2)	(19)	(10)	(1)	(0)	(223)
Amortization of Financing Costs	2	0	0	1	0	0	0	0	0	0	3
Total Financing Expenses	3,742	91	344	2,043	41	49	633	329	46	10	7,329
Earnings before Income Taxes	30,598	438	2,810	16,247	150	368	4,551	2,719	393	89	58,362
Income Taxes	1,747	43	160	954	19	23	295	154	22	5	3,422
Net Earnings	3,781	92	347	2,065	41	50	639	333	47	11	7,406
Gross Revenue Requirement	36,126	572	3,318	19,265	210	441	5,486	3,206	461	105	69,189
OATT Revenue	(951)	(6)	(87)	(497)	(0)	(11)	(126)	(137)	(13)	(3)	(1,830)
Other Revenue	(191)	(9)	(18)	(109)	(4)	(3)	(40)	(7)	(2)	(0)	(384)
Net Revenue Requirement	34,985	558	3,213	18,659	206	427	5,320	3,061	446	101	66,976

Schedule 1.3											
Allocated Revenue Requirement ($,000)											
Energy Related Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	32,006	1,140	2,940	24,814	535	622	5,963	9,130	420	162	77,734
ECAM Adjustment	3,970	141	365	3,078	66	77	740	1,133	52	20	9,643
Net Energy Costs	35,977	1,281	3,305	27,893	602	699	6,703	10,263	473	182	87,377
Distribution	2	0	0	2	0	0	0	1	0	0	6
Transmission	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0
General	139	5	13	107	2	3	26	40	2	1	337
Total Operating Expenses	36,118	1,286	3,317	28,002	604	702	6,729	10,303	474	183	87,720
Amortization											
Amortization Other	111	4	10	86	2	2	21	32	1	1	270
Amortization Plant And Equipm	125	4	12	97	2	2	23	36	2	1	304
Total Amortization	237	8	22	183	4	5	44	67	3	1	575
Total Operating Income	36,354	1,295	3,339	28,185	608	707	6,774	10,371	478	184	88,294
Financing Expenses											
Long-Term Debt	70	2	6	54	1	1	13	20	1	0	169
Short-Term Debt	3	0	0	2	0	0	1	1	0	0	7
Interest Charged To Constructi	(2)	(0)	(0)	(2)	(0)	(0)	(0)	(1)	(0)	(0)	(5)
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	71	3	6	55	1	1	13	20	1	0	171
Earnings before Income Taxes	36,425	1,297	3,346	28,240	609	708	6,787	10,391	478	185	88,466
Income Taxes	33	1	3	26	1	1	6	9	0	0	80
Net Earnings	71	3	7	55	1	1	13	20	1	0	173
Gross Revenue Requirement	36,529	1,301	3,355	28,321	611	710	6,806	10,420	480	185	88,719
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(1)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(2)
Net Revenue Requirement	36,528	1,301	3,355	28,320	611	710	6,806	10,420	480	185	88,716

Schedule 1.3											
Allocated Revenue Requirement ($,000)											
Site Related Revenue Requirement											
	Residenti al	Residenti al (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmeter ed	Total
Operating Expenses											
Energy Costs	71	9	3	9	2	0	0	0	6	0	101
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	71	9	3	9	2	0	0	0	6	0	101
Distribution	1,359	178	49	169	42	2	9	0	118	6	1,932
Transmission	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	587	77	21	74	18	1	3	0	47	3	831
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0
General	3,614	369	125	435	79	6	18	2	118	54	4,820
Total Operating Expenses	5,631	634	197	688	141	9	30	2	289	63	7,684
Amortization											
Amortization Other	34	4	1	4	1	0	0	0	3	0	48
Amortization Plant And Equipme	3,807	530	136	551	131	7	36	2	387	16	5,604
Total Amortization	3,842	535	137	556	132	7	36	2	389	16	5,652
Total Operating Income	9,473	1,168	335	1,243	273	16	66	4	678	79	13,336
Financing Expenses											
Long-Term Debt	3,109	431	111	475	106	6	31	1	282	13	4,567
Short-Term Debt	130	18	5	20	4	0	1	0	12	1	190
Interest Charged To Constructi	(96)	(13)	(3)	(15)	(3)	(0)	(1)	(0)	(9)	(0)	(140)
Amortization of Financing Costs	1	0	0	0	0	0	0	0	0	0	2
Total Financing Expenses	3,145	435	112	481	108	6	32	1	285	13	4,619
Earnings before Income Taxes	12,618	1,604	447	1,724	380	23	98	5	963	92	17,955
Income Taxes	1,468	203	52	224	50	3	15	1	133	6	2,156
Net Earnings	3,178	440	114	486	109	7	32	2	288	13	4,667
Gross Revenue Requirement	17,263	2,247	613	2,435	539	32	145	7	1,384	111	24,778
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(1,162)	(78)	(9)	(156)	(16)	(1)	(22)	(0)	(21)	(2)	(1,467)
Net Revenue Requirement	16,101	2,169	604	2,279	523	31	123	7	1,363	109	23,311

Schedule 1.4											
Allocated Revenue Requirement ($,000)											
Full Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	9,679	80	889	5,230	11	113	1,318	1,496	128	31	18,975
Purchased Power	49,060	1,358	4,506	34,640	599	843	8,428	11,258	646	221	111,560
Transmission	3,815	24	350	1,993	0	42	505	552	51	12	7,343
Substations	1,554	10	143	788	0	17	206	32	21	5	2,774
Primary Lines	7,751	769	456	2,441	229	60	740	62	400	30	12,939
Transformers	6,058	553	390	2,186	177	56	712	60	271	22	10,485
Secondary Lines	2,732	271	161	861	81	21	261	22	141	11	4,561
Service Lines	4,151	648	149	582	169	9	57	3	232	14	6,014
Meter Assets	1,028	136	37	366	38	5	32	2	0	0	1,645
Meter Reading	773	57	28	60	7	1	4	0	0	0	931
Billing	742	55	27	94	11	1	4	1	3	49	987
Remittance & Collection	620	46	22	79	10	1	3	0	4	3	787
Uncollectibles & Damage Claims	438	58	16	56	13	1	0	0	0	0	581
Service Connections	(298)	(23)	0	(16)	(2)	0	(0)	0	(0)	0	(338)
Late Payments	(490)	(13)	0	(101)	(5)	(1)	(20)	0	(1)	(1)	(632)
Lighting	0	0	0	0	0	0	0	0	393	0	393
Total	87,614	4,028	7,173	49,258	1,340	1,168	12,249	13,489	2,289	396	179,004
Demand Related Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	8,994	56	826	4,699	0	99	1,191	1,301	119	27	17,312
Purchased Power	13,216	82	1,214	6,851	0	146	1,750	1,033	175	40	24,506
Transmission	3,815	24	350	1,993	0	42	505	552	51	12	7,343
Substations	1,554	10	143	788	0	17	206	32	21	5	2,774
Primary Lines	3,185	167	293	1,862	89	53	718	62	35	8	6,469
Transformers	3,097	162	285	1,810	86	51	698	60	34	8	6,291
Secondary Lines	1,123	59	103	656	31	19	253	22	12	3	2,280
Service Lines	0	0	0	0	0	0	0	0	0	0	0
Meter Assets	0	0	0	0	0	0	0	0	0	0	0
Meter Reading	0	0	0	0	0	0	0	0	0	0	0
Billing	0	0	0	0	0	0	0	0	0	0	0
Remittance & Collection	0	0	0	0	0	0	0	0	0	0	0
Uncollectibles & Damage Claims	0	0	0	0	0	0	0	0	0	0	0
Service Connections	0	0	0	0	0	0	0	0	0	0	0
Late Payments	0	0	0	0	0	0	0	0	0	0	0
Lighting	0	0	0	0	0	0	0	0	0	0	0
Total	34,985	558	3,213	18,659	206	427	5,320	3,061	446	101	66,976

Schedule 1.4											
Allocated Revenue Requirement ($,000)											
Energy Related Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	685	24	63	531	11	13	128	195	9	3	1,663
Purchased Power	35,844	1,277	3,292	27,789	599	697	6,678	10,225	471	182	87,054
Transmission	0	0	0	0	0	0	0	0	0	0	0
Substations	0	0	0	0	0	0	0	0	0	0	0
Primary Lines	0	0	0	0	0	0	0	0	0	0	0
Transformers	0	0	0	0	0	0	0	0	0	0	0
Secondary Lines	0	0	0	0	0	0	0	0	0	0	0
Service Lines	0	0	0	0	0	0	0	0	0	0	0
Meter Assets	0	0	0	0	0	0	0	0	0	0	0
Meter Reading	0	0	0	0	0	0	0	0	0	0	0
Billing	0	0	0	0	0	0	0	0	0	0	0
Remittance & Collection	0	0	0	0	0	0	0	0	0	0	0
Uncollectibles & Damage Claims	0	0	0	0	0	0	0	0	0	0	0
Service Connections	0	0	0	0	0	0	0	0	0	0	0
Late Payments	0	0	0	0	0	0	0	0	0	0	0
Lighting	0	0	0	0	0	0	0	0	0	0	0
Total	36,528	1,301	3,355	28,320	611	710	6,806	10,420	480	185	88,716
Site Related Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0
Substations	0	0	0	0	0	0	0	0	0	0	0
Primary Lines	4,566	603	163	580	141	7	22	0	366	22	6,469
Transformers	2,960	391	106	376	91	5	14	0	237	14	4,194
Secondary Lines	1,610	212	58	204	50	3	8	0	129	8	2,280
Service Lines	4,151	648	149	582	169	9	57	3	232	14	6,014
Meter Assets	1,028	136	37	366	38	5	32	2	0	0	1,645
Meter Reading	773	57	28	60	7	1	4	0	0	0	931
Billing	742	55	27	94	11	1	4	1	3	49	987
Remittance & Collection	620	46	22	79	10	1	3	0	4	3	787
Uncollectibles & Damage Claims	438	58	16	56	13	1	0	0	0	0	581
Service Connections	(298)	(23)	0	(16)	(2)	0	(0)	0	(0)	0	(338)
Late Payments	(490)	(13)	0	(101)	(5)	(1)	(20)	0	(1)	(1)	(632)
Lighting	0	0	0	0	0	0	0	0	393	0	393
Total	16,101	2,169	604	2,279	523	31	123	7	1,363	109	23,311

Schedule 2.0											
Allocators by Function											
Allocators											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	51.0 %	0.4 %	4.7 %	27.6 %	0.1 %	0.6 %	6.9 %	7.9 %	0.7 %	0.2 %	100.0 %
Purchased Power	44.0 %	1.2 %	4.0 %	31.1 %	0.5 %	0.8 %	7.6 %	10.1 %	0.6 %	0.2 %	100.0 %
Transmission	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %
Substations	56.0 %	0.3 %	5.1 %	28.4 %	0.0 %	0.6 %	7.4 %	1.1 %	0.7 %	0.2 %	100.0 %
Primary Lines	59.9 %	5.9 %	3.5 %	18.9 %	1.8 %	0.5 %	5.7 %	0.5 %	3.1 %	0.2 %	100.0 %
Transformers	57.8 %	5.3 %	3.7 %	20.8 %	1.7 %	0.5 %	6.8 %	0.6 %	2.6 %	0.2 %	100.0 %
Secondary Lines	59.9 %	5.9 %	3.5 %	18.9 %	1.8 %	0.5 %	5.7 %	0.5 %	3.1 %	0.2 %	100.0 %
Service Lines	69.0 %	10.8 %	2.5 %	9.7 %	2.8 %	0.1 %	0.9 %	0.1 %	3.9 %	0.2 %	100.0 %
Meter Assets	62.5 %	8.3 %	2.2 %	22.3 %	2.3 %	0.3 %	2.0 %	0.1 %	0.0 %	0.0 %	100.0 %
Meter Reading	83.1 %	6.1 %	3.0 %	6.4 %	0.8 %	0.1 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %
Billing	75.2 %	5.5 %	2.7 %	9.5 %	1.2 %	0.1 %	0.4 %	0.1 %	0.3 %	4.9 %	100.0 %
Remittance & Collection	78.7 %	5.8 %	2.8 %	10.0 %	1.2 %	0.1 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %
Uncollectibles & Damage Claims	75.4 %	9.9 %	2.7 %	9.6 %	2.3 %	0.1 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Service Connections	88.0 %	6.7 %	0.0 %	4.6 %	0.5 %	0.0 %	0.1 %	0.0 %	0.0 %	0.0 %	100.0 %
Late Payments	77.5 %	2.0 %	0.0 %	16.0 %	0.9 %	0.2 %	3.1 %	0.0 %	0.2 %	0.1 %	100.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %
Demand Allocators, Isolated (%)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %
Purchased Power	53.9 %	0.3 %	5.0 %	28.0 %	0.0 %	0.6 %	7.1 %	4.2 %	0.7 %	0.2 %	100.0 %
Transmission	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %
Substations	56.0 %	0.3 %	5.1 %	28.4 %	0.0 %	0.6 %	7.4 %	1.1 %	0.7 %	0.2 %	100.0 %
Primary Lines	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %
Transformers	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %
Secondary Lines	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Uncollectibles & Damage Claims	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connections	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Late Payments	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %

Schedule 2.0											
Allocators by Function											
Energy Allocators, Isolated (%)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %
Purchased Power	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %
Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Substations	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Primary Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Transformers	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Secondary Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Uncollectibles & Damage Claims	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connections	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Late Payments	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Site Allocators, Isolated (%)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Purchased Power	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Substations	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Primary Lines	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Transformers	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Secondary Lines	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Service Lines	69.0 %	10.8 %	2.5 %	9.7 %	2.8 %	0.1 %	0.9 %	0.1 %	3.9 %	0.2 %	100.0 %
Meter Assets	62.5 %	8.3 %	2.2 %	22.3 %	2.3 %	0.3 %	2.0 %	0.1 %	0.0 %	0.0 %	100.0 %
Meter Reading	83.1 %	6.1 %	3.0 %	6.4 %	0.8 %	0.1 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %
Billing	75.2 %	5.5 %	2.7 %	9.5 %	1.2 %	0.1 %	0.4 %	0.1 %	0.3 %	4.9 %	100.0 %
Remittance & Collection	78.7 %	5.8 %	2.8 %	10.0 %	1.2 %	0.1 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %
Uncollectibles & Damage Claims	75.4 %	9.9 %	2.7 %	9.6 %	2.3 %	0.1 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Service Connections	88.0 %	6.7 %	0.0 %	4.6 %	0.5 %	0.0 %	0.1 %	0.0 %	0.0 %	0.0 %	100.0 %
Late Payments	77.5 %	2.0 %	0.0 %	16.0 %	0.9 %	0.2 %	3.1 %	0.0 %	0.2 %	0.1 %	100.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %

Schedule 2.1											
Allocators											
Allocators											
	Residenti al	Residenti al (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmeter ed	Total
1CP - Input	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %
1CP - Input Firm	56.2 %	0.3 %	5.2 %	28.9 %	0.0 %	0.6 %	7.4 %	0.4 %	0.7 %	0.2 %	100.0 %
1CP - Transmission	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %
1CP - Distribution Primary	56.0 %	0.3 %	5.1 %	28.4 %	0.0 %	0.6 %	7.4 %	1.1 %	0.7 %	0.2 %	100.0 %
NCP - Distribution Primary	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %
NCP - Distribution Secondary	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %
Energy - Input	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %
Sites	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Sites - Distribution Primary	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Sites - Distribution Secondary	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Sites - Mass Market	75.4 %	9.9 %	2.7 %	9.6 %	2.3 %	0.1 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Service Lines	69.0 %	10.8 %	2.5 %	9.7 %	2.8 %	0.1 %	0.9 %	0.1 %	3.9 %	0.2 %	100.0 %
Meter Assets	62.5 %	8.3 %	2.2 %	22.3 %	2.3 %	0.3 %	2.0 %	0.1 %	0.0 %	0.0 %	100.0 %
Meter Reading	83.1 %	6.1 %	3.0 %	6.4 %	0.8 %	0.1 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %
Billing	75.2 %	5.5 %	2.7 %	9.5 %	1.2 %	0.1 %	0.4 %	0.1 %	0.3 %	4.9 %	100.0 %
Remittance & Collection	78.7 %	5.8 %	2.8 %	10.0 %	1.2 %	0.1 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %
Service Connection Revenue	88.0 %	6.7 %	0.0 %	4.6 %	0.5 %	0.0 %	0.1 %	0.0 %	0.0 %	0.0 %	100.0 %
Penalty Revenue	77.5 %	2.0 %	0.0 %	16.0 %	0.9 %	0.2 %	3.1 %	0.0 %	0.2 %	0.1 %	100.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %
MECL Generation	51.0 %	0.4 %	4.7 %	27.6 %	0.1 %	0.6 %	6.9 %	7.9 %	0.7 %	0.2 %	100.0 %
MECL Purchases	44.0 %	1.2 %	4.0 %	31.1 %	0.5 %	0.8 %	7.6 %	10.1 %	0.6 %	0.2 %	100.0 %
Primary System	59.9 %	5.9 %	3.5 %	18.9 %	1.8 %	0.5 %	5.7 %	0.5 %	3.1 %	0.2 %	100.0 %
Distribution Transformers	57.8 %	5.3 %	3.7 %	20.8 %	1.7 %	0.5 %	6.8 %	0.6 %	2.6 %	0.2 %	100.0 %
Secondary System	59.9 %	5.9 %	3.5 %	18.9 %	1.8 %	0.5 %	5.7 %	0.5 %	3.1 %	0.2 %	100.0 %

Schedule 2.1												
Allocators												
Demand Allocators, Isolated (%)												
	Residenti al	Residenti al (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmeter ed	Total	Weight
1CP - Input	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %	100.0 %
1CP - Input Firm	56.2 %	0.3 %	5.2 %	28.9 %	0.0 %	0.6 %	7.4 %	0.4 %	0.7 %	0.2 %	100.0 %	100.0 %
1CP - Transmission	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %	100.0 %
1CP - Distribution Primary	56.0 %	0.3 %	5.1 %	28.4 %	0.0 %	0.6 %	7.4 %	1.1 %	0.7 %	0.2 %	100.0 %	100.0 %
NCP - Distribution Primary	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	100.0 %
NCP - Distribution Secondary	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	100.0 %
Energy - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Mass Market	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connection Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Penalty Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
MECL Generation	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %	91.2 %
MECL Purchases	53.9 %	0.3 %	5.0 %	28.0 %	0.0 %	0.6 %	7.1 %	4.2 %	0.7 %	0.2 %	100.0 %	22.0 %
Primary System	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	50.0 %
Distribution Transformers	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	60.0 %
Secondary System	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	50.0 %

Schedule 2.1												
Allocators												
Energy Allocators, Isolated (%)												
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total	Weight
1CP - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Input Firm	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Energy - Input	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %	100.0 %
Sites	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Mass Market	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connection Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Penalty Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
MECL Generation	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %	8.8 %
MECL Purchases	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %	78.0 %
Primary System	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Distribution Transformers	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Secondary System	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %

Schedule 2.1												
Allocators												
Site Allocators, Isolated (%)												
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total	Weight
1CP - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Input Firm	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Energy - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	100.0 %
Sites - Distribution Primary	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	100.0 %
Sites - Distribution Secondary	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	100.0 %
Sites - Mass Market	75.4 %	9.9 %	2.7 %	9.6 %	2.3 %	0.1 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	100.0 %
Service Lines	69.0 %	10.8 %	2.5 %	9.7 %	2.8 %	0.1 %	0.9 %	0.1 %	3.9 %	0.2 %	100.0 %	100.0 %
Meter Assets	62.5 %	8.3 %	2.2 %	22.3 %	2.3 %	0.3 %	2.0 %	0.1 %	0.0 %	0.0 %	100.0 %	100.0 %
Meter Reading	83.1 %	6.1 %	3.0 %	6.4 %	0.8 %	0.1 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %	100.0 %
Billing	75.2 %	5.5 %	2.7 %	9.5 %	1.2 %	0.1 %	0.4 %	0.1 %	0.3 %	4.9 %	100.0 %	100.0 %
Remittance & Collection	78.7 %	5.8 %	2.8 %	10.0 %	1.2 %	0.1 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %	100.0 %
Service Connection Revenue	88.0 %	6.7 %	0.0 %	4.6 %	0.5 %	0.0 %	0.1 %	0.0 %	0.0 %	0.0 %	100.0 %	100.0 %
Penalty Revenue	77.5 %	2.0 %	0.0 %	16.0 %	0.9 %	0.2 %	3.1 %	0.0 %	0.2 %	0.1 %	100.0 %	100.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %	100.0 %
MECL Generation	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
MECL Purchases	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Primary System	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	50.0 %
Distribution Transformers	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	40.0 %
Secondary System	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	50.0 %

Schedule 2.2											
Allocator Assumptions											
Site Allocator Weighting Assumptions											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Service Lines	333	394	333	368	441	441	947	3,400	232	232	6,657
Meter Assets	131	131	131	367	157	421	850	4,259	0	0	6,449
Meter Reading	12	7	12	7	4	12	12	60	0	0	126
Billing	12	7	12	12	6	12	12	300	1	300	373
Remittance & Collection	12	7	12	12	6	12	12	12	1	12	85
Lighting & Unmetered Equivalence									0.40	0.40	
Base Allocators											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
1CP - Input (kW)	119,190	738	10,948	62,272	0	1,319	15,778	17,241	1,579	359	229,423
1CP - Input Firm (kW)	119,190	738	10,948	61,266	0	1,319	15,778	908	1,579	359	212,085
1CP - Transmission (kW)	115,674	716	10,625	60,434	0	1,280	15,313	16,732	1,532	349	222,654
1CP - Distribution Primary (kW)	115,674	716	10,625	58,638	0	1,280	15,313	2,364	1,532	349	206,490
NCP - Distribution Primary (kW)	142,428	7,449	13,082	83,244	3,958	2,349	32,095	2,770	1,552	349	289,275
NCP - Distribution Secondary (kW)	135,146	7,068	12,413	78,987	3,755	2,229	30,454	2,628	1,473	331	274,485
Energy - Input (MWh)	515,510	18,359	47,351	399,673	8,620	10,023	96,049	147,055	6,772	2,612	1,252,023
Sites	55,530	7,328	1,987	7,049	1,711	87	268	4	4,447	269	78,679
Sites - Distribution Primary	55,530	7,328	1,987	7,048	1,711	87	268	2	4,447	269	78,676
Sites - Distribution Secondary	55,530	7,328	1,987	7,048	1,711	87	268	0	4,447	269	78,674
Sites - Mass Market	55,530	7,328	1,987	7,049	1,711	87	0	0	0	0	73,691
Service Lines ($,000)	18,491	2,887	662	2,591	755	38	254	14	1,033	62	26,787
Meter Assets ($,000)	7,274	960	260	2,590	269	37	228	17	0	0	11,635
Meter Reading (Weighted Sites x :	666	49	24	52	6	1	3	0	0	0	802
Billing (Weighted Sites x 1000)	666	49	24	85	10	1	3	1	3	44	886
Remittance & Collection (Weighted	666	49	24	85	10	1	3	0	4	3	846
Service Connection Revenue ($,00	427	32	0	22	3	0	1	0	0	0	485
Penalty Revenue ($,000)	490	13	0	101	5	1	20	0	1	1	632
Lighting Direct Assign	0	0	0	0	0	0	0	0	1	0	1
Sales Data											
Billing Demand (kW * 12 Months)	N/A	N/A	N/A	923,095	11,272	21,656	295,831	252,201	N/A	1,381	1,505,435
Peak metered demand	N/A	N/A	N/A	79,642	2,296	1,941	28,893	22,379	N/A	N/A	135,149
Sales (MWh)	480,053	17,210	44,094	369,228	7,962	9,421	88,930	142,152	6,236	2,405	1,167,691
Average Bills per Month	55,530	7,328	1,987	7,049	1,711	87	268	4	3,064	146	77,173
Revenue ($,000)	83,555	4,090	6,052	59,134	1,598	1,433	12,097	13,813	2,470	419	184,662
Lighting & Unmetered Fixtures									11,117	672	

Schedule 2.3							
Assumptions to Split Residential Rate Classes							
Used in Cost Allocation Model:	STATUS QUO RATE CLASSES				SPLIT RESIDENTIAL RATE CLAS		
Site Allocator Weighting Assumptions							
	Residential	Residential (S)	Farm		Residential	Residential (S)	Farm
Service Lines	333	394	0		333	394	333
Meter Assets	131	131	0		131	131	131
Meter Reading	12	7	0		12	7	12
Billing	12	7	0		12	7	12
Remittance & Collection	12	7	0		12	7	12
Base Allocators							
	Residential	Residential (S)	Farm		Residential	Residential (S)	Farm
1CP - Input (kW)	130,138	738	0		119,190	738	10,948
1CP - Input Firm (kW)	130,138	738	0		119,190	738	10,948
1CP - Transmission (kW)	126,299	716	0		115,674	716	10,625
1CP - Distribution Primary (kW)	126,299	716	0		115,674	716	10,625
NCP - Distribution Primary (kW)	155,510	7,449	0		142,428	7,449	13,082
NCP - Distribution Secondary (kW)	147,559	7,068	0		135,146	7,068	12,413
Energy - Input (MWh)	562,860	18,359	0		515,510	18,359	47,351
Sites							
Sites - Distribution Primary							
Sites - Distribution Secondary							
Sites - Mass Market							
Service Lines ($,000)							
Meter Assets ($,000)							
Meter Reading (Weighted Sites)							
Billing (Weighted Sites)							
Remittance & Collection (Weighted Sites)							
Service Connection Revenue ($,00	427	32	0		412	32	15
Penalty Revenue ($,000)	490	13	0		473	13	17
Lighting Direct Assign	0	0	0		0	0	0
Sales Data							
Billing Demand (kW * 12 Months)	N/A	N/A	N/A		N/A	N/A	N/A
Peak metered demand	N/A	N/A	N/A		N/A	N/A	N/A
Sales (MWh)	524,147	17,210	0		480,053	17,210	44,094
Sites	57,517	7,328	0		55,530	7,328	1,987
Revenue ($,000)	89,607	4,090	0		83,555	4,090	6,052

Schedule 2.4					
Classification Assumptions					
Allocator	Demand Related	Energy Related	Site Related	Total	
1CP - Input	100 %	0 %	0 %	100 %	
1CP - Input Firm	100 %	0 %	0 %	100 %	
1CP - Transmission	100 %	0 %	0 %	100 %	
1CP - Distribution Primary	100 %	0 %	0 %	100 %	
NCP - Distribution Primary	100 %	0 %	0 %	100 %	
NCP - Distribution Secondary	100 %	0 %	0 %	100 %	
Energy - Input	0 %	100 %	0 %	100 %	
Sites	0 %	0 %	100 %	100 %	
Sites - Distribution Primary	0 %	0 %	100 %	100 %	
Sites - Distribution Secondary	0 %	0 %	100 %	100 %	
Sites - Mass Market	0 %	0 %	100 %	100 %	
Service Lines	0 %	0 %	100 %	100 %	
Meter Assets	0 %	0 %	100 %	100 %	
Meter Reading	0 %	0 %	100 %	100 %	
Billing	0 %	0 %	100 %	100 %	
Remittance & Collection	0 %	0 %	100 %	100 %	
Service Connection Revenue	0 %	0 %	100 %	100 %	
Penalty Revenue	0 %	0 %	100 %	100 %	
Lighting Direct Assign	0 %	0 %	100 %	100 %	
MECL Generation	91 %	9 %	0 %	100 %	
MECL Purchases	22 %	78 %	0 %	100 %	
Primary System	50 %	0 %	50 %	100 %	
Distribution Transformers	60 %	0 %	40 %	100 %	
Secondary System	50 %	0 %	50 %	100 %	
Blended Allocator Assumptions					
	MECL Generation	MECL Purchases	Primary System	Distribution Transformers	Secondary System
1CP - Input	91 %	12 %			
1CP - Input Firm		10 %			
1CP - Transmission					
1CP - Distribution Primary					
NCP - Distribution Primary			50 %		
NCP - Distribution Secondary				60 %	50 %
Energy - Input	9 %	78 %			
Sites					
Sites - Distribution Primary			50 %		
Sites - Distribution Secondary				40 %	50 %
Total	100 %	100 %	100 %	100 %	100 %
Energy Cost Classification					
Energy Costs ($,000)	Generation	Purchased Power			
Demand Related	5,725	21,728			
Total	6,275	98,913			

Schedule 2.5	
Allocator by Function Assumptions	
Function	Allocator
Generation	MECL Generation
Purchased Power	MECL Purchases
Transmission	1CP - Transmission
Substations	1CP - Distribution Primary
Primary Lines	Primary System
Transformers	Distribution Transformers
Secondary Lines	Secondary System
Service Lines	Service Lines
Meter Assets	Meter Assets
Meter Reading	Meter Reading
Billing	Billing
Remittance & Collection	Remittance & Collection
Uncollectibles & Damage Claims	Sites - Mass Market
Service Connections	Service Connection Revenue
Late Payments	Penalty Revenue
Lighting	Lighting Direct Assign

Schedule 3.0
Functionalized Revenue Requirement, Summary

Revenue Requirement ($,000)

	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	6,275	98,913	1,209	207	72	71	70	2	0	0	0	0	0	0	0	0	106,818
ECAM Adjustment	0	12,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,358
Net Energy Costs	6,275	111,270	1,209	207	72	71	70	2	0	0	0	0	0	0	0	0	119,176
Distribution	65	0	65	258	1,449	1,053	497	357	0	155	0	0	0	0	0	26	3,925
Transmission	0	0	922	0	0	0	0	0	0	0	0	0	0	0	0	0	922
Transmission and Distribution -	0	0	0	212	886	601	295	0	0	0	0	0	0	0	0	0	1,994
Transmission - OATT	0	0	172	0	0	0	0	0	0	0	0	0	0	0	0	0	172
General	2,557	144	1,324	506	1,281	1,285	525	295	72	696	929	700	562	129	0	20	11,025
Total Operating Expenses	8,897	111,414	3,693	1,182	3,687	3,009	1,387	654	73	850	929	700	562	129	0	46	137,214
Amortization																	
Amortization Other	93	336	143	18	37	40	15	2	0	4	0	0	0	0	0	0	688
Amortization Plant And Equipme	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761
Total Amortization	3,304	365	1,920	608	3,240	2,359	1,129	1,919	367	38	19	30	6	6	0	138	15,450
Total Operating Income	12,201	111,780	5,612	1,791	6,927	5,369	2,516	2,574	439	889	948	730	568	135	0	184	152,663
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	2,718	(88)	1,429	395	2,585	2,053	878	1,380	484	17	16	23	5	5	0	84	11,983
Short-Term Debt	113	(4)	60	16	108	86	37	58	20	1	1	1	0	0	0	4	500
Interest Charged To Constructio	(84)	3	(44)	(12)	(79)	(63)	(27)	(42)	(15)	(1)	(0)	(1)	(0)	(0)	0	(3)	(368)
Amortization of Financing Costs	1	(0)	1	0	1	1	0	1	0	0	0	0	0	0	0	0	5
Total Financing Expenses	2,749	(89)	1,445	399	2,614	2,076	888	1,396	489	17	16	24	5	5	0	85	12,119
Earnings before Income Taxes	14,950	111,691	7,057	2,190	9,541	7,445	3,404	3,970	928	906	964	754	573	140	0	269	164,782
Income Taxes	1,283	(42)	675	186	1,220	969	415	652	228	8	7	11	3	2	0	40	5,658
Net Earnings	2,778	(90)	1,460	403	2,641	2,098	897	1,411	494	17	16	24	5	5	0	86	12,246
Gross Revenue Requirement	19,011	111,559	9,192	2,779	13,403	10,513	4,716	6,032	1,651	931	988	789	581	147	0	394	182,686
OATT Revenue	0	0	(1,830)	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,830)
Other Revenue	(36)	1	(19)	(5)	(464)	(27)	(155)	(18)	(6)	(0)	(1)	(1)	(0)	(485)	(632)	(1)	(1,852)
Net Revenue Requirement	18,975	111,560	7,343	2,774	12,939	10,485	4,561	6,014	1,645	931	987	787	581	(338)	(632)	393	179,004

Schedule 3.0
Functionalized Revenue Requirement, Summary

Revenue Requirement, Demand Related ($,000)

	Generati on	Purchase d Power	Transmis sion	Substatio ns	Primary Lines	Transfor mers	Secondar y Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittan ce & Collection	Uncollecti bles & Damage Claims	Service Connecti ons	Late Payment s	Lighting	Total
Operating Expenses																	
Energy Costs	5,725	21,728	1,209	207	36	42	35	0	0	0	0	0	0	0	0	0	28,982
ECAM Adjustment	0	2,715	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,715
Net Energy Costs	5,725	24,443	1,209	207	36	42	35	0	0	0	0	0	0	0	0	0	31,697
Distribution	60	0	65	258	724	632	249	0	0	0	0	0	0	0	0	0	1,987
Transmission	0	0	922	0	0	0	0	0	0	0	0	0	0	0	0	0	922
Transmission and Distribution -	0	0	0	212	443	360	148	0	0	0	0	0	0	0	0	0	1,163
Transmission - OATT	0	0	172	0	0	0	0	0	0	0	0	0	0	0	0	0	172
General	2,333	32	1,324	506	640	771	262	0	0	0	0	0	0	0	0	0	5,869
Total Operating Expenses	8,118	24,474	3,693	1,182	1,844	1,806	694	0	0	0	0	0	0	0	0	0	41,810
Amortization																	
Amortization Other	85	74	143	18	19	24	8	0	0	0	0	0	0	0	0	0	370
Amortization Plant And Equipm	2,930	6	1,777	590	1,601	1,391	557	0	0	0	0	0	0	0	0	0	8,853
Total Amortization	3,015	80	1,920	608	1,620	1,416	564	0	0	0	0	0	0	0	0	0	9,223
Total Operating Income	11,132	24,555	5,612	1,791	3,464	3,221	1,258	0	0	0	0	0	0	0	0	0	51,033
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	2,480	(19)	1,429	395	1,292	1,232	439	0	0	0	0	0	0	0	0	0	7,247
Short-Term Debt	103	(1)	60	16	54	51	18	0	0	0	0	0	0	0	0	0	302
Interest Charged To Constructi	(76)	1	(44)	(12)	(40)	(38)	(14)	0	0	0	0	0	0	0	0	0	(223)
Amortization of Financing Costs	1	(0)	1	0	1	1	0	0	0	0	0	0	0	0	0	0	3
Total Financing Expenses	2,508	(20)	1,445	399	1,307	1,246	444	0	0	0	0	0	0	0	0	0	7,329
Earnings before Income Taxes	13,640	24,535	7,057	2,190	4,771	4,467	1,702	0	0	0	0	0	0	0	0	0	58,362
Income Taxes	1,171	(9)	675	186	610	582	207	0	0	0	0	0	0	0	0	0	3,422
Net Earnings	2,534	(20)	1,460	403	1,321	1,259	449	0	0	0	0	0	0	0	0	0	7,406
Gross Revenue Requirement	17,345	24,506	9,192	2,779	6,702	6,308	2,358	0	0	0	0	0	0	0	0	0	69,189
OATT Revenue	0	0	(1,830)	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,830)
Other Revenue	(33)	0	(19)	(5)	(232)	(16)	(78)	0	0	0	0	0	0	0	0	0	(384)
Net Revenue Requirement	17,312	24,506	7,343	2,774	6,469	6,291	2,280	0	0	0	0	0	0	0	0	0	66,976

Schedule 3.0

Functionalized Revenue Requirement, Summary

Revenue Requirement, Energy Related ($,000)

	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	550	77,185	0	0	0	0	0	0	0	0	0	0	0	0	0	0	77,734
ECAM Adjustment	0	9,643	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9,643
Net Energy Costs	550	86,828	0	0	0	0	0	0	0	0	0	0	0	0	0	0	87,377
Distribution	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	224	112	0	0	0	0	0	0	0	0	0	0	0	0	0	0	337
Total Operating Expenses	780	86,940	0	0	0	0	0	0	0	0	0	0	0	0	0	0	87,720
Amortization																	
Amortization Other	8	262	0	0	0	0	0	0	0	0	0	0	0	0	0	0	270
Amortization Plant And Equipme	281	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	304
Total Amortization	290	285	0	0	0	0	0	0	0	0	0	0	0	0	0	0	575
Total Operating Income	1,069	87,225	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88,294
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	238	(69)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	169
Short-Term Debt	10	(3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
Interest Charged To Constructi	(7)	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(5)
Amortization of Financing Costs	0	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	241	(70)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	171
Earnings before Income Taxes	1,310	87,156	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88,466
Income Taxes	112	(32)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	80
Net Earnings	243	(70)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	173
Gross Revenue Requirement	1,666	87,053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88,719
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(3)	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(2)
Net Revenue Requirement	1,663	87,054	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88,716

Schedule 3.0																	
Functionalized Revenue Requirement, Summary																	
Revenue Requirement, Site Related ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	0	0	0	0	36	28	35	2	0	0	0	0	0	0	0	0	101
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	0	0	0	0	36	28	35	2	0	0	0	0	0	0	0	0	101
Distribution	0	0	0	0	724	421	249	357	0	155	0	0	0	0	0	26	1,932
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	443	240	148	0	0	0	0	0	0	0	0	0	831
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	640	514	262	295	72	696	929	700	562	129	0	20	4,820
Total Operating Expenses	0	0	0	0	1,844	1,204	694	654	73	850	929	700	562	129	0	46	7,684
Amortization																	
Amortization Other	0	0	0	0	19	16	8	2	0	4	0	0	0	0	0	0	48
Amortization Plant And Equipm	0	0	0	0	1,601	928	557	1,918	367	34	19	30	6	6	0	138	5,604
Total Amortization	0	0	0	0	1,620	944	564	1,919	367	38	19	30	6	6	0	138	5,652
Total Operating Income	0	0	0	0	3,464	2,147	1,258	2,574	439	889	948	730	568	135	0	184	13,336
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	1,292	821	439	1,380	484	17	16	23	5	5	0	84	4,567
Short-Term Debt	0	0	0	0	54	34	18	58	20	1	1	1	0	0	0	4	190
Interest Charged To Constructi	0	0	0	0	(40)	(25)	(14)	(42)	(15)	(1)	(0)	(1)	(0)	(0)	0	(3)	(140)
Amortization of Financing Costs	0	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0	2
Total Financing Expenses	0	0	0	0	1,307	831	444	1,396	489	17	16	24	5	5	0	85	4,619
Earnings before Income Taxes	0	0	0	0	4,771	2,978	1,702	3,970	928	906	964	754	573	140	0	269	17,955
Income Taxes	0	0	0	0	610	388	207	652	228	8	7	11	3	2	0	40	2,156
Net Earnings	0	0	0	0	1,321	839	449	1,411	494	17	16	24	5	5	0	86	4,667
Gross Revenue Requirement	0	0	0	0	6,702	4,205	2,358	6,032	1,651	931	988	789	581	147	0	394	24,778
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	(232)	(11)	(78)	(18)	(6)	(0)	(1)	(1)	(0)	(485)	(632)	(1)	(1,467)
Net Revenue Requirement	0	0	0	0	6,469	4,194	2,280	6,014	1,645	931	987	787	581	(338)	(632)	393	23,311

Schedule 3.1																	
Functionalized Revenue Requirement																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	5,725	98,775	748	0	0	0	0	0	0	0	0	0	0	0	0	0	105,248
ECAM Adjustment	0	12,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,358
Net Energy Costs	5,725	111,133	748	0	0	0	0	0	0	0	0	0	0	0	0	0	117,606
Distribution	0	0	0	74	0	419	0	0	0	155	0	0	0	0	0	0	648
Transmission	0	0	922	0	0	0	0	0	0	0	0	0	0	0	0	0	922
Transmission and Distribution -	0	0	0	96	0	0	0	0	0	0	0	0	0	0	0	0	96
Transmission - OATT	0	0	172	0	0	0	0	0	0	0	0	0	0	0	0	0	172
General	0	0	0	0	0	0	0	0	0	376	0	0	308	0	0	0	684
Total Operating Expenses	5,725	111,133	1,842	171	0	419	0	0	0	531	0	0	308	0	0	0	120,128
Amortization																	
Amortization Other	0	329	0	0	0	0	0	0	0	0	0	0	0	0	0	0	329
Amortization Plant And Equipm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	329	0	0	0	0	0	0	0	0	0	0	0	0	0	0	329
Total Operating Income	5,725	111,462	1,842	171	0	419	0	0	0	531	0	0	308	0	0	0	120,457
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	5,725	111,462	1,842	171	0	419	0	0	0	531	0	0	308	0	0	0	120,457
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	5,725	111,462	1,842	171	0	419	0	0	0	531	0	0	308	0	0	0	120,457
OATT Revenue	0	0	(1,830)	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,830)
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	(485)	(632)	0	(1,117)
Net Revenue Requirement	5,725	111,462	12	171	0	419	0	0	0	531	0	0	308	(485)	(632)	0	117,510

Schedule 3.1																	
Functionalized Revenue Requirement																	
For Allocation (First)																	
	ECC	SCADA	Environmental	Primary & Secondary	Call Center	Labour	Customer Service	Finance Labour	Finance Admin	Head Office	T&D Plant	Right of Way Amortization	Distribution Lines	Distribution Network	Total Plant		Total
Operating Expenses																	
Energy Costs	825	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	836
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	825	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	836
Distribution	0	261	0	0	0	0	0	0	0	0	0	0	1,082	1,934	0	0	3,277
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	1,898	0	0	1,898
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	7	0	882	5,764	626	408	851	149	383	0	0	0	46	0	9,115
Total Operating Expenses	825	261	7	0	882	5,764	626	408	851	149	393	0	1,082	3,832	46	0	15,125
Amortization																	
Amortization Other	0	0	0	0	0	248	0	0	0	0	0	112	0	0	0	0	359
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	248	0	0	0	0	0	112	0	0	0	0	359
Total Operating Income	825	261	7	0	882	6,012	626	408	851	149	393	112	1,082	3,832	46	0	15,485
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	825	261	7	0	882	6,012	626	408	851	149	393	112	1,082	3,832	46	0	15,485
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	825	261	7	0	882	6,012	626	408	851	149	393	112	1,082	3,832	46	0	15,485
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	(573)	0	0	0	0	0	(6)	0	0	0	0	0	0	(579)
Net Revenue Requirement	825	261	7	(573)	882	6,012	626	408	851	143	393	112	1,082	3,832	46	0	14,906

Schedule 3.1
Functionalized Revenue Requirement

For Allocation (Second)

	Amortization	G&T Rate Base	Rate Base Excluding WC	Rate Base													Total
Operating Expenses																	
Energy Costs	0	734	0	0	0	0	0	0	0	0	0	0	0	0	0	0	734
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	0	734	0	0	0	0	0	0	0	0	0	0	0	0	0	0	734
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	1,227	0	0	0	0	0	0	0	0	0	0	0	0	0	1,227
Total Operating Expenses	0	734	1,227	0	0	0	0	0	0	0	0	0	0	0	0	0	1,961
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	14,761	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14,761
Total Amortization	14,761	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14,761
Total Operating Income	14,761	734	1,227	0	0	0	0	0	0	0	0	0	0	0	0	0	16,722
Financing Expenses																	
Long-Term Debt	0	0	0	11,983	0	0	0	0	0	0	0	0	0	0	0	0	11,983
Short-Term Debt	0	0	0	500	0	0	0	0	0	0	0	0	0	0	0	0	500
Interest Charged To Constructi	0	0	0	(368)	0	0	0	0	0	0	0	0	0	0	0	0	(368)
Amortization of Financing Costs	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	5
Total Financing Expenses	0	0	0	12,119	0	0	0	0	0	0	0	0	0	0	0	0	12,119
Earnings before Income Taxes	14,761	734	1,227	12,119	0	0	0	0	0	0	0	0	0	0	0	0	28,841
Income Taxes	0	0	0	5,658	0	0	0	0	0	0	0	0	0	0	0	0	5,658
Net Earnings	0	0	0	12,246	0	0	0	0	0	0	0	0	0	0	0	0	12,246
Gross Revenue Requirement	14,761	734	1,227	30,023	0	0	0	0	0	0	0	0	0	0	0	0	46,745
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	(157)	0	0	0	0	0	0	0	0	0	0	0	0	(157)
Net Revenue Requirement	14,761	734	1,227	29,866	0	0	0	0	0	0	0	0	0	0	0	0	46,588

Schedule 3.1

Functionalized Revenue Requirement

Required Allocation Factors

	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Environmental	50.0 %	0.0 %	0.0 %	2.0 %	0.0 %	48.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Customer Service	0.0 %	0.0 %	2.8 %	0.0 %	1.8 %	1.8 %	1.8 %	0.0 %	0.0 %	27.8 %	11.0 %	22.0 %	25.5 %	5.5 %	0.0 %	0.0 %	100.0 %
Finance Labour	10.7 %	0.8 %	9.1 %	2.8 %	9.4 %	8.1 %	3.5 %	4.0 %	0.7 %	0.5 %	28.6 %	21.4 %	0.0 %	0.0 %	0.0 %	0.3 %	100.0 %
Finance Admin	5.3 %	0.4 %	4.6 %	1.4 %	4.7 %	4.1 %	1.7 %	2.0 %	0.4 %	0.2 %	64.3 %	10.7 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Head Office	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.2 %	4.0 %	26.0 %	17.7 %	8.8 %	17.6 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Right of Way Amortization	0.0 %	0.0 %	91.9 %	0.0 %	4.0 %	2.7 %	1.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Total Plant	21.6 %	0.1 %	16.2 %	3.3 %	20.6 %	14.3 %	7.0 %	13.0 %	2.5 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.9 %	100.0 %
Amortization	21.8 %	0.2 %	12.0 %	4.0 %	21.7 %	15.7 %	7.5 %	13.0 %	2.5 %	0.2 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.9 %	100.0 %
G&T Rate Base	65.5 %	0.0 %	34.5 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Rate Base Excluding WC	22.9 %	(2.0)%	12.1 %	3.3 %	21.9 %	17.4 %	7.4 %	11.7 %	4.1 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Rate Base	22.7 %	(0.7)%	11.9 %	3.3 %	21.6 %	17.1 %	7.3 %	11.5 %	4.0 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %

Schedule 3.1																	
Functionalized Revenue Requirement																	
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	69	138	209	207	72	71	70	2	0	0	0	0	0	0	0	0	836
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	69	138	209	207	72	71	70	2	0	0	0	0	0	0	0	0	836
Distribution	65	0	65	183	1,449	634	497	357	0	0	0	0	0	0	0	26	3,277
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	116	886	601	295	0	0	0	0	0	0	0	0	0	1,898
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	2,276	169	1,176	465	1,013	1,072	434	152	22	318	928	698	254	129	0	11	9,115
Total Operating Expenses	2,410	306	1,450	971	3,419	2,377	1,296	511	22	318	928	698	254	129	0	37	15,125
Amortization																	
Amortization Other	93	7	143	18	37	40	15	2	0	4	0	0	0	0	0	0	359
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	93	7	143	18	37	40	15	2	0	4	0	0	0	0	0	0	359
Total Operating Income	2,502	313	1,593	989	3,457	2,418	1,312	513	22	322	928	698	254	129	0	37	15,485
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	2,502	313	1,593	989	3,457	2,418	1,312	513	22	322	928	698	254	129	0	37	15,485
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	2,502	313	1,593	989	3,457	2,418	1,312	513	22	322	928	698	254	129	0	37	15,485
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(1)	(0)	(1)	(0)	(430)	(1)	(144)	(0)	(0)	(0)	(1)	(1)	(0)	(0)	0	(0)	(579)
Net Revenue Requirement	2,502	313	1,592	989	3,026	2,417	1,168	513	22	322	927	697	253	128	0	37	14,906

Schedule 3.1																	
Functionalized Revenue Requirement																	
Second Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	481	0	253	0	0	0	0	0	0	0	0	0	0	0	0	0	734
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	481	0	253	0	0	0	0	0	0	0	0	0	0	0	0	0	734
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	281	(24)	148	41	268	213	91	143	50	2	2	2	0	0	0	9	1,227
Total Operating Expenses	762	(24)	401	41	268	213	91	143	50	2	2	2	0	0	0	9	1,961
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761
Total Amortization	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761
Total Operating Income	3,974	5	2,178	631	3,471	2,532	1,204	2,061	417	36	21	32	7	7	0	147	16,722
Financing Expenses																	
Long-Term Debt	2,718	(88)	1,429	395	2,585	2,053	878	1,380	484	17	16	23	5	5	0	84	11,983
Short-Term Debt	113	(4)	60	16	108	86	37	58	20	1	1	1	0	0	0	4	500
Interest Charged To Constructi	(84)	3	(44)	(12)	(79)	(63)	(27)	(42)	(15)	(1)	(0)	(1)	(0)	(0)	0	(3)	(368)
Amortization of Financing Costs	1	(0)	1	0	1	1	0	1	0	0	0	0	0	0	0	0	5
Total Financing Expenses	2,749	(89)	1,445	399	2,614	2,076	888	1,396	489	17	16	24	5	5	0	85	12,119
Earnings before Income Taxes	6,723	(84)	3,623	1,030	6,085	4,608	2,092	3,457	906	53	37	56	12	11	0	232	28,841
Income Taxes	1,283	(42)	675	186	1,220	969	415	652	228	8	7	11	3	2	0	40	5,658
Net Earnings	2,778	(90)	1,460	403	2,641	2,098	897	1,411	494	17	16	24	5	5	0	86	12,246
Gross Revenue Requirement	10,783	(216)	5,757	1,620	9,946	7,676	3,404	5,519	1,629	78	60	91	20	19	0	357	46,745
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(36)	1	(19)	(5)	(34)	(27)	(11)	(18)	(6)	(0)	(0)	(0)	(0)	(0)	0	(1)	(157)
Net Revenue Requirement	10,748	(215)	5,739	1,615	9,913	7,649	3,393	5,501	1,622	78	60	91	20	19	0	356	46,588

Schedule 3.1																
Functionalized Revenue Requirement																
Total																
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																
Energy Costs	6,275	98,913	1,209	207	72	71	70	2	0	0	0	0	0	0	0	0	106,818
ECAM Adjustment	0	12,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,358
Net Energy Costs	6,275	111,270	1,209	207	72	71	70	2	0	0	0	0	0	0	0	0	119,176
Distribution	65	0	65	258	1,449	1,053	497	357	0	155	0	0	0	0	0	26	3,925
Transmission	0	0	922	0	0	0	0	0	0	0	0	0	0	0	0	0	922
Transmission and Distribution -	0	0	0	212	886	601	295	0	0	0	0	0	0	0	0	0	1,994
Transmission - OATT	0	0	172	0	0	0	0	0	0	0	0	0	0	0	0	0	172
General	2,557	144	1,324	506	1,281	1,285	525	295	72	696	929	700	562	129	0	20	11,025
Total Operating Expenses	8,897	111,414	3,693	1,182	3,687	3,009	1,387	654	73	850	929	700	562	129	0	46	137,214
Amortization																
Amortization Other	93	336	143	18	37	40	15	2	0	4	0	0	0	0	0	0	688
Amortization Plant And Equipm	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761
Total Amortization	3,304	365	1,920	608	3,240	2,359	1,129	1,919	367	38	19	30	6	6	0	138	15,450
Total Operating Income	12,201	111,780	5,612	1,791	6,927	5,369	2,516	2,574	439	889	948	730	568	135	0	184	152,663
Financing Expenses																
Long-Term Debt	2,718	(88)	1,429	395	2,585	2,053	878	1,380	484	17	16	23	5	5	0	84	11,983
Short-Term Debt	113	(4)	60	16	108	86	37	58	20	1	1	1	0	0	0	4	500
Interest Charged To Constructi	(84)	3	(44)	(12)	(79)	(63)	(27)	(42)	(15)	(1)	(0)	(1)	(0)	(0)	0	(3)	(368)
Amortization of Financing Costs	1	(0)	1	0	1	1	0	1	0	0	0	0	0	0	0	0	5
Total Financing Expenses	2,749	(89)	1,445	399	2,614	2,076	888	1,396	489	17	16	24	5	5	0	85	12,119
Earnings before Income Taxes	14,950	111,691	7,057	2,190	9,541	7,445	3,404	3,970	928	906	964	754	573	140	0	269	164,782
Income Taxes	1,283	(42)	675	186	1,220	969	415	652	228	8	7	11	3	2	0	40	5,658
Net Earnings	2,778	(90)	1,460	403	2,641	2,098	897	1,411	494	17	16	24	5	5	0	86	12,246
Gross Revenue Requirement	19,011	111,559	9,192	2,779	13,403	10,513	4,716	6,032	1,651	931	988	789	581	147	0	394	182,686
OATT Revenue	0	0	(1,830)	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,830)
Other Revenue	(36)	1	(19)	(5)	(464)	(27)	(155)	(18)	(6)	(0)	(1)	(1)	(0)	(485)	(632)	(1)	(1,852)
Net Revenue Requirement	18,975	111,560	7,343	2,774	12,939	10,485	4,561	6,014	1,645	931	987	787	581	(338)	(632)	393	179,004

Schedule 3.2 Functionalized Labour Direct Assigned ($,000)	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	1,677	0	18	0	0	0	0	0	0	0	0	0	0	0	0	0	1,695
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	1,677	0	18	0	0	0	0	0	0	0	0	0	0	0	0	0	1,695
Distribution	0	0	0	43	0	294	0	0	0	76	0	0	0	0	0	0	414
Transmission	0	0	377	0	0	0	0	0	0	0	0	0	0	0	0	0	377
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	136	0	0	0	0	0	0	0	0	0	0	0	0	0	136
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	1,677	0	531	43	0	294	0	0	0	76	0	0	0	0	0	0	2,622
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	1,677	0	531	43	0	294	0	0	0	76	0	0	0	0	0	0	2,622
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	1,677	0	531	43	0	294	0	0	0	76	0	0	0	0	0	0	2,622
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	1,677	0	531	43	0	294	0	0	0	76	0	0	0	0	0	0	2,622
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	1,677	0	531	43	0	294	0	0	0	76	0	0	0	0	0	0	2,622

Schedule 3.2																	
Functionalized Labour																	
For Allocation																	
	ECC	SCADA	T&D Plant	Distribution Lines	Distribution												Total
Operating Expenses																	
Energy Costs	796	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	806
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	796	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	806
Distribution	0	153	0	92	1,088	0	0	0	0	0	0	0	0	0	0	0	1,333
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	796	153	10	92	1,088	0	0	0	0	0	0	0	0	0	0	0	2,139
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	796	153	10	92	1,088	0	0	0	0	0	0	0	0	0	0	0	2,139
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	796	153	10	92	1,088	0	0	0	0	0	0	0	0	0	0	0	2,139
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	796	153	10	92	1,088	0	0	0	0	0	0	0	0	0	0	0	2,139
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	796	153	10	92	1,088	0	0	0	0	0	0	0	0	0	0	0	2,139

Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.2 %	4.0 %	26.0 %	17.7 %	8.8 %	17.6 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %

Schedule 3.2																	
Functionalized Labour																	
Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	66	133	201	199	69	68	67	2	0	0	0	0	0	0	0	0	806
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	66	133	201	199	69	68	67	2	0	0	0	0	0	0	0	0	806
Distribution	38	0	38	104	565	357	197	30	0	0	0	0	0	0	0	2	1,333
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	105	133	239	304	634	425	264	32	0	0	0	0	0	0	0	2	2,139
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	105	133	239	304	634	425	264	32	0	0	0	0	0	0	0	2	2,139
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	105	133	239	304	634	425	264	32	0	0	0	0	0	0	0	2	2,139
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	105	133	239	304	634	425	264	32	0	0	0	0	0	0	0	2	2,139
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	105	133	239	304	634	425	264	32	0	0	0	0	0	0	0	2	2,139

Schedule 3.2																	
Functionalized Labour																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	1,743	133	220	199	69	68	67	2	0	0	0	0	0	0	0	0	2,501
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	1,743	133	220	199	69	68	67	2	0	0	0	0	0	0	0	0	2,501
Distribution	38	0	38	148	565	651	197	30	0	76	0	0	0	0	0	2	1,747
Transmission	0	0	377	0	0	0	0	0	0	0	0	0	0	0	0	0	377
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	136	0	0	0	0	0	0	0	0	0	0	0	0	0	136
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761

MECL 2014 Cost Allocation Model

Schedule 3.3
Functionalized Vehicle

Direct Assigned ($,000)

	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	41	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	42
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	41	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	42
Distribution	0	0	0	3	0	49	0	0	0	10	0	0	0	0	0	0	61
Transmission	0	0	46	0	0	0	0	0	0	0	0	0	0	0	0	0	46
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	41	0	47	3	0	49	0	0	0	10	0	0	0	0	0	0	149
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	41	0	47	3	0	49	0	0	0	10	0	0	0	0	0	0	149
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	41	0	47	3	0	49	0	0	0	10	0	0	0	0	0	0	149
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	41	0	47	3	0	49	0	0	0	10	0	0	0	0	0	0	149
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	41	0	47	3	0	49	0	0	0	10	0	0	0	0	0	0	149

Schedule 3.3																	
Functionalized Vehicle																	
For Allocation																	
	ECC	SCADA	T&D Plant	Distribution Lines	Distribution												Total
Operating Expenses																	
Energy Costs	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19
Distribution	0	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	172
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	18	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	190
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	18	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	190
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	18	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	190
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	18	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	190
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	18	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	190
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.2 %	4.0 %	26.0 %	17.7 %	8.8 %	17.6 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %

Schedule 3.3 Functionalized Vehicle Allocation	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	2	3	5	5	2	2	2	0	0	0	0	0	0	0	0	0	19
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	2	3	5	5	2	2	2	0	0	0	0	0	0	0	0	0	19
Distribution	3	0	3	11	76	45	26	7	0	0	0	0	0	0	0	1	172
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	5	3	8	16	78	46	28	7	0	0	0	0	0	0	0	1	190
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	5	3	8	16	78	46	28	7	0	0	0	0	0	0	0	1	190
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	5	3	8	16	78	46	28	7	0	0	0	0	0	0	0	1	190
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	5	3	8	16	78	46	28	7	0	0	0	0	0	0	0	1	190
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	5	3	8	16	78	46	28	7	0	0	0	0	0	0	0	1	190

Schedule 3.3																	
Functionalized Vehicle																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	42	3	6	5	2	2	2	0	0	0	0	0	0	0	0	0	60
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	42	3	6	5	2	2	2	0	0	0	0	0	0	0	0	0	60
Distribution	3	0	3	14	76	94	26	7	0	10	0	0	0	0	0	1	233
Transmission	0	0	46	0	0	0	0	0	0	0	0	0	0	0	0	0	46
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339

Schedule 3.4																	
Functionalized Rate Base																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	69,720	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	69,720
Transmission & Distribution																	
Substations	0	0	792	2,090	0	0	0	0	0	0	0	0	0	0	0	0	2,882
Lines and Line Transformers	0	0	32,347	0	0	55,260	0	40,051	0	0	0	0	0	0	0	0	127,658
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	14,460	0	0	0	0	0	0	0	14,460
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,439	2,439
Total Transmission & Distrib	0	0	33,139	2,090	0	55,260	0	40,051	14,460	0	0	0	0	0	0	2,439	147,440
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	69,720	0	33,139	2,090	0	55,260	0	40,051	14,460	0	0	0	0	0	0	2,439	217,160
Contributions - Net	0	0	(16,215)	0	0	0	0	0	0	0	0	0	0	0	0	0	(16,215)
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECAM	0	2,669	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,669
Deferred Charges	(622)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(622)
Employee Future Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	0	(639)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(639)
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	(622)	2,029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,407
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd pre-2004 costs recove	0	992	0	0	0	0	0	0	0	0	0	0	0	0	0	0	992
Unrecoverd post-2003 costs recove	0	(9,600)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(9,600)
Regulatory Liabilities - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	3,305	0	0	0	0	0	0	0	0	0	0	0	0	0	3,305
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	3,305	0	0	0	0	0	0	0	0	0	0	0	0	0	3,305
Deferred Charge	2,239	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,239
Working Capital																	0
Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	71,337	(6,579)	20,228	2,090	0	55,260	0	40,051	14,460	0	0	0	0	0	0	2,439	199,288

Schedule 3.4																	
Functionalized Rate Base																	
For Allocation	First Allocation											Second Al	Third Allocation				
	Substations 1841 Account	ECC	SCADA	Primary & Secondary	Distribution Facilities	Distribution Lines	Distribution Network	Transportation	Labour	Head Office	Contributions Related Distribution Plant	Net Plant	Rate Base Excluding WC	O&M			Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	22,823	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22,823
Lines and Line Transformers	0	0	0	91,007	0	0	2,125	0	0	0	0	0	0	0	0	0	93,132
SCADA and Communications	0	0	4,328	0	0	0	0	0	0	0	0	0	0	0	0	0	4,328
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	22,823	0	4,328	91,007	0	0	2,125	0	0	0	0	0	0	0	0	0	120,284
Administrative & General	0	452	0	0	0	0	4,662	6,198	4,490	3,361	0	0	0	0	0	0	19,162
Gross Fixed Assets	22,823	452	4,328	91,007	0	0	6,787	6,198	4,490	3,361	0	0	0	0	0	0	139,446
Contributions - Net	0	0	0	0	0	0	0	0	0	0	(10,423)	0	0	0	0	0	(10,423)
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	(47,722)	0	0	0	0	(47,722)
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	0	0	0	0	0	0	0	0	4,475	0	0	0	0	0	0	0	4,475
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	3,681	0	0	0	0	3,681
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	9,273	0	0	0	0	9,273
Other	0	0	0	0	0	0	0	0	0	0	0	(92)	0	0	0	0	(92)
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	12,520	0	0	0	0	12,520
Total Future Income Taxes	0	0	0	0	0	0	0	0	4,475	0	0	(22,341)	0	0	0	0	(17,866)
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	431	0	0	0	0	431
Unrecoverd pre-2004 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liabilities - Other	0	0	0	0	0	0	0	0	0	0	0	(11,875)	0	0	0	0	(11,875)
Regulatory Asset - Other	0	0	0	0	0	0	0	0	1,830	0	0	0	0	0	0	0	1,830
Intangible Assets																	
Right of Ways	0	0	0	0	277	0	0	0	0	0	0	0	0	0	0	0	277
Software	0	0	0	0	0	0	0	0	752	0	0	0	0	0	0	0	752
Total Intangible Assets	0	0	0	0	277	0	0	0	752	0	0	0	0	0	0	0	1,029
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	0
Inventory	0	0	0	0	0	5,536	0	0	0	0	0	0	0	0	0	0	5,536
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	4,656	0	0	4,656
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	217	0	0	0	217
Total Working Capital	0	0	0	0	0	5,536	0	0	0	0	0	0	217	4,656	0	0	10,409
Total	22,823	452	4,328	91,007	277	5,536	6,787	6,198	11,547	3,361	(10,423)	(33,785)	217	4,656	0	0	112,981

Schedule 3.4																	
Functionalized Rate Base																	
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0.0 %	0.0 %	72.2 %	27.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	49.7 %	33.7 %	16.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Transportation	13.3 %	0.9 %	16.1 %	5.5 %	22.9 %	28.2 %	8.1 %	2.1 %	0.0 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Head Office	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %
Contributions Related Distribution I	0.0 %	0.0 %	0.0 %	0.0 %	34.8 %	23.6 %	11.6 %	23.7 %	4.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.7 %	100.0 %
Net Plant	22.1 %	0.1 %	12.0 %	3.3 %	21.2 %	17.4 %	7.2 %	11.3 %	4.2 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Rate Base Excluding WC	22.9 %	(2.0)%	12.1 %	3.3 %	21.9 %	17.4 %	7.4 %	11.7 %	4.1 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
O&M	6.0 %	82.4 %	2.4 %	0.8 %	2.5 %	2.1 %	1.0 %	0.4 %	0.0 %	0.6 %	0.7 %	0.5 %	0.4 %	0.1 %	0.0 %	0.0 %	100.0 %

Schedule 3.4																	
Functionalized Rate Base																	
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	16,470	6,353	0	0	0	0	0	0	0	0	0	0	0	0	22,823
Lines and Line Transformers	0	0	0	129	69,248	673	23,083	0	0	0	0	0	0	0	0	0	93,132
SCADA and Communications	1,082	0	1,082	1,082	361	361	361	0	0	0	0	0	0	0	0	0	4,328
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	1,082	0	17,552	7,565	69,608	1,034	23,443	0	0	0	0	0	0	0	0	0	120,284
Administrative & General	2,915	284	2,226	1,165	4,604	4,265	1,682	298	26	332	422	653	134	134	0	21	19,162
Gross Fixed Assets	3,997	284	19,777	8,729	74,212	5,299	25,125	298	26	332	422	653	134	134	0	21	139,446
Contributions - Net	0	0	0	0	(3,627)	(2,459)	(1,209)	(2,473)	(478)	0	0	0	0	0	0	(178)	(10,423)
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	1,674	125	724	326	596	676	248	30	0	72	0	0	0	0	0	2	4,475
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	1,674	125	724	326	596	676	248	30	0	72	0	0	0	0	0	2	4,475
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd pre-2004 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liabilities - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - Other	685	51	296	134	244	277	102	12	0	29	0	0	0	0	0	1	1,830
Intangible Assets																	
Right of Ways	0	0	0	0	138	94	46	0	0	0	0	0	0	0	0	0	277
Software	281	21	122	55	100	114	42	5	0	12	0	0	0	0	0	0	752
Total Intangible Assets	281	21	122	55	238	207	88	5	0	12	0	0	0	0	0	0	1,029
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	
Inventory	0	0	0	0	2,682	0	894	1,829	0	0	0	0	0	0	0	132	5,536
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Working Capital	0	0	0	0	2,682	0	894	1,829	0	0	0	0	0	0	0	132	5,536
Total	6,638	481	20,920	9,244	74,345	4,000	25,248	(298)	(451)	445	422	653	134	134	0	(21)	141,893

Schedule 3.4 Functionalized Rate Base Second Allocation	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contributions - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Taxes																	
Fixed Assets Recovery	(10,564)	(44)	(5,728)	(1,552)	(10,110)	(8,323)	(3,427)	(5,408)	(2,000)	(49)	(60)	(93)	(19)	(19)	0	(326)	(47,722)
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	815	3	442	120	780	642	264	417	154	4	5	7	1	1	0	25	3,681
Future Income Tax Asset	2,053	8	1,113	302	1,965	1,617	666	1,051	389	10	12	18	4	4	0	63	9,273
Other	(20)	(0)	(11)	(3)	(20)	(16)	(7)	(10)	(4)	(0)	(0)	(0)	(0)	(0)	0	(1)	(92)
Tax Adjustments for CAR	2,771	11	1,503	407	2,652	2,184	899	1,419	525	13	16	24	5	5	0	86	12,520
Total Future Income Taxes	(4,945)	(20)	(2,682)	(727)	(4,733)	(3,897)	(1,604)	(2,532)	(936)	(23)	(28)	(44)	(9)	(9)	0	(153)	(22,341)
Deferred Financing Costs	95	0	52	14	91	75	31	49	18	0	1	1	0	0	0	3	431
Unrecoverd pre-2004 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liabilities - Other	(2,629)	(11)	(1,425)	(386)	(2,516)	(2,071)	(853)	(1,346)	(498)	(12)	(15)	(23)	(5)	(5)	0	(81)	(11,875)
Regulatory Asset - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	
Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	(7,479)	(31)	(4,055)	(1,099)	(7,158)	(5,893)	(2,426)	(3,828)	(1,416)	(35)	(43)	(66)	(14)	(14)	0	(231)	(33,785)

Schedule 3.4																	
Functionalized Rate Base																	
Third Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contributions - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd pre-2004 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liabilities - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	
Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross operating expenses	280	3,836	113	39	118	96	45	18	1	29	32	24	19	4	0	1	4,656
Income taxes paid	50	(4)	26	7	47	38	16	25	9	0	0	0	0	0	0	2	217
Total Working Capital	330	3,832	139	47	165	134	61	43	10	30	32	24	19	5	0	3	4,873
Total	330	3,832	139	47	165	134	61	43	10	30	32	24	19	5	0	3	4,873

Schedule 3.4 Functionalized Rate Base Total	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	69,720	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	69,720
Transmission & Distribution																	
Substations	0	0	17,261	8,444	0	0	0	0	0	0	0	0	0	0	0	0	25,705
Lines and Line Transformers	0	0	32,347	129	69,248	55,933	23,083	40,051	0	0	0	0	0	0	0	0	220,790
SCADA and Communications	1,082	0	1,082	1,082	361	361	361	0	0	0	0	0	0	0	0	0	4,328
Meters	0	0	0	0	0	0	0	0	14,460	0	0	0	0	0	0	0	14,460
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,439	2,439
Total Transmission & Distrib	1,082	0	50,690	9,655	69,608	56,293	23,443	40,051	14,460	0	0	0	0	0	0	2,439	267,723
Administrative & General	2,915	284	2,226	1,165	4,604	4,265	1,682	298	26	332	422	653	134	134	0	21	19,162
Gross Fixed Assets	73,718	284	52,916	10,820	74,212	60,559	25,125	40,349	14,486	332	422	653	134	134	0	2,461	356,606
Contributions - Net	0	0	(16,215)	0	(3,627)	(2,459)	(1,209)	(2,473)	(478)	0	0	0	0	0	0	(178)	(26,638)
Future Income Taxes																	
Fixed Assets Recovery	(10,564)	(44)	(5,728)	(1,552)	(10,110)	(8,323)	(3,427)	(5,408)	(2,000)	(49)	(60)	(93)	(19)	(19)	0	(326)	(47,722)
ECAM	0	2,669	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,669
Deferred Charges	(622)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(622)
Employee Future Benefits	1,674	125	724	326	596	676	248	30	0	72	0	0	0	0	0	2	4,475
DSM	0	(639)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(639)
Future Income Tax Liability	815	3	442	120	780	642	264	417	154	4	5	7	1	1	0	25	3,681
Future Income Tax Asset	2,053	8	1,113	302	1,965	1,617	666	1,051	389	10	12	18	4	4	0	63	9,273
Other	(20)	(0)	(11)	(3)	(20)	(16)	(7)	(10)	(4)	(0)	(0)	(0)	(0)	(0)	0	(1)	(92)
Tax Adjustments for CAR	2,771	11	1,503	407	2,652	2,184	899	1,419	525	13	16	24	5	5	0	86	12,520
Total Future Income Taxes	(3,893)	2,134	(1,957)	(400)	(4,137)	(3,220)	(1,356)	(2,501)	(936)	49	(28)	(44)	(9)	(9)	0	(150)	(16,459)
Deferred Financing Costs	95	0	52	14	91	75	31	49	18	0	1	1	0	0	0	3	431
Unrecoverd pre-2004 costs recove	0	992	0	0	0	0	0	0	0	0	0	0	0	0	0	0	992
Unrecoverd post-2003 costs recov	0	(9,600)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(9,600)
Regulatory Liabilities - Other	(2,629)	(11)	(1,425)	(386)	(2,516)	(2,071)	(853)	(1,346)	(498)	(12)	(15)	(23)	(5)	(5)	0	(81)	(11,875)
Regulatory Asset - Other	685	51	296	134	244	277	102	12	0	29	0	0	0	0	0	1	1,830
Intangible Assets																	
Right of Ways	0	0	3,305	0	138	94	46	0	0	0	0	0	0	0	0	0	3,582
Software	281	21	122	55	100	114	42	5	0	12	0	0	0	0	0	0	752
Total Intangible Assets	281	21	3,427	55	238	207	88	5	0	12	0	0	0	0	0	0	4,334
Deferred Charge	2,239	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,239
Working Capital																	0
Inventory	0	0	0	0	2,682	0	894	1,829	0	0	0	0	0	0	0	132	5,536
Gross operating expenses	280	3,836	113	39	118	96	45	18	1	29	32	24	19	4	0	1	4,656
Income taxes paid	50	(4)	26	7	47	38	16	25	9	0	0	0	0	0	0	2	217
Total Working Capital	330	3,832	139	47	2,847	134	955	1,871	10	30	32	24	19	5	0	134	10,409
Total	70,826	(2,297)	37,232	10,282	67,353	53,501	22,882	35,967	12,603	440	412	611	140	125	0	2,190	312,269

Schedule 3.5																	
Functionalized Contributions Related Distribution Plant																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	69,853	0	70,327	0	0	0	0	0	0	0	0	140,179
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	13,583	0	0	0	0	0	0	0	13,583
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,062	5,062
Total Transmission & Distrib	0	0	0	0	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	158,824
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	158,824
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	158,824
For Allocation																	
	Primary &	Distribution															Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	137,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137,358
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	137,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137,358
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	137,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137,358
Intangible Assets																	
Right of Ways	0	282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	282
Total	137,358	282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137,640
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	49.7 %	33.7 %	16.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %

Schedule 3.5																	
Functionalized Contributions Related Distribution Plant																	
Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	103,019	0	34,340	0	0	0	0	0	0	0	0	0	137,358
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	103,019	0	34,340	0	0	0	0	0	0	0	0	0	137,358
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	103,019	0	34,340	0	0	0	0	0	0	0	0	0	137,358
Intangible Assets																	
Right of Ways	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Total	0	0	0	0	103,159	95	34,386	0	0	0	0	0	0	0	0	0	137,640
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	103,019	69,853	34,340	70,327	0	0	0	0	0	0	0	0	277,537
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	13,583	0	0	0	0	0	0	0	13,583
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,062	5,062
Total Transmission & Distrib	0	0	0	0	103,019	69,853	34,340	70,327	13,583	0	0	0	0	0	0	5,062	296,182
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	103,019	69,853	34,340	70,327	13,583	0	0	0	0	0	0	5,062	296,182
Intangible Assets																	
Right of Ways	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Total	0	0	0	0	103,159	69,948	34,386	70,327	13,583	0	0	0	0	0	0	5,062	296,464

Schedule 3.6																	
Functionalized Amortization																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	2,701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,701
Transmission & Distribution																	
Substations	0	0	0	92	0	0	0	0	0	0	0	0	0	0	0	0	92
Lines and Line Transformers	0	0	1,136	0	0	2,096	0	2,110	0	0	0	0	0	0	0	0	5,341
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	407	0	0	0	0	0	0	0	407
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	152	152
Total Transmission & Distrib	0	0	1,136	92	0	2,096	0	2,110	407	0	0	0	0	0	0	152	5,993
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	2,701	0	1,136	92	0	2,096	0	2,110	407	0	0	0	0	0	0	152	8,693
Contributions - Net	0	0	(377)	0	0	0	0	0	0	0	0	0	0	0	0	0	(377)
Total	2,701	0	759	92	0	2,096	0	2,110	407	0	0	0	0	0	0	152	8,316
For Allocation																	
	Substations 1841 Account	ECC	SCADA	Primary & Secondary	Distribution Facilities	Distribution Lines	Distribution Network	Transportation	Labour	Head Office	Contributions Related Distribution Plant						Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	874	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	874
Lines and Line Transformers	0	0	0	4,121	0	0	17	0	0	0	0	0	0	0	0	0	4,138
SCADA and Communications	0	0	574	0	0	0	0	0	0	0	0	0	0	0	0	0	574
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	874	0	574	4,121	0	0	17	0	0	0	0	0	0	0	0	0	5,586
Administrative & General	0	17	0	0	0	0	232	681	690	153	0	0	0	0	0	0	1,774
Gross Fixed Assets	874	17	574	4,121	0	0	249	681	690	153	0	0	0	0	0	0	7,361
Contributions - Net	0	0	0	0	0	0	0	0	0	0	(915)	0	0	0	0	0	(915)
Total	874	17	574	4,121	0	0	249	681	690	153	(915)	0	0	0	0	0	6,445

Schedule 3.6																	
Functionalized Amortization																	
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0.0 %	0.0 %	72.2 %	27.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	49.7 %	33.7 %	16.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Transportation	13.3 %	0.9 %	16.1 %	5.5 %	22.9 %	28.2 %	8.1 %	2.1 %	0.0 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Head Office	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %
Contributions Related Distribution I	0.0 %	0.0 %	0.0 %	0.0 %	34.8 %	23.6 %	11.6 %	23.7 %	4.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.7 %	100.0 %
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	631	243	0	0	0	0	0	0	0	0	0	0	0	0	874
Lines and Line Transformers	0	0	0	1	3,099	5	1,033	0	0	0	0	0	0	0	0	0	4,138
SCADA and Communications	144	0	144	144	48	48	48	0	0	0	0	0	0	0	0	0	574
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	144	0	774	388	3,146	53	1,081	0	0	0	0	0	0	0	0	0	5,586
Administrative & General	367	29	243	111	375	386	139	25	1	34	19	30	6	6	0	2	1,774
Gross Fixed Assets	511	29	1,018	499	3,521	439	1,219	25	1	34	19	30	6	6	0	2	7,361
Contributions - Net	0	0	0	0	(318)	(216)	(106)	(217)	(42)	0	0	0	0	0	0	(16)	(915)
Total	511	29	1,018	499	3,203	223	1,113	(192)	(41)	34	19	30	6	6	0	(14)	6,445

Schedule 3.6																	
Functionalized Amortization																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	2,701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,701
Transmission & Distribution																	
Substations	0	0	631	335	0	0	0	0	0	0	0	0	0	0	0	0	966
Lines and Line Transformers	0	0	1,136	1	3,099	2,101	1,033	2,110	0	0	0	0	0	0	0	0	9,479
SCADA and Communications	144	0	144	144	48	48	48	0	0	0	0	0	0	0	0	0	574
Meters	0	0	0	0	0	0	0	0	407	0	0	0	0	0	0	0	407
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	152	152
Total Transmission & Distrib	144	0	1,911	480	3,146	2,149	1,081	2,110	407	0	0	0	0	0	0	152	11,579
Administrative & General	367	29	243	111	375	386	139	25	1	34	19	30	6	6	0	2	1,774
Gross Fixed Assets	3,212	29	2,154	590	3,521	2,535	1,219	2,135	409	34	19	30	6	6	0	154	16,054
Contributions - Net	0	0	(377)	0	(318)	(216)	(106)	(217)	(42)	0	0	0	0	0	0	(16)	(1,293)
Total	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761

Schedule 4.0																	
Functionalized Gross Plant																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	110,331	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110,331
Transmission & Distribution																	
Substations	0	0	808	2,878	0	0	0	0	0	0	0	0	0	0	0	0	3,685
Lines and Line Transformers	0	0	49,561	0	0	69,853	0	70,327	0	0	0	0	0	0	0	0	189,740
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	13,583	0	0	0	0	0	0	0	13,583
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,062	5,062
Total Transmission & Distrib	0	0	50,369	2,878	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	212,070
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	110,331	0	50,369	2,878	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	322,401
Intangible Assets																	
Right of Ways	0	0	4,470	0	0	0	0	0	0	0	0	0	0	0	0	0	4,470
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	4,470	0	0	0	0	0	0	0	0	0	0	0	0	0	4,470
Total	110,331	0	54,839	2,878	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	326,871

For Allocation	First Allocation				Second Al	Third Allocation											
	Substations 1841 Account	ECC	SCADA	Primary & Secondar	Distribution Facilities	Distribution Network	Transportation	Labour	Head Office								Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	38,006	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	38,006
Lines and Line Transformers	0	0	0	137,358	0	2,134	0	0	0	0	0	0	0	0	0	0	139,492
SCADA and Communications	0	0	9,574	0	0	0	0	0	0	0	0	0	0	0	0	0	9,574
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	38,006	0	9,574	137,358	0	2,134	0	0	0	0	0	0	0	0	0	0	187,072
Administrative & General	0	697	0	0	0	7,255	9,086	5,664	5,114	0	0	0	0	0	0	0	27,815
Gross Fixed Assets	38,006	697	9,574	137,358	0	9,389	9,086	5,664	5,114	0	0	0	0	0	0	0	214,887
Intangible Assets																	
Right of Ways	0	0	0	0	282	0	0	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	1,794	0	0	0	0	0	0	0	0	1,794
Total Intangible Assets	0	0	0	0	282	0	0	1,794	0	0	0	0	0	0	0	0	2,076
Total	38,006	697	9,574	137,358	282	9,389	9,086	7,458	5,114	0	0	0	0	0	0	0	216,964

Schedule 4.0																	
Functionalized Gross Plant																	
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0.0 %	0.0 %	72.2 %	27.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	49.7 %	33.7 %	16.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Transportation	13.3 %	0.9 %	16.1 %	5.5 %	22.9 %	28.2 %	8.1 %	2.1 %	0.0 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Head Office	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	27,426	10,580	0	0	0	0	0	0	0	0	0	0	0	0	38,006
Lines and Line Transformers	0	0	0	0	103,019	0	34,340	0	0	0	0	0	0	0	0	0	137,358
SCADA and Communications	2,394	0	2,394	2,394	798	798	798	0	0	0	0	0	0	0	0	0	9,574
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	2,394	0	29,819	12,973	103,816	798	35,137	0	0	0	0	0	0	0	0	0	184,938
Administrative & General	58	116	174	174	58	58	58	0	0	0	0	0	0	0	0	0	697
Gross Fixed Assets	2,452	116	29,994	13,147	103,874	856	35,195	0	0	0	0	0	0	0	0	0	185,635
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	2,452	116	29,994	13,147	103,874	856	35,195	0	0	0	0	0	0	0	0	0	185,635

Schedule 4.0																	
Functionalized Gross Plant																	
Second Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Total	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Third Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	130	996	676	332	0	0	0	0	0	0	0	0	0	2,134
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	130	996	676	332	0	0	0	0	0	0	0	0	0	2,134
Administrative & General	3,896	282	2,970	1,506	6,789	6,210	2,434	438	40	476	643	994	205	205	0	32	27,119
Gross Fixed Assets	3,896	282	2,970	1,636	7,785	6,886	2,766	438	40	476	643	994	205	205	0	32	29,253
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	671	50	290	131	239	271	100	12	0	29	0	0	0	0	0	1	1,794
Total Intangible Assets	671	50	290	131	239	271	100	12	0	29	0	0	0	0	0	1	1,794
Total	4,567	332	3,261	1,767	8,024	7,157	2,866	451	40	505	643	994	205	205	0	32	31,047

Schedule 4.0																	
Functionalized Gross Plant																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	110,331	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110,331
Transmission & Distribution																	
Substations	0	0	28,234	13,457	0	0	0	0	0	0	0	0	0	0	0	0	41,691
Lines and Line Transformers	0	0	49,561	130	104,015	70,528	34,672	70,327	0	0	0	0	0	0	0	0	329,232
SCADA and Communications	2,394	0	2,394	2,394	798	798	798	0	0	0	0	0	0	0	0	0	9,574
Meters	0	0	0	0	0	0	0	0	13,583	0	0	0	0	0	0	0	13,583
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,062	5,062
Total Transmission & Distrib	2,394	0	80,188	15,981	104,813	71,326	35,469	70,327	13,583	0	0	0	0	0	0	5,062	399,142
Administrative & General	3,954	398	3,144	1,680	6,847	6,268	2,492	438	40	476	643	994	205	205	0	32	27,815
Gross Fixed Assets	116,678	398	83,332	17,661	111,660	77,595	37,962	70,765	13,623	476	643	994	205	205	0	5,094	537,288
Intangible Assets																	
Right of Ways	0	0	4,470	0	140	95	47	0	0	0	0	0	0	0	0	0	4,752
Software	671	50	290	131	239	271	100	12	0	29	0	0	0	0	0	1	1,794
Total Intangible Assets	671	50	4,761	131	379	366	146	12	0	29	0	0	0	0	0	1	6,547
Total	117,350	448	88,093	17,792	112,039	77,961	38,108	70,777	13,623	505	643	994	205	205	0	5,094	543,835

Schedule 4.1	
Revenue Requirement Summary ($,0000)	
Operating Expenses	
Energy Costs	106,818
ECAM Adjustment	12,358
Net Energy Costs	119,176
Distribution	3,925
Transmission	922
Transmission and Distribution -	1,994
Transmission - OATT	172
General	11,025
Total Operating Expenses	137,214
Amortization	
Amortization Other	688
Amortization Plant And Equipme	14,761
Total Amortization	15,450
Total Operating Income	152,663
Financing Expenses	
Long-Term Debt	11,983
Short-Term Debt	500
Interest Charged To Constructi	(368)
Amortization of Financing Costs	5
Total Financing Expenses	12,119
Earnings before Income Taxes	164,782
Income Taxes	5,658
Net Earnings	12,246
Gross Revenue Requirement	182,686
OATT Revenue	(1,830)
Other Revenue	(1,852)
Net Revenue Requirement	179,004

Schedule 4.2				
Rate Base ($,000)				
	Open	Close	Mid Year	Basis for Functionalization
Fixed Assets				
Production	69,831	69,610	69,720	Detailed Analysis
Transmission & Distribution				
Substations	25,028	26,382	25,705	Detailed Analysis
Lines and Line Transformers	216,131	225,450	220,790	Detailed Analysis
SCADA and Communications	4,471	4,185	4,328	Detailed Analysis
Meters	14,107	14,813	14,460	Detailed Analysis
Street & Private Area Lights	2,332	2,547	2,439	Detailed Analysis
Total Transmission & Distrib	262,069	273,377	267,723	
Administrative & General	18,851	19,473	19,162	Detailed Analysis
Net Fixed Assets	350,751	362,461	356,606	
Contributions - Net	(27,022)	(26,255)	(26,638)	Detailed Analysis
Future Income Taxes				
Fixed Assets Recovery	(45,858)	(49,586)	(47,722)	Net Plant
ECAM	3,768	1,569	2,669	Purchased Power
Deferred Charges	(637)	(608)	(622)	Generation
Employee Future Benefits	3,784	5,166	4,475	Labour
DSM	(108)	(1,170)	(639)	Purchased Power
Future Income Tax Liability	3,188	4,174	3,681	Net Plant
Future Income Tax Asset	8,210	10,336	9,273	Net Plant
Other	(487)	302	(92)	Net Plant
Tax Adjustments for CAR	12,520	12,520	12,520	Net Plant
Total Future Income Taxes	(15,620)	(17,298)	(16,459)	Net Plant
Deferred Financing Costs	433	428	431	Net Plant
Unrecoverd pre-2004 costs recove	1,984	0	992	Purchased Power
Unrecoverd post-2003 costs recove	(14,138)	(5,062)	(9,600)	Purchased Power
Regulatory Liabilities - Other	(10,285)	(13,465)	(11,875)	Net Plant
Regulatory Asset - Other	0	3,660	1,830	Labour
Intangible Assets				
Right of Ways	3,670	3,495	3,582	Detailed Analysis
Software	727	776	752	Detailed Analysis
Total Intangible Assets	4,397	4,271	4,334	
Deferred Charge	2,404	2,075	2,239	Generation
Working Capital				
Inventory	5,363	5,710	5,536	Distribution Lines
Gross operating expenses	4,604	4,709	4,656	O&M
Income taxes paid	306	128	217	Rate Base Excluding WC
Total Working Capital	10,273	10,546	10,409	
Rate Base	303,176	321,361	312,269	

Schedule 5.0
Functional Allocator Summary

Percent (%)

Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Exogenous Allocators																	
Substations 1841 Account	0.0 %	0.0 %	72.2 %	27.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Allocators Based on Fixed Assets																	
Environmental	50.0 %	0.0 %	0.0 %	2.0 %	0.0 %	48.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Transformers	0.0 %	0.0 %	1.1 %	3.9 %	0.0 %	95.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	49.7 %	33.7 %	16.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Right of Way Amortization	0.0 %	0.0 %	91.9 %	0.0 %	4.0 %	2.7 %	1.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Engineering	0.6 %	0.0 %	21.1 %	4.0 %	25.8 %	17.6 %	8.8 %	17.5 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Procurement	0.0 %	0.0 %	21.0 %	3.4 %	26.3 %	17.8 %	8.8 %	17.9 %	3.5 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.2 %	4.0 %	26.0 %	17.7 %	8.8 %	17.6 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Total Plant	21.6 %	0.1 %	16.2 %	3.3 %	20.6 %	14.3 %	7.0 %	13.0 %	2.5 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.9 %	100.0 %
Contributions Related Distributi	0.0 %	0.0 %	0.0 %	0.0 %	34.8 %	23.6 %	11.6 %	23.7 %	4.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.7 %	100.0 %
Amortization	21.8 %	0.2 %	12.0 %	4.0 %	21.7 %	15.7 %	7.5 %	13.0 %	2.5 %	0.2 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.9 %	100.0 %
Net Plant	22.1 %	0.1 %	12.0 %	3.3 %	21.2 %	17.4 %	7.2 %	11.3 %	4.2 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Rate Base Excluding WC	22.9 %	(2.0)%	12.1 %	3.3 %	21.9 %	17.4 %	7.4 %	11.7 %	4.1 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
G&T Rate Base	65.5 %	0.0 %	34.5 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Rate Base	22.7 %	(0.7)%	11.9 %	3.3 %	21.6 %	17.1 %	7.3 %	11.5 %	4.0 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Allocators Based on O&M																	
Transportation	13.3 %	0.9 %	16.1 %	5.5 %	22.9 %	28.2 %	8.1 %	2.1 %	0.0 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
O&M	6.0 %	82.4 %	2.4 %	0.8 %	2.5 %	2.1 %	1.0 %	0.4 %	0.0 %	0.6 %	0.7 %	0.5 %	0.4 %	0.1 %	0.0 %	0.0 %	100.0 %
Blended Allocators																	
Finance Labour	10.7 %	0.8 %	9.1 %	2.8 %	9.4 %	8.1 %	3.5 %	4.0 %	0.7 %	0.5 %	28.6 %	21.4 %	0.0 %	0.0 %	0.0 %	0.3 %	100.0 %
Finance Admin	5.3 %	0.4 %	4.6 %	1.4 %	4.7 %	4.1 %	1.7 %	2.0 %	0.4 %	0.2 %	64.3 %	10.7 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Customer Service	0.0 %	0.0 %	2.8 %	0.0 %	1.8 %	1.8 %	1.8 %	0.0 %	0.0 %	27.8 %	11.0 %	22.0 %	25.5 %	5.5 %	0.0 %	0.0 %	100.0 %
Head Office	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %

Schedule 5.1																
Functional Allocator Worksheet																
Exogenous Allocators																
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0	0	72	28	0	0	0	0	0	0	0	0	0	0	0	0	100
Primary & Secondary	0	0	0	0	75	0	25	0	0	0	0	0	0	0	0	0	100
Call Center	0	0	5	0	3	3	3	0	0	5	20	40	10	10	0	0	100
ECC	8	17	25	25	8	8	8	0	0	0	0	0	0	0	0	0	100
SCADA	25	0	25	25	8	8	8	0	0	0	0	0	0	0	0	0	100
Allocators Based on Fixed Assets ($,000)																
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Environmental																	0
Wires	0	0	0	2,868	0	69,853	0	0	0	0	0	0	0	0	0	0	72,720
Generation	72,720																72,720
Total	72,720	0	0	2,868	0	69,853	0	0	0	0	0	0	0	0	0	0	145,441
T&D Transformers																	
Substations			808	2,878													3,685
Lines and Line Transformers						69,853											69,853
Total	0	0	808	2,878	0	69,853	0	0	0	0	0	0	0	0	0	0	73,538
Distribution Facilities																	
Substations					0	0	0										0
Lines and Line Transformers					103,019	69,853	34,340										207,211
Total	0	0	0	0	103,019	69,853	34,340	0	0	0	0	0	0	0	0	0	207,211
Right of Way Amortization																	
Transmission Component			100.0 %														103
Distribution Component					49.7 %	33.7 %	16.6 %										9
Total	0	0	103	0	4	3	1	0	0	0	0	0	0	0	0	0	112
Engineering																	
Total Transmission & Distribut	2,394	0	80,188	15,851	103,816	70,651	35,137	70,327	13,583	0	0	0	0	0	0	5,062	397,008
Administrative & General	58	116	174	174	58	58	58	0	0	0	0	0	0	0	0	0	697
Right of Ways	0	0	4,470	0	140	95	47	0	0	0	0	0	0	0	0	0	4,752
Total	2,452	116	84,833	16,025	104,015	70,804	35,242	70,327	13,583	0	0	0	0	0	0	5,062	402,457
Procurement																	
Substations	0	0	28,234	13,457	0	0	0	0	0	0	0	0	0	0	0	0	41,691
Lines and Line Transformers	0	0	49,561	0	103,019	69,853	34,340	70,327	0	0	0	0	0	0	0	0	327,098
Meters	0	0	0	0	0	0	0	0	13,583	0	0	0	0	0	0	0	13,583
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,062	5,062
Right of Ways	0	0	4,470	0	140	95	47	0	0	0	0	0	0	0	0	0	4,752
Total	0	0	82,265	13,457	103,159	69,948	34,386	70,327	13,583	0	0	0	0	0	0	5,062	392,186
Distribution Lines					103,159		34,386	70,327								5,062	212,934
Distribution Network				13,457	103,159	69,948	34,386										220,950
T&D Plant			84,833	16,025	104,015	70,804	35,242	70,327	13,583	0	0	0	0	0	0	5,062	399,890
Total Plant	117,350	448	88,093	17,792	112,039	77,961	38,108	70,777	13,623	505	643	994	205	205	0	5,094	543,835
Contributions Related Distribution	0	0	0	0	103,159	69,948	34,386	70,327	13,583	0	0	0	0	0	0	5,062	296,464
Amortization	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761
Net Plant																	
Gross Fixed Assets	73,718	284	52,916	10,820	74,212	60,559	25,125	40,349	14,486	332	422	653	134	134	0	2,461	356,606
Contributions - Net	0	0	(16,215)	0	(3,627)	(2,459)	(1,209)	(2,473)	(478)	0	0	0	0	0	0	(178)	(26,638)
Total Intangible Assets	281	21	3,427	55	238	207	88	5	0	12	0	0	0	0	0	0	4,334
Total	73,999	305	40,127	10,875	70,823	58,307	24,004	37,882	14,009	344	422	653	134	134	0	2,283	334,302
Rate Base Excluding WC	70,496	(6,129)	37,093	10,236	67,188	53,367	22,822	35,924	12,593	410	380	587	121	121	0	2,187	307,396
G&T Rate Base	70,826		37,232														108,058
Rate Base	70,826	(2,297)	37,232	10,282	67,353	53,501	22,882	35,967	12,603	440	412	611	140	125	0	2,190	312,269
Allocators Based on O&M ($,000)																
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Transportation	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339
Labour	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761
O&M	8,135	111,439	3,292	1,142	3,419	2,796	1,296	511	22	849	928	698	561	129	0	37	135,253

Schedule 5.2																	
Functional Allocator Worksheet, Blended Allocators																	
Finance Labour																	
FTEs by Function																	
Billing	2.0	Billing															
Customer Payments	1.0	Remittance & Collection															
Collection	0.5	Remittance & Collection															
Purchasing	0.5	Procurement															
Payroll	1.0	Labour															
Accounts Receivable (Non-Elect	1.0	Labour															
Accounts Payable	1.0	Procurement															
Total	7.0																
Weighting																	
Allocator	Weight																
Billing	29 %																
Remittance & Collection	21 %																
Procurement	21 %																
Labour	29 %																
Total	100 %																
Allocator Components																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Billing											100.0 %						100.0 %
Remittance & Collection												100.0 %					100.0 %
Procurement	0.0 %	0.0 %	21.0 %	3.4 %	26.3 %	17.8 %	8.8 %	17.9 %	3.5 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Average	10.7 %	0.8 %	9.1 %	2.8 %	9.4 %	8.1 %	3.5 %	4.0 %	0.7 %	0.5 %	28.6 %	21.4 %	0.0 %	0.0 %	0.0 %	0.3 %	100.0 %
Finance Admin																	
Weighting																	
Finance Labour	50 %																
Billing	50 %																
Total	100 %																
Allocator Components																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Finance Labour	10.7 %	0.8 %	9.1 %	2.8 %	9.4 %	8.1 %	3.5 %	4.0 %	0.7 %	0.5 %	28.6 %	21.4 %	0.0 %	0.0 %	0.0 %	0.3 %	100.0 %
Billing											100.0 %						100.0 %
Average	5.3 %	0.4 %	4.6 %	1.4 %	4.7 %	4.1 %	1.7 %	2.0 %	0.4 %	0.2 %	64.3 %	10.7 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Customer Service																	
Weighting																	
Call Centre	55 %																
Uncollectibles & Damage Claims	20 %																
Meter Reading	25 %																
Total	100 %																

Schedule 5.2

Functional Allocator Worksheet, Blended Allocators

Allocator Components

Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
Uncollectibles & Damage Claims													100.0 %				100.0 %
Meter Reading										100.0 %							100.0 %
Average	0.0 %	0.0 %	2.8 %	0.0 %	1.8 %	1.8 %	1.8 %	0.0 %	0.0 %	27.8 %	11.0 %	22.0 %	25.5 %	5.5 %	0.0 %	0.0 %	100.0 %

Head Office

Allocation of Head Office Floor Space

Function	Floor	Occupancy	Allocator
Customer Service	1	100 %	Call Center
Customer Service	2	100 %	Call Center
Engineering	3	75 %	Engineering
Information Technology	3	25 %	Labour
Finance	4	80 %	Finance Labour
Procurement	4	20 %	Procurement
Executive	5	100 %	Labour

Weighting

Allocator	Weight
Call Center	40 %
Finance Labour	16 %
Engineering	15 %
Procurement	4 %
Labour	25 %
Total	100 %

Allocator Components

Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
Finance Labour	10.7 %	0.8 %	9.1 %	2.8 %	9.4 %	8.1 %	3.5 %	4.0 %	0.7 %	0.5 %	28.6 %	21.4 %	0.0 %	0.0 %	0.0 %	0.3 %	100.0 %
Engineering	0.6 %	0.0 %	21.1 %	4.0 %	25.8 %	17.6 %	8.8 %	17.5 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Procurement	0.0 %	0.0 %	21.0 %	3.4 %	26.3 %	17.8 %	8.8 %	17.9 %	3.5 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Average	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %

Schedule 6.0								
Revenue Requirement 2014								
Account	Description	2014 Trial Balance	Power Supply Demand Related	Labour Related	Vehicle Related	O&M Reporting	Functionalization Method	Power Supply Demand Related (%)

[redacted]

Schedule 6.0								
Revenue Requirement 2014								

[redacted]

Schedule 6.0	
Revenue Requirement 2014	

[redacted]

Schedule 6.1														
Plant In Service 2014														
		Fixed Assets			Accumulated Amortization			WIP			Net	Annual		
Account	Name	pen	lose	Year	pen	lose	Year	pen	lose	Year	Fixed Assets	Amortization	Presentation Header	Basis for Functionalization
1101	Prod Power Plant Land	2,261,810	2,261,810	2,261,810	0	0	0	0	0	0	2,261,810	0	Production	Generation
1102	Prod Power Plant Build & Structure	7,673,269	7,918,834	7,796,051	3,509,033	3,619,017	3,564,025	(0)	0	(0)	4,232,026	194,901	Production	Generation
1103	Prod Pumphouse Elect Equip	1,630,613	1,630,613	1,630,613	998,295	1,039,060	1,018,677	0	0	0	611,935	40,765	Production	Generation
1104	Prod Pumphouse Mech Equip	32,949	32,949	32,949	20,172	20,996	20,584	0	0	0	12,365	824	Production	Generation
1105	Prod Boiler Plant Equip	24,532,276	24,674,199	24,603,237	13,698,121	14,235,324	13,966,723	0	0	0	10,636,515	615,081	Production	Generation
1107	Prod Turbine & Aux Equip	22,001,131	22,091,772	22,046,451	11,301,421	11,783,906	11,542,664	(0)	0	(0)	10,503,788	551,161	Production	Generation
1109	Gas Turbine & Aux Equip	34,676,317	34,716,216	34,696,267	4,409,364	5,237,119	4,823,241	0	0	0	29,873,025	867,407	Production	Generation
1113	Prod Elect Equip Plant & Yard	2,283,113	2,283,113	2,283,113	1,647,824	1,704,902	1,676,363	0	0	0	606,750	57,078	Production	Generation
1115	Prod Misc Power Plant Equip	1,506,403	1,506,403	1,506,403	905,300	942,960	924,130	0	0	0	582,273	37,660	Production	Generation
1135	Prod Shop Equip	6,483	6,483	6,483	3,964	4,126	4,045	0	0	0	2,438	162	Production	Generation
1139	Prod River Pumphouse Build	1,026,497	1,026,497	1,026,497	364,822	390,484	377,653	0	0	0	648,844	25,662	Production	Generation
1201	Prod Borden Power Plant Land	43,567	43,567	43,567	0	0	0	0	0	0	43,567	0	Production	Generation
1202	Prod Borden Build & Structures	481,306	481,306	481,306	155,789	167,822	161,806	0	0	0	319,500	12,033	Production	Generation
1209	Prod Borden Gas Turbine & Aux Eq	10,821,169	11,966,968	11,394,068	2,474,170	2,214,800	2,344,485	(0)	0	(0)	9,049,583	284,852	Production	Generation
1215	Prod Borden Misc Equip	320,116	320,116	320,116	82,393	90,396	86,394	0	0	0	233,722	8,003	Production	Generation
1301	ECC Land	20,470	20,470	20,470	0	0	0	0	0	0	20,470	0	Administrative & General	ECC
1315	Prod ECC Misc Power Plant Equip	201,817	201,817	201,817	97,021	102,067	99,544	0	0	0	102,274	5,045	Production	Generation
1355	ECC UG Cables	0	0	0	0	0	0	0	0	0	0	0	Production	Generation
1379	ECC Build	676,209	676,209	676,209	236,136	253,041	244,589	0	0	0	431,620	16,905	Administrative & General	ECC
1740	Dist Substation Land	4,506	4,506	4,506	0	0	0	0	0	0	4,506	0	Substations	Substations
1741	Dist Substation Equip Build & Stru	2,815,526	2,919,644	2,867,585	741,196	832,959	787,078	(0)	0	(0)	2,080,507	91,763	Substations	Substations
1744	Dist Land	5,467	5,467	5,467	0	0	0	0	0	0	5,467	0	Substations	Substations
1748	Dist OH Conductors	65,119,477	69,263,558	67,191,518	19,115,890	20,830,963	19,973,427	(0)	3,478	1,739	47,216,352	2,015,746	Lines and Line Transformers	Primary & Secondary
1749	Dist Poles & Fixtures	57,501,574	59,641,439	58,571,506	22,533,443	23,928,532	23,230,987	(0)	0	(0)	35,340,519	1,757,145	Lines and Line Transformers	Primary & Secondary
1750	Dist Line Control Devices	8,540,526	8,839,199	8,689,862	2,144,193	2,015,879	2,080,036	3,156	1,952	2,554	6,607,272	260,696	Lines and Line Transformers	Primary & Secondary
1751	Dist Tranformers	58,638,965	61,376,167	60,007,566	12,758,027	13,197,361	12,977,694	(15)	0	(7)	47,029,880	1,800,227	Lines and Line Transformers	Transformers
1752	Dist Transformer Installations	9,452,237	10,237,963	9,845,100	1,538,824	1,691,625	1,615,225	(0)	0	(0)	8,229,875	295,353	Lines and Line Transformers	Transformers
1753	Dist Service Lines	66,898,375	69,751,188	68,324,782	28,451,345	30,406,155	29,428,750	0	876	438	38,895,594	2,049,743	Lines and Line Transformers	Service Lines
1754	Dist Street & Yard Lights	4,273,604	4,542,820	4,408,212	2,109,846	2,143,939	2,126,893	0	0	0	2,281,320	132,246	Street & Private Area Lights	Lighting
1755	Dist UG Conductors	2,874,264	2,936,144	2,905,204	1,020,590	1,104,321	1,062,456	0	0	0	1,842,748	87,156	Lines and Line Transformers	Primary & Secondary
1756	Dist UG Service Lines	1,994,639	2,009,154	2,001,897	817,026	873,897	845,462	0	1,261	631	1,155,804	60,057	Lines and Line Transformers	Service Lines
1757	Dist UG System Street Lights	653,789	653,789	653,789	485,835	505,449	495,642	0	0	0	158,147	19,614	Street & Private Area Lights	Lighting
1758	Dist Meters	12,956,979	13,399,311	13,178,145	324,982	183,350	254,166	(0)	0	(0)	12,923,979	395,344	Meters	Meter Assets
1759	Dist Meter Installations	384,244	424,951	404,598	(1,090,401)	(1,172,447)	(1,131,424)	0	0	0	1,536,022	12,138	Meters	Meter Assets
1760	Dist Communications System	7,846,450	8,203,900	8,025,175	4,106,516	4,588,027	4,347,272	(0)	69,460	34,730	3,643,174	481,511	SCADA and Communications	SCADA
1761	Dist Eng Test & Survey Equip	659,734	671,319	665,527	237,437	258,734	248,085	0	0	0	417,441	21,297	Administrative & General	Distribution Network
1762	Dist Tools & Stores Equip	853,852	909,867	881,860	312,902	341,121	327,012	533	0	267	554,581	28,220	Administrative & General	Distribution Network
1763	Supervisory Scada System	1,549,237	1,549,237	1,549,237	817,685	910,640	864,163	0	0	0	685,075	92,954	SCADA and Communications	SCADA
1777	Dist General Property Land	329,731	329,731	329,731	0	0	0	0	0	0	329,731	0	Administrative & General	Head Office
1778	Dist General Prop Build Office	4,668,598	4,900,561	4,784,580	1,684,906	1,822,696	1,753,801	0	0	0	3,030,779	153,107	Administrative & General	Head Office
1779	Dist General Property Build Distric	5,565,393	5,849,767	5,707,580	1,929,293	2,106,579	2,017,936	0	0	0	3,689,644	182,643	Administrative & General	Distribution Network
1780	Office Equip	857,328	862,362	859,845	562,092	589,607	575,849	0	0	0	283,995	27,515	Administrative & General	Labour
1781	Transportation Equip	8,476,117	9,695,001	9,085,559	2,518,932	3,172,675	2,845,803	84,000	0	42,000	6,197,756	681,417	Administrative & General	Transportation
1784	Computer Hardware	1,417,566	1,597,955	1,507,761	(109,717)	88,144	(10,786)	0	0	0	1,518,547	208,071	Administrative & General	Labour
1785	Computer Software	3,145,225	3,447,412	3,296,319	363,046	817,938	590,492	0	36,678	18,339	2,687,488	454,892	Administrative & General	Labour
1786	Marketing & Transition	0	0	0	0	0	0	0	0	0	0	0	Administrative & General	Labour
1840	Trans Substation Land	364,362	397,257	380,810	0	0	0	0	32,379	16,190	364,620	0	Substations	Transmission
1841	Trans Substation Equip, Build & St	36,615,548	39,395,488	38,005,518	14,002,220	14,859,765	14,430,992	460,987	1,042,162	751,575	22,822,951	874,127	Substations	Substations 1841 Account
1844	Trans Land	427,117	427,117	427,117	0	0	0	0	0	0	427,117	0	Substations	Transmission
1846	Road & Trails	73,263	73,263	73,263	7,566	9,251	8,409	0	0	0	64,854	1,685	Lines and Line Transformers	Transmission
1847	Trans Towers	878,834	878,834	878,834	652,299	672,513	662,406	0	0	0	216,428	20,213	Lines and Line Transformers	Transmission
1848	Trans OH Conductors	29,493,862	31,744,072	30,618,967	9,541,759	10,191,202	9,866,480	0	632,350	316,175	20,436,311	704,236	Lines and Line Transformers	Transmission
1849	Trans Poles & Fixtures	15,410,819	17,037,165	16,223,992	5,569,711	5,543,658	5,556,685	50,870	656,091	353,481	10,313,827	373,152	Lines and Line Transformers	Transmission
1850	Trans Line Control Devices	1,503,853	1,696,474	1,600,164	427,946	446,774	437,360	0	25,900	12,950	1,149,854	36,804	Lines and Line Transformers	Transmission
1855	Trans UG Cables	0	0	0	0	0	0	0	(0)	(0)	0	0	Lines and Line Transformers	Transmission
1877	Trans General Property Land	165,586	165,586	165,586	0	0	0	0	0	0	165,586	0	Lines and Line Transformers	Transmission
Subtotal PPE		522,612,164	547,697,014	535,154,589	173,479,218	184,767,328	179,123,273	599,532	2,502,587	1,551,060	354,480,257	16,036,610		
3200	Material & Supply Line Hardwar	2,217,587	2,042,567	2,130,077	0	0	0	0	0	0	2,130,077	0	Lines and Line Transformers	Distribution Network
3205	PST Material & Supply Line Har	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
3210	COGP Line Hardware	(0)	4,451	2,226	0	0	0	0	0	0	2,226	0	Lines and Line Transformers	Distribution Network
3212	COGP LH Price Variance	0	13,190	6,595	0	0	0	0	0	0	6,595	0	Lines and Line Transformers	Distribution Network
3215	COGP Other	(533)	0	(267)	0	0	0	0	0	0	(267)	0	Lines and Line Transformers	Distribution Network
3217	COGP Other Price Variance	0	(9,642)	(4,821)	0	0	0	0	0	0	(4,821)	0	Lines and Line Transformers	Distribution Network
3220	Material Quantity Variance	0	(3)	(1)	0	0	0	0	0	0	(1)	0	Lines and Line Transformers	Distribution Network
3305	HRLY Clearing	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
Subtotal Inventory		2,217,054	2,050,563	2,133,808	0	0	0	0	0	0	2,133,808	0		
WIP Adjustment		0	0	0	0	17,147	8,573	(518)	1	(259)	(8,315)	17,147	Lines and Line Transformers	Distribution Network
Total Fixed Assets		524,829,218	549,747,577	537,288,398	173,479,218	184,784,475	179,131,847	599,014	2,502,588	1,550,801	356,605,750	16,053,757		

Schedule 6.2							
Contributions & Intangible Assets							
Contributions		Gross					
Account	Name	Open	Close	Change	id Year		
4500	Contributions - New Services	29,354,789	29,884,859	530,070	29,619,824		
4503	Contributions - Extensions	369,349	369,349	0	369,349		
4510	Refundable Contributions	523,749	518,916	(4,834)	521,332		
4505	Contributions - Other	16,403,842	16,403,842	0	16,403,842		
Total Gross		46,651,729	47,176,965	525,236	46,914,347		
		Accumulated Amortization					
		Open	Close	Change	id Year	Basis for Functionalization	
4501	Amortization Contributions	19,629,685	20,545,000	915,315	20,087,343	Contributions Related Distribution Plant	
4501	Amortization Contributions	0	377,288	377,288	188,644	Transmission	
Total Accumulated Amortization		19,629,685	20,922,289	1,292,604	20,275,987		
		Total Net					
		Open	Close	Change	id Year	Basis for Functionalization	
	Distribution	10,618,202	10,228,123	(390,079)	10,423,162	Contributions Related Distribution Plant	
	Transmission	16,403,842	16,026,554	(377,288)	16,215,198	Transmission	
	Total Net	27,022,044	26,254,677	(767,367)	26,638,360		
Intangible		Gross					
Account	Name	Open	Close	Change	id Year	Presentation Header	Basis for Functionalization
3580	ROW Distribution	282,000	282,000	0	282,000	Right of Ways	Distribution Facilities
3580	ROW Transmission	4,502,049	4,438,646	(63,403)	4,470,348	Right of Ways	Transmission
3585	CIS and EPS	1,646,388	1,942,601	296,214	1,794,495	Software	Labour
Total Gross		6,430,437	6,663,247	232,811	6,546,842		
		Accumulated Amortization					
Account	Name	Open	Close	Change	id Year	Presentation Header	Basis for Functionalization
3580	ROW Distribution	0	9,024	9,024	4,512	Right of Ways	Distribution Facilities
3580	ROW Transmission	1,114,042	1,216,860	102,818	1,165,451	Right of Ways	Transmission
3585	CIS and EPS	918,940	1,166,580	247,640	1,042,760		
Total Accumulated Amortization		2,032,981	2,392,463	359,482	2,212,722		
		Total Net					
Account	Name	Open	Close	Change	id Year	Presentation Header	Basis for Functionalization
3580	ROW Distribution	282,000	272,976	(9,024)	277,488	Right of Ways	Distribution Facilities
3580	ROW Transmission	3,388,008	3,221,787	(166,221)	3,304,897	Right of Ways	Transmission
3585	CIS and EPS	727,448	776,022	48,573	751,735	Software	Labour
Total Net		4,397,456	4,270,784	(126,672)	4,334,120		