Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

- and -

IN THE MATTER OF an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff

Consensus Proposal
and
NSPI's Supplementary Evidence

May 6, 2005

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Consensus Proposal

In this hearing, fourteen major issues were identified by stakeholders. These were:

a. Precedents to be set by this OATT Hearing
b. Stranded Costs
c. Energy Imbalance
d. Allocation of Revenue Requirement
e. Inclusion of Radial-to-Load Transmission
f. Use of Proxy Units to Develop Some Ancillary Service Charges
g. Rate Design Based on NCP versus LRS
h. Special OATT for Customers Taking Service at 138 kV or Higher
i. Rate Unbundling
j. Available Transmission Capacity (ATC) Calculations
k. Interconnection of Small Generators at Transmission Voltages
l. Refunding Capital Contributions to Network Upgrades
m. Back-Up Service
n. Regional Cooperation

Each of these is addressed in this consensus proposal.

1. Precedents to be set by this OATT Hearing

Some stakeholders, who will not be eligible customers of OATT in the first phase of market opening, are participating in this hearing because of their concerns that this hearing may set precedent and limit their ability to address certain issues when the subsequent stages of market opening occurs. To address this, it is agreed that:

i) The OATT will be reviewed in the event the market is opened more broadly, and in such a review, the decisions made in this proceeding will not be binding and shall not be treated as a precedent in any such subsequent review. Any party will be free to raise any issue in that review and NSPI will not take the position that any matter then under consideration was conclusively decided in this proceeding or determined to be appropriate for any broader market opening.

ii) NSPI acknowledges that some parties will rely on this statement in deciding to withhold making submissions at this time.

2. Stranded Costs

Consistent with FERC's pro forma Open Access Transmission Tariff (OATT), NSPI's proposed Tariff, as filed on May 12, 2004, preserved NSPI's right to seek to recover stranded costs. (Sections 26.0 and 34.5 of the Tariff).

When NSPI filed its Tariff, it undertook to submit a specific proposal to address stranded costs within ninety days, because experience in other jurisdictions indicated that eligible customers were reluctant to use the OATT until their potential stranded cost obligations were known. NSPI filed its proposal on August 10, 2004.

During the technical conferences, and in their pre-filed evidence, stakeholders have expressed the view that, because of the complexity of the stranded cost issue, it should be excluded from the OATT proceeding and addressed separately. To provide certainty for the six municipal utilities who are the only eligible customers during the first phase of market opening, as specified in the Electricity Act, it has been suggested that stranded costs not be calculated for, or payable by, any of those customers.

NSPI agrees with this proposal on the basis that:

a) This proposal does not set a precedent or limit NSPI's right to seek to recover stranded costs from customers, other than the six municipal utilities currently identified in the Electricity Act, in accordance with the OATT.

b) This proposal applies only to the six municipal utilities identified in the Electricity Act, in their present operating territories. NSPI reserves the right to seek to recover stranded costs from any of the six eligible customers whose characteristics change significantly. Without restricting the generality of the foregoing, NSPI will be at liberty to reassess this undertaking in the event of any annexation that would expand a municipal utility's service territory, or if any customer of NSPI (other than former municipal customers who have, by formal agreement, become customers of NSPI in the past, and may revert back to become municipal customers when such agreements expire) becomes a customer of the municipal utility.

c) This proposal does not imply that NSPI accepts or rejects any methodology for the determination and recovery of stranded costs.

d) The proposal applies separately in relation to each of the six municipal utilities.

3. Energy Imbalance

A number of intervenors were concerned with NSPI's proposed Schedule 4 of its evidence dealing with energy imbalance. The issues related to:

- The application of imbalance to both generation and load, rather than dealing with only net imbalance

- The size of the deviation bands
- The multipliers applied to the marginal costs
- The treatment of non-dispatchable generators

On April 14, 2005, FERC released its Notice of Proposed Rulemaking ("NOPR") on the treatment of intermittent (non-dispatchable) generation. This document helped NSPI and other stakeholders further understand the treatment of energy imbalance as applied to load and generation balancing services, and move toward a consensus. NSPI is modifying its energy imbalance proposal to reflect this and is submitting a revised Schedule 4. In summary, the changes are:

- **Settlement on Net Deviation** – Energy imbalance will be applied to the net deviation of generation and load for a bilateral schedule of a single load and its single generator. In other circumstances, separate settlement will apply.
- **Minimum size of the Deviation Band** - The minimum size of the deviation band increases from +/- 1 MW to +/- 2 MW.
- **90% - 110% Buy/Sell spread within the deviation band** –The Buy/Sell spread is eliminated for net energy imbalances within the deviation band. Imbalances that have not been eliminated by the end of the billing month will be settled at either the average marginal cost of peak hours or the average marginal cost of non-peak hours, applied to the residual on-peak and non-peak amounts respectively.
- **90% - 150% Buy/Sell spread outside the deviation band** – The 90/150% spread is changed to 90/110% for settlement of imbalances outside of the deviation band. These are settled based on the marginal cost in the hour of deviation. Changing the 150% charge for under-deliveries outside the deviation band effectively eliminate the network service band and therefore the energy imbalance treatment for both Network and Point-to-Point Service are combined into one section.

- **Treatment of Non-Dispatchable Generators** - A +/- 10% (Minimum +/- 2 MW) Deviation Band for Non-Dispatchable Generators is introduced, within which imbalances are settled at marginal cost in the hour of occurrence. Outside this deviation band, net imbalances are settled at the 90% - 110% of marginal cost in the hour of deviation.
- **Treatment of Dispatchable Generators** – The treatment for "Dispatchable" generators is clarified. All net imbalances are settled at the 90% - 110% of marginal cost in the hour of the deviation.

4. Allocation of OATT Revenue Requirement

In the preparation of its OATT, NSPI allocated revenue requirement between Network and Point-to-Point service on the basis of 12 CP.

UARB consultants Stutz and Fagan expressed concern in pre-filed evidence and IR responses that because this approach is different from NSPI's approved cost of service methodology, it may not be FERC compliant, may not be most appropriate from a cost causation point of view, and may result in a customer who currently takes bundled service paying a different rate for transmission service should that customer become an OATT customer.

At the April 8, 2005 technical conference, Dr. Stutz and Mr. Fagan agreed to reconsider their positions. In subsequent discussions, it was determined that:

- Future exports using point-to-point service are uncertain. Some assumption is necessary to establish a rate for point-to-point service. For the purposes of this OATT, NSPI used the average of the last five years, assuming equal exports in all hours.
- For the assumptions made, and for reasonable variations of those assumptions, the results of the allocation are similar, whether the allocation is done using the cost of service method or the 12 CP method.

Based on these facts, it was agreed that 98% of the revenue requirement would be allocated to Network Service and 2% would be allocated to Point-to-Point Service. Based on current assumptions of transmission system usage, these results are consistent with either the cost of service approach or the 12 CP approach. Acceptance of these results does not endorse either method of deriving them.

5. Inclusion of Radial-to-Load Transmission

NSPI proposes to include all transmission (except direct-assigned facilities) in its OATT revenue requirement. SEB consultant Rosenberg recommended radial-to-load transmission should be excluded from OATT.

In light of the position on precedent not being set in this hearing, SEB is no longer taking a position on this issue in this hearing. No other party has suggested a position different from NSPI's proposal.

6. Use of Proxy Units to Develop Some Ancillary Service Charges

NSPI proposed in its OATT to calculate prices based on proxy units for the following ancillary services:

Load Following and Regulation

Reactive Supply and Voltage Control

Reserve – Spinning

Reserve – Supplemental

UARB consultants Stutz and Fagan proposed basing these prices on embedded costs, reflecting the costs of the units that actually supply these services. NSPI agrees to price its ancillary services on embedded costs, as derived in Exhibit 4 and updated in NSPI's Supplementary Evidence of May 5, 2005.

7. Rate Design Based on NCP versus LRS

NSPI proposes to calculate its OATT rates using Non-coincident Peak as the customer's billing determinant. SEB consultant Rosenberg recommended that the rate should be designed using Load Ratio Share.

In light of the position on precedent not being set in this hearing, SEB is no longer taking a position on this issue in this hearing. No other party has suggested a position different from NSPI's proposal.

8. Special OATT for Customers Taking Service at 138kV or Higher

NSPI proposes to include all transmission in its OATT. SEB consultant Rosenberg recommended a separate OATT rate for customers taking service at 138Kv or higher.

In light of the position on precedent not being set in this hearing, SEB is no longer taking a position on this issue in this hearing. No other party has suggested a position different from NSPI's proposal.

9. Rate Unbundling

Some stakeholders expressed concern that NSPI's proposal to provide OATT information to all customers eligible to use OATT would not be sufficient to allow those customers to make a decision as to whether or not to seek competitive supply, and that unbundling of rates was necessary. After reviewing a sample of the bill information proposed by NSPI, stakeholders agreed the information was sufficient and that unbundling was not required for this market opening.

10. Available Transmission Capacity (ATC) Calculations

NSPI proposes to use the NPCC methodology for ATC calculations, recognizing that:

- NSPI and NBSO jointly determine TTC/ATC based on conditions on their respective transmission systems, and the more restrictive of the two determinations rules;
- Nova Scotia import is constrained by conditions such as load in Moncton, export to PEI or transmission out of service in NB, up to a maximum level of NS underfrequency load shedding; and
- Nova Scotia export is limited by load level in Northern NS, the size of the largest single load loss, and the amount of generation armed for rejection by the Export Monitor Special Protection System.

The proposed method of calculating ATC has been accepted by stakeholders.

11. Interconnection of Small Generators at Transmission Voltages

NSPI's proposed interconnection procedures apply to all generators connecting to the transmission system. As noted by UARB consultant Fagan, FERC allows a simpler approach to generators smaller than 20MW who connect to the transmission system. He suggests that NSPI also allow a simpler approach.

NSPI's interconnection procedures as filed allow NSPI to simplify the process when appropriate, and NSPI's practice reflects this. To make the process more transparent, NSPI is adding the following new Section 2.5 to its interconnection procedures (Exhibit 2):

"In assessing whether the interconnection process can be expedited, the Transmission Provider will consider the capacity of the Generation facility, the point of interconnection requested, and the results of any previously completed System Impact Studies which may be relevant. If the process is expedited, the transmission Provider will:

- Forego the Feasibility Study
- Combine the System Impact Study and the Facilities Study
- Eliminate the requirement for coordination with Affected Systems
- Modify the System Impact Study scope to exclude stability analysis."

Revised pages reflecting this change are included in NSPI's Supplementary Evidence.

12. Refunding Capital Contributions to Network Upgrades

NSPI's proposed Standard Generation Interconnection Procedures (SGIP) do not address the repayment of capital contributions by an interconnecting customer to network upgrades. As noted by UARB consultant Fagan, FERC addressed this issue in Orders 2003, 2003-A and 2003-B.

NSPI is addressing this issue by adopting the FERC approach, as described below, and is modifying Section 11.4.1, Appendix 6, its SGIP accordingly:

"Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Generating Facility. Any repayment shall include interest from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date:

(1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or

(2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an

alternative schedule that is mutually agreeable and provides return of all amounts advanced for Network Upgrades not previously repaid; however full reimbursement shall not extend beyond (20) years from the Commercial Operation Date

If the Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades.

Before such re-imbursement can occur, the Interconnection customer, or the entity that ultimately constructs the generating facility, if different, is responsible for identifying the entity to which reimbursement must be made."

Revised pages reflecting this change are included in NSPI's Supplementary Evidence.

13. Back-up Service

The EMGC defined Back-up Supply Service as "The provision of capacity and energy to a market participant, either when needed to replace the loss of its generation sources, or to cover that portion of demand that exceeds the generator's capacity to supply for more than a short time".

NSPI's proposed OATT addresses the second component of the EMGC's back-up service by allowing partial service. This is supported by all parties.

NSPI currently offers its Generation Replacement rate to address the first component of EMGC's back-up service, and has agreed to develop a rate to provide firm back-up service should it be requested. In addition, NSPI's OATT permits an OATT customer to negotiate with alternate suppliers to provide such service. Stakeholders have agreed that these options are outside the scope of the OATT.

14. Regional Cooperation

In its pre-filed evidence, NBSO agrees that there is consistency between the NBSO OATT and the NSPI OATT, but expresses the view that:

- the UARB should direct NSPI to "actively pursue regional cooperation in order to achieve costs savings" in certain OATT ancillary service charges.
- the UARB "direct NSPI to modify OATT to accommodate a mechanism for limiting the quantity of capacity -based ancillary services that can be self supplied".

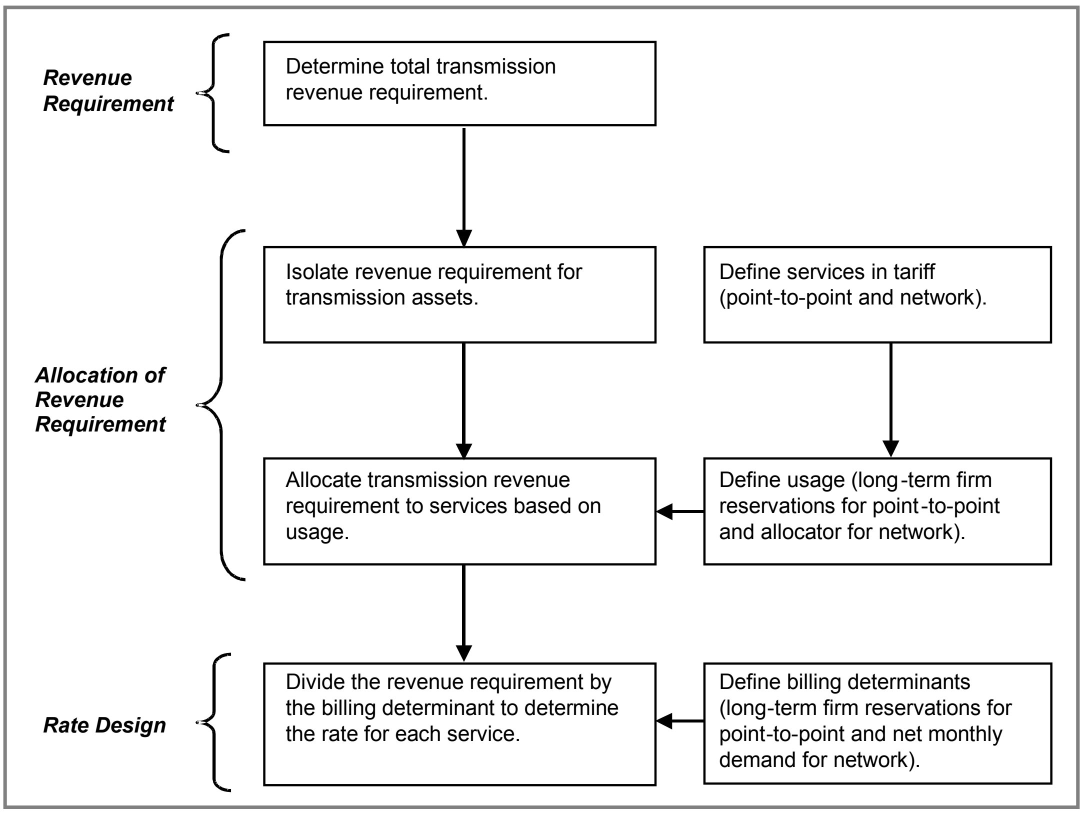
In view of NSPI's registration with NERC on April 1, 2005 as a "balancing authority", in light of the NB PUB decision regarding NBSO's OATT on April 26, 2005 (subsequent to the filing of NBSO's evidence in this hearing), which modified or delayed a decision on some of NBSO's proposals for New Brunswick that relate to its evidence in this hearing, and given the ongoing efforts of NSPI and NBSO in regional cooperation for mutual benefit, the parties have agreed that the issues raised here should be deferred from this hearing and addressed as part of the ongoing efforts of the parties to identify and implement opportunities beneficial to customers in both jurisdictions in a timely manner.

5.0 Transmission Services Revenue Requirement and Rate Design

The transmission tariff defines the terms, conditions and price under which an Eligible Customer can gain access to the Transmission System. The methodology of developing efficient and equitable tariff rates can be simplified to the three-step process illustrated in Figure 5-1.

Figure 5-1

Overview of the Steps taken in the Development of Rates



5.1 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 Transmission Services. The total revenue requirement related to NSPI's Transmission System has been determined to be \$82.8 million for 2005, as derived in Exhibit 3. This revenue requirement includes all costs (depreciation costs, operation and maintenance costs, finance charges, and taxes) plus a regulated return on equity of 9.55%, the mid-point of the range currently approved by the Board. The components of the revenue requirement are summarized in Figure 5.2.

Figure 5-2

Transmission System Revenue Requirement

Revenue Requirement Component	**$millions**
Depreciation	17.20
O&M including overhead costs	19.02
Interest, taxes and return on equity	46.56
Total	82.78

The revenue requirement shown in Figure 5.2 includes the costs of all transmission lines at voltages of 69 kV or higher and the terminal stations associated with those transmission lines. It also includes the revenue requirement associated with the generation step up transformers of NSPI's generators.

5.2 Allocation of Revenue Requirement

The purpose of the revenue requirement 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 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, and

- Allocation of the functional costs to the Transmission Services.

5.2.1 Services Defined in Tariff

Two basic Transmission Services will be available under the OATT. Both are consistent with the FERC *pro forma* tariff. They are 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 Point-to-Point Service and Network Service, and the Scheduling, Control and Dispatch service is considered here in Section 5, while the rates for the other Ancillary Services are detailed in Section 6.

<u>Point-to-Point Service</u> refers to the reservation of capacity (for a specified period of time and a specified number of MW) to allow the transmission of energy from a Point of Receipt to a Point of Delivery. An example of this would be a one-month reservation of 100 MW from a generator inside Nova Scotia (the Point of Receipt) to the New Brunswick interconnection (the Point of Delivery). This service is available on either a firm or a non-firm basis.

<u>Network Service</u> 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.

Scheduling, System Control, and Dispatch Service is the process through which the system operator ensures that scheduled transactions are executed. It is required to schedule the movement of power into, out of, or within Nova Scotia. Only the NSPI System Operator can provide this service.

5.2.2 Transmission Functions

The services defined in the OATT and described in the previous section use different parts of the Transmission System. This was considered by the EMGC. In its final report, the EMGC recommended that only those transmission costs associated with the provision of each service should be allocated to that service. EMGC Recommendation 26 provides:

> *The EMGC recommends using the following principles to determine whether the costs of transmission facilities should be included in the transmission tariff:*
>
> - *The cost of a transmission facility used solely by one party should be assigned or charged to that party.*
> - *The cost of transmission facilities that are not part of the transmission backbone should be directly assigned or charged to those parties that use them. The preferred alternative for realizing this objective is:*
>   - *Costs for radial lines serving generators be assigned to those generators*
>   - *Costs for generation step-up transformers be assigned to those generators*
>   - *Costs for radial lines serving distribution loads be assigned to distribution, the revenue requirement to be recovered uniformly from all distribution level customers, supplied by both NSPI and the municipal utilities.*

To ensure appropriate cost allocation, it is necessary to break down the revenue requirement into component pieces. Only after such a breakdown is completed can costs be allocated to specific services.

This section identifies which assets are used to provide which services. For the purposes of the NSPI OATT, assets have been grouped into three main functional groups as follows:

- Generation Related Transmission Assets
- Bulk Network Assets which can be further subdivided into:
    - Interconnections
    - In-province network
- Radial-to-Load Assets

In order to perform this allocation of 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.

<u>Generation Related Transmission Assets ("GRTA")</u> are those assets that serve the function of connecting generation units to the shared Transmission System. They consist of generator step up transformers ("GSU"), a portion of substation assets, and transmission lines whose primary purpose is to connect a generator to the Transmission 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 will be responsible for the cost of any additional transmission assets that are required to connect the new generator, including, but not limited to, additional transmission capacity and reliability investments. In the FERC *pro forma* tariff, as well as in the proposed NSPI OATT, these assets are referred to as Direct Assignment Facilities.

<u>Bulk Network Assets</u> 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 transmission lines that interconnect with NB Power at the provincial border. The in-province assets consist of all transmission lines that operate as part of the integrated system within the province.

Radial-to-Load Assets are those parts of the Transmission System that are not a part of the integrated network and are used only to serve in-province loads. The costs associated with these parts could be pooled and charged in a different fashion than the highly shared bulk network, as recommended by the EMGC[1]. Since these radial lines may also serve industrial loads, however, excluding them from the bulk power network would create discriminatory service if and when the Transmission System is open to industrial customers, because some of the assets needed to serve industrials would be excluded from the tariff. In addition, the status of radial-to-load assets may change if new generation is connected to such lines. These situations could be addressed when they occur by redefining radial-to-load at that time. However, because the impact of including radial-to-load as part of the bulk power network is not large, and to avoid having to revise the tariff each time the status of radials-to-load changes, NSPI is proposing to include radial-to-load assets with the bulk power network assets.

[1] See EMGC Recommendation 26 which recommends lines serving distribution load be assigned to distribution.

5.2.3 Functional Allocation of Costs

The allocation of the Transmission Services revenue requirement of $82.78 million to the functional uses of the system is detailed in Figure 5-9. The results are summarized in Figure 5-3.

Figure 5-3

Functional Allocation of Revenue Requirements

Functional Use	Revenue Requirement Share ($millions)
Generator Related Transmission Assets (GRTA)	4.96
Bulk Network In Province	73.06
Energy Control Centre	4.76
TOTAL	82.78

As described above, these costs are being assigned as follows:

- All GRTA's, including GSU costs and non-GSU costs, are directly assigned to generators, i.e., they are not recovered through OATT ($4.96 million).

- Interconnections, in-province bulk network and radial-to-load 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 ($73.06 million).

- Energy Control Centre costs are allocated to Scheduling, System Control and Dispatch and are to be collected through tariff rates for that service ($4.76 million).

5.2.4 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 is to select metrics for each of the services such that the cost allocation meets the appropriate rate making principles. The "cost causation" and "used and useful" principles are the two most relevant to the issue of what usage to apply in the allocation of revenue requirements.

The principle of "Cost Causation" seeks to allocate cost in a manner that is reflective of the customer characteristics that cause the costs to be incurred. The "Used and Useful" principle reflects the notion that only assets used to serve a customer are charged to that customer and that the allocation adequately reflects appropriate usage. At the same time, the "Used and Useful" principle would seek to ensure that all customers using the Transmission System pay a fair and reasonable share of transmission costs.

The allocation of the transmission revenue requirement in the NSPI cost allocation to Point-to-Point and Network Services is 2% and 98% respectively, based on the consensus proposal. It is consistent with the approach prescribed by FERC in Order 888, and also with NSPI's cost of service methodology. The FERC 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.

With respect to Point-to-Point Service, FERC substitutes Point-to-Point reservations for actual use, 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 NSPI system, there are not yet any long-term firm Point-to-Point reservations. However, NSPI's exports over the last five years, averaged across all hours, has been 34 MW.

The resulting system usage is shown in Figure 5-4.

Figure 5-4

Transmission System Usage

Usage	Quantity (MW)
Long-term reservations	34
Forecasted average of Network Loads at the time of the 12 monthly system peaks in 2005	1823
Total	1857

5.2.5 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 5.2.3 as $73.06 million/year. This revenue requirement is allocated to the different Transmission Services based on the consensus proposal. Applying 2% for Point-to-Point reservations and 98% for Network Service, the allocation of costs to these services is shown in Figure 5-5.

Service	Share	Revenue Requirement ($ millions)
Point-to-Point	2%	1.46
Network	98%	71.60
Total	100%	73.06

The revenue requirement for each service can also be expressed on a per-unit of usage basis as shown in Figure 5-6. The $/MW-year figures given represent the per-unit cost of providing each of the services based on the application of the transmission pricing principles.

Figure 5-6

Per Unit Transmission Services Revenue Requirements

Service	Revenue Requirement ($ millions)	Usage (MW)	Per Unit Revenue Requirement ($/MW-year)
Point-to-Point	1.46	34	42,970.59
Network	71.60	1823	39,278.11
Total	73.06	1857	

5.3 Rate Design

Now that costs have been allocated to specific services it is possible to design rates to recover these costs. This is the third step referred to in Figure 5-1. This design of rates involves the following:

- Selection of a rate structure,
- Selection of billing determinants for each service, and
- 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 Revenue Requirement Allocation has been considered.

5.3.1 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 mailed and delivered within the same country are typically at a fixed price, regardless of their destination within the country. 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. NSPI's proposed approach is a postage stamp rate as recommended by EMGC Recommendation 29:

> *The EMGC recommends that the transmission tariff rate design be based on a consistent charge regardless of the location of the connecting customer...*

The postage stamp rate structure recommended by EMGC is the structure applied in the FERC Order 888 *pro forma* tariff. This approach was also adopted in Saskatchewan, Manitoba, Quebec and New Brunswick. Alberta and Ontario do not use pro forma based tariffs, and British Columbia applies postage stamp to Network Service but Point-to-Point service is priced by the zone in which the Point of Delivery is located.

The adoption of a postage stamp rate approach means that Transmission Customers will pay the same rate for Transmission Service regardless of the Point of Delivery.

5.3.2 Definition of Billing Determinants

In order to determine the price that will be charged to users of a particular service, 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.

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 lead to cross subsidization for Transmission Services of low load factor customers by other customers.

Another billing determinant is kW of demand. This can be defined as coincident demand (i.e., the customer's demand at the time of the peak system load) or non-coincident demand (i.e., the customer's maximum demand in a given month, regardless of when that demand occurs).

In-province customers of NSPI are 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. It could also support coincident peak billing for some customers, since all existing wholesale customers (i.e., municipals) and all customers whose demand exceeds one MVA have interval meters that capture the hourly peak readings. However, in the context of the proposed OATT, where NSPI is considered an OATT customer with multiple delivery points, metering exists on only 77% of the interfaces between the transmission and our own distribution system. None of this metering is of revenue quality and none of it is interval metering.

The FERC *pro forma* tariff uses load ratio share ("LRS") as the billing determinant for Network Service, based on the customer's coincident peak demand. In any month, each user of Network Service is billed its share of the total monthly revenue requirement on the basis of its LRS which is defined as follow:

LRS = (Sum of Network Customer's Rolling 12 Monthly Coincident Demands) divided by the (Sum of Rolling 12 Monthly System Peak Demands)

Each expected Eligible Customer (e.g., the municipal electric companies) under OATT (except NSPI) currently has the metering necessary to implement this approach, and the total peak loads on the Transmission System are known to NSPI through our Supervisory Control and Data Acquisition ("SCADA") system. This means that the LRS for each Eligible Customer could be calculated. However, the principal disadvantages of this approach are:

- Customers who are able to control their loads at the time of monthly coincident peak could (theoretically, at least) have an LRS of zero, in which case they would receive free Network Service, even though they use the Transmission System most hours during the month. Alternatively, customers who cannot control load and have a high coincidence factor, could pay a disproportionate share of transmission cost.

- Load control actions taken by one customer impact the bills of other customers. It, therefore, takes control of this cost away from the customer and makes the monthly bill less predictable.

- This approach is inconsistent with what customers in Nova Scotia are accustomed to.

Because of these disadvantages, NSPI proposes to use monthly non-coincident peak ("NCP") demand as the billing determinant for Network Service and not LRS. The NCP demand for all Eligible Customers (except NSPI) is available from existing metering. Given the lack of complete metering, we propose to use a coincidence factor to derive NSPI's NCP demand from the known coincident peak demand. NSPI estimates this coincidence factor to be 85.0%. This coincidence factor was determined from the available hourly load data for load connected to the Transmission System (distribution substations, municipal load, and industrial load). Fifty-eight substations, representing approximately 64% of NSPI's load are monitored via either SCADA or in the case of customers connected to the transmission system, interval meters. To determine the total system coincidence factor, it was necessary to estimate the non-coincident monthly peak demand for the unmonitored substations. The hourly load data for the monitored substations was analyzed for 2002 and 2003 to determine average monthly coincident factors by substation type (i.e., industrial, residential/commercial, urban versus rural). The appropriate coincidence factors from this analysis were applied to the monthly coincident peak loads for the non-metered load (non-metered coincident load was calculated from total monthly coincident peak load minus monthly coincident metered load), to determine the non-coincident demands for the non-metered substations.

Another aspect of billing for transmission that relates to self-generating customers is the 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.

The EMGC addressed the issue of billing determinants in its Recommendation 28:

> *The EMGC recommends that the billing determinants to establish charges for network customers be monthly net non-coincident peak demand and that for point-to-point customers it should be reserved capacity (estimated on a net load basis, if necessary). The charge basis for existing self-generation customers would be hourly net non-coincident peak.*

NSPI proposes to follow the EMGC recommendation with respect to Network Service. For Point-to-Point Service, the billing determinant will be the transmission capacity reserved by the customer.

5.3.3 Determination of Rates

Given that the revenue requirement and billing determinants have been defined for each service, the nominal rate is the revenue requirement for the service divided by the respective billing determinant. Figure 5-7 illustrates the calculation of the nominal annual rate for each service.

Figure 5-7

Determination of Nominal Rates by Service

Services	Revenue Requirement ($millions/yr)	Billing Determinant (MW)	Nominal Rate ($/MW/yr)
Point-to-Point Services			
Transmission	1.461	34	42,970.59
Schedule,Control&Dispatch	0.095		2,794.12
Network Services			
Transmission	71.604	2,145*	33,381.82
Schedule,Control&Dispatch	4.663		2,173.89
* 1823 ÷ 0.85 = 2145 MW			

For Point-to-Point Service, it is 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[2] and is used in Saskatchewan, Manitoba, Quebec and New Brunswick.

[2] 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 proposed by NSPI 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 Daily rates apply to service taken Monday to Friday, and Off-Peak Daily service is used on Saturday and Sunday. Since Point-to-Point Service will primarily be used for exports from Nova Scotia, On-Peak hours are defined by NSPI as the time between 08:00 and 24:00 Atlantic Time, Monday to Friday to coordinate with NB Power and power markets in the Eastern Time Zone. 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 five and the On-Peak Hourly rate is the On-Peak Daily rate divided by sixteen.

NSPI has proposed 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 revenue requirement allocation analysis, and the design of the end use rates just described, the rates proposed by NSPI for approval by the Board are set out in Figure 5-8.

Figure 5-8
Summary of Transmission Service Rates

Services	Units	Transmission Service	Scheduling, System Control & Dispatch
Point-to-Point			
– Yearly	$/MW-yr	42,970.59	2,794.12
– Monthly	$/MW-m	3,580.88	232.84
– Weekly	$/MW-w	826.36	53.73
– On-Peak Daily	$/MW-d	165.27	10.75
– Off-Peak Daily	$/MW-d	117.73	7.66
– On-Peak Hourly	$/MW-h	10.33	0.67
– Off-Peak Hourly	$/MW-h	4.91	0.32
Network	$/MW-m	2,782.20	181.18

Additional details with respect to the derivation of these rates are provided in Figures 5-9 to 5-14.

5.3.4 Power Factor Penalty in the Transmission Tariff

Power factor is the ratio between MW and MVA. A load such as an incandescent light bulb or a baseboard electric heater has a high power factor (1.0). A typical motor or fluorescent light has a lower power factor. A load with a power factor less than 1.0 will consume reactive power, previously explained as being measured in Volt-Amperes Reactive (“VAR”).

A power factor that is excessively low results in unacceptable transmission voltage and requires the production of reactive power. NSPI's bundled rates for industrials, municipal utilities and large commercial customers recognize this effect and include penalties for low power factor.

NSPI's OATT includes a power factor penalty that will be applied for any month in which a Transmission Customer has a power factor of less than 0.90. Under the tariff proposal the penalty paid shall be based on Excess kVA, where Excess kVA shall be defined as:

Excess kVA =	Max. kVA – Max. kW / 0.9
Where Max. kVA =	Maximum kVA consumed during the month
Max. kW =	Maximum kW consumed during the month

The charge per Excess kVA will be the demand charge of the NSPI Large Industrial Rate, which is currently $7.47/kVA.

FIGURE 5-9

NOVA SCOTIA POWER INC.
TRANSMISSION REVENUE REQUIREMENT ALLOCATION
(in $000s)

Asset Category	(1) Gross Plant (Note 1)	(2) Net Plant (Note 1)	(3) OM&G Expense	(4) Depreciation Expense	(5) Int., Taxes & Return Exp	(6) Total Expenses
Generation Related Transmission Assets:						
Step Up Transformers	$17,619	$10,045	$371	$455	$1,228	$2,054
Radial to Generation	17,460	9,954	368	451	1,217	2,036
Generator Breakers	7,427	4,234	157	192	517	866
Total Gen. Related Transmission Assets	42,506	24,234	896	1,098	2,962	4,956
Bulk Network:						
Total Equipment	636,797	356,733	13,367	16,101	43,597	73,065
Total Transmission Assets	**$679,303**	**$380,967**				
Scheduling, System Control & Dispatch (Note 2)			4,758			4,758
Total Transmission Revenue Requirement			**$19,021**	**$17,199**	**$46,559**	**$82,779**

NOTE:

1. Transmission Gross and Net Plant assets include allocated share of General Property assets and other assets such as deferred charges, materials inventory and net receivables.
2. Control Centre assets and related capital charges are included in the General Property assignment to Transmission assets.

(Revised May 2005)

FIGURE 5-10

NOVA SCOTIA POWER INC.
DEMAND ALLOCATION FACTORS
(in MW Demand)

Service	(1) Long-Term Firm Reservations	(2) Transmission System 12 CP	(3) Allocation Factors (%)	(4) Billing Determinants 12 NCP
Point-to-Point (Note 1)	34		2%	N/A
Network In-Province (Note 2)		1,823	98%	2,145
TOTAL MW	**34**	**1,823**	**100%**	

NOTES:
1. NSPI currently has no long-term firm reservations. However, exports have averaged 34 MW over the past 5 years.
2. The 1823 MW is the average of the 12 monthly Coincident System Peaks forecasted for 2005 and developed in April 2004 as part of NS Power's 2005 Rate Application. The 2145 MW was derived by applying an 85% coincidence factor to the 12 monthly System Coincident Peaks. This coincident factor was based on 2003 system load data.

(Revised May 2005)

FIGURE 5-11

NOVA SCOTIA POWER INC.
TRANSMISSION REVENUE REQUIREMENT ALLOCATION
UNIT COSTS

Transmission Services	(1) Total Cost By Service (in $000s)	(2) Total Usage By Service (in MW)	(3) Annual $/MW-year	(4) Monthly $/MW-month
Point-to-Point Service	$1,461	34	$42,970.59	$3,580.88
Network Service	71,604	1,823	$39,278.11	$3,273.18
Total Transmission	**73,065**	**1,857**	**$39,345.72**	**$3,278.81**
Scheduling, System Control & Dispatch				
Point-to-Point Service	95	34	$2,794.12	$232.84
Network Service	4,663	1,823	$2,557.87	$213.16
Total Scheduling, System Control & Dispatch	**$4,758**	**1,857**	**$2,562.20**	**$213.52**

NOTES:
1. Point-to-Point and Network Transmission Service costs are Bulk Network Costs from Figure 5-9 and allocated using the allocation factors from Figure 5-10.
2. Scheduling, System Control & Dispatch Service costs, from Figure 5-9, are allocated using the allocation factors from Figure 5-10.

(Revised May 2005)

FIGURE 5-12

NOVA SCOTIA POWER INC.
RATE CALCULATION
POINT-TO-POINT TRANSMISSION SERVICE

Service Category	(1) Total Cost By Service (in $000s)	(2) Total Usage By Service (in MW)	(3) Annual $/MW-year	(4) Monthly $/MW-month
Point-to-Point Service	$1,461	34	$42,970.59	$3,580.88

			RATES $/MW-year	RATES $/MW-month
Yearly		Monthly Cost * 1000	42,970.59	3,580.88
Monthly	($/MW-m)	Yearly/12		3,580.88
Weekly	($/MW-w)	Yearly/52		826.36
On-Peak Daily	($/MW-d)	Weekly/5		165.27
Off-peak Daily	($/MW-d)	Yearly/365		117.73
On-Peak Hourly	($/MW-h)	Daily/16		10.33
Off-Peak Hourly	($/MW-h)	Yearly/8760		4.91

NOTES:
1. Yearly Service is available only as firm service.
2. Hourly Service is available only as non-firm service.
3. Other Services are available as firm or non-firm services.

(Revised May 2005)

FIGURE 5-13

NOVA SCOTIA POWER INC.
RATE CALCULATION
NETWORK TRANSMISSION SERVICE

Service Category	(1) Annual Cost of Service ($MW-year)	(2) Monthly Cost of Service ($MW-month)	(3) Coincidence Factor	(4) Monthly ($MW-month) Billing Rate
Network Service	$39,278.11	$3,273.18	85.0%	$2,782.20

NOTE:
This approach facilitates the use of non-coincident peaks for billing purposes consistent with EMGC Recommendation 28.

(Revised May 2005)

FIGURE 5-14

NOVA SCOTIA POWER INC.
RATE CALCULATION
SCHEDULING, SYSTEM CONTROL AND DISPATCH

	(1)	(2)	(3)	(4)
Service	**Total Cost of Service (in $000s)**	**Total Usage (in MW)**	**Yearly Cost $/MW-year**	**Monthly Cost $/MW-month**
Sched., Sys. Cntrl. & Disp. for Point-to-Point	$95	34	$2,794.12	$232.84

			Rate for Services Billed Monthly	
		Services	**$/MW-year**	**$/MW-month**
Yearly		Monthly Cost	2,794.12	232.84
Monthly	($/MW-m)	Yearly/12		232.84
Weekly	($/MW-w)	Yearly/52		53.73
On-Peak Daily	($/MW-d)	Weekly/5		10.75
Off-peak Daily	($/MW-d)	Yearly/365		7.66
On-Peak Hourly	($/MW-h)	Daily/16		0.67
Off-Peak Hourly	($/MW-h)	Yearly/8760		0.32

	Cost of Service					
	Total Cost of Service (in $000s)	**Total Usage (in MW)**	**($MW-year)**	**($MW-month)**	**Coincidence Factor**	**Rate Monthly ($MW-month)**
Sched., Sys. Cntrl. & Disp. for Network Service	$4,663	1823	$2,557.87	$213.16	85.0%	$181.18

NOTE:
This approach facilitates the use of non-coincident peaks for billing purposes consistent with EMGC Recommendation 28.

(Revised May 2005)

6.0 Ancillary Services Rate Design

As noted in Section 4.2, Ancillary Services are the support services that are required to enable the Transmission System to transmit energy while maintaining reliable operation of the system in accordance with Good Utility Practice. 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 at design voltages and frequency.

This section addresses the development of rates for all of the Ancillary Services that are provided from generators under the control of the System Operator 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 5. The Ancillary Services provided from generators and discussed in this Section can be grouped into two main categories: (1) Capacity based services provided from generation capacity that must be committed to the provision of the service and cannot be used at the same time for other purposes. (2) Non-capacity based services that do not require the commitment of generator capacity for provision of the service.

6.1 Capacity Based Ancillary Services

Capacity based services are defined and provided in the tariff consistent with the numbered schedules used in the FERC *pro forma* tariff. These services are:

- Regulation and Frequency Response from Generation Sources Service (Schedule 3 in the OATT, Exhibit 1), composed of:
  - Regulation; and
  - Load Following
- Operating Reserve – Spinning Reserve Service (Schedule 5 in the OATT)

- Operating Reserve – Supplemental Reserve Service (Schedule 6 in the OATT), composed of:
    - Supplemental (10-minute); and
    - Supplemental (30-minute)

The costs of supplying these services can be calculated from the embedded costs of existing generating units, or they can be calculated using proxy units. NSPI proposes to base the cost of these services on embedded costs in accordance with the consensus proposal. These are derived in Exhibit 4. However, the costs of these services based on proxy units are derived in this section.

The revenue requirement for capacity based services (Schedule 3, 5 and 6 in the OATT, Exhibit 1) 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.

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 5.

Although we are proposing to price Ancillary Services on the basis of proxy units, prices based on the embedded costs of existing units, prices based on proxy units have also been calculated. These prices are compared in Figure 6-1:

Figure 6-1

Comparison of Proxy and Embedded Cost Methodologies

Service	Proxy Method		Embedded Cost Method	
	$/kW-y	$millions/y	$/kW-y	$millions/y
Reactive Supply & Voltage Control		8.1		6.8
Regulation	43.05	1.1	77.82	2.0
Load Following	43.05	6.1	81.53	11.6
Reserve – Spinning	77.49	1.9	94.63	2.4
Reserve – Supplemental 10 min	53.60	5.4	52.49	5.2
Reserve – Supplemental 30 min	53.60	2.7	100.66	5.0
Total		$25.3		$33.0

As shown above, the total annual revenue requirement for Ancillary Services is higher when calculated using embedded costs than it is when calculated using proxy units.

The two key guiding principles in the selection of proxy units were (1) the technical capability of a facility to provide a service and (2) the simplicity of the modeling. A proxy price would not be meaningful if it could not reasonably be argued that such a unit could 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.

6.1.1 The Choice of Proxy Units

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 122 MW combined cycle gas generation plant was selected as the proxy unit for the on-line services. The 122 MW configuration provides reasonable economies of scale and is a proven technology. 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. 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 OATT, Exhibit 1) a 183 MW simple cycle gas turbine was used as the proxy to be consistent with the unit used to calculate the credit to interruptible customers. 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 lower 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.

The costs for the proxy unit to provide the capacity based Ancillary Services are summarized in Figures 6-5 and 6-6.

6.1.2 Requirements of Capacity Based Ancillary Services

NSPI, as the Transmission Provider, has a responsibility to operate in accordance with NERC and 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 NSPI OATT obligates NSPI, as the Transmission Provider to make all Ancillary Services available to all Transmission Customers. Therefore, NSPI must be able to procure adequate generation resources to do so.

Transmission Customers can purchase each of the Ancillary Services from the Transmission Provider (NSPI) 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. The NSPI system requirements for “Regulation and Frequency Response” and “Operating Reserves” are outlined below.

6.1.2.1 Regulation and Frequency Response

Historical operating experience was used to determine the amount of capacity that is required to provide the Regulation and Frequency Response Ancillary Service. Nova Scotia load has two characteristics that dictate the requirements of this Ancillary Service: minute-by-minute load fluctuations (Regulation), and the change in load from hour to hour (Load Following). The minute-by-minute fluctuations require 26 MW of generation capacity for the Nova Scotia system, and the hour-to-hour change in load requires 142 MW of generation capacity.

6.1.2.2 Operating Reserves

NPCC defines the requirement for Operating Reserves in the Maritimes Control Area. Under the terms of our Interconnection Agreement with NB Power, NSPI is obligated to provide its share of Operating Reserves as follows:

Spinning Reserve	25 MW
10 Min (non spinning) Reserve	100 MW
30 Min Reserve	50 MW

This means that at all times, NSPI must have: 25 MW of spare capacity available from units already on line, 100 MW of capacity (or load reduction) that can be made available within 10 minutes, and an additional 50 MW of capacity (or load reduction) that can be made available within 30 minutes.

6.1.3 Summary of Revenue Requirements for Capacity Based Ancillary 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 Figure 6-2.

Figure 6-2

Revenue Requirement of Capacity Based Ancillary Services

Services	Revenue Requirement ($/kW-yr)	Services Required (MW)	Revenue Requirement ($1000/yr)
Regulation	43.05	26	1,119.35
Load Following	43.05	142	6,113.35
Spinning (10-minute)	77.49	25	1,937.33
Supplemental (10-minute)	53.60	100	5,360.16
Supplemental (30-minute)	53.60	50	2,680.08

Additional detail with respect to the derivation of these revenue requirements are provided in Figures 6-6 to 6-8.

6.1.4 Capacity Based Ancillary 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 and Network Services 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 customers taking Network Service, are billed at the monthly rate at the end of each calendar month as noted in the terms and conditions of the OATT. 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 Figure 6-3 and detailed in Figure 6-8.

Figure 6-3

Nominal Rates for Capacity Based Ancillary Services

Service	Revenue Requirement ($1000/yr)	Usage (MW)	Rate $/MW-month
Regulation	1,119.35	2,145	43.49
Load Following	6,113.35	2,145	237.50
Operating Reserve – Spinning	1,937.33	2,145	75.27
Operating Reserve – Supplemental (10-minute)	5,360.16	2,145	208.24
Operating Reserve – Supplemental (30-minute)	2,680.08	2,145	104.12

6.2 Non-Capacity Based Ancillary Services

Non-capacity based Ancillary Services are:

- Scheduling, System Control and Dispatch (Schedule 1 in the OATT, Exhibit 1),
- Reactive Supply and Voltage Control Service (Schedule 2 in the OATT), and
- Energy Imbalance Service (Schedule 4 in the OATT).

The three-step methodology for developing rates (outlined in Figure 5-1) 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 5 of this report. The remaining two non-capacity based Ancillary Services are considered below.

6.2.1 Reactive Supply and Voltage Control Service

The proxy selected for this service are SVC's. SVC's are considered to be an appropriate choice for these reasons:

- NSPI has extensive experience with SVC's, with a major installation at Brushy Hill since 1984.

- If dynamically controlled reactive power is required in the future, an SVC or similar technology would be the most likely candidate for NSPI.

- NB Power based its proxy unit for this service on a "synchronous condenser" which is similar to the type of generator commonly used, but without a turbine driving it. Although synchronous condensers can provide reactive power, they are not commonly available since the advent of SVC technology. The primary advantage of a synchronous condenser over an SVC was its ability to improve the stiffness of the Transmission System where high-voltage direct current ("HVdc") systems are connected to weak networks. Improvements in HVdc technology have all but eliminated this application.

- SVC's have a speed of response and stability enhancing characteristics similar to the static excitation systems on the most recently installed large generators, but have lower losses than a synchronous condenser.

Reactive power must be appropriately distributed across the Transmission System, since it cannot be transported efficiently. If there was no reactive power available from generation, SVC's of a wide range of sizes would have to be strategically deployed across the grid to provide this Ancillary Service.

The total system requirement for this service from generators on the system is based on the reactive power output of in-province generators at the time of system peak plus an additional MVAR capability held in reserve to ensure dynamic system security. The total revenue requirement for this service is determined by applying the proxy unit cost to the total system requirement for reactive power. Details of this are provided in Figure 6-9.

Whether purchasing Point-to-Point or Network Service, all Transmission Customers use this service, since without this service no transactions can occur. Therefore, the revenue requirement 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 5.2. 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 5.3. 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 non-coincident peak net demands for Network Service. The Appalachian pricing approach (explained in Section 5.3.3) is applied to this service in the same fashion as it is applied to the Point-to-Point Service. The rates for this service, as derived in Figure 6-10, are shown below.

Figure 6-4

Reactive Supply and Voltage Control Service Rates

Services	Units	Rate
Yearly	$/MW-yr	4,744.27
Monthly	$/MW-m	395.36
Weekly	$/MW-w	91.24
On-Peak Daily	$/MW-d	18.25
Off-Peak Daily	$/MW-d	13.00
On-Peak Hourly	$/MW-h	1.14
Off-Peak Hourly	$/MW-h	0.54
Network Service	$/MW-m	307.07

6.2.2 Energy Imbalance

Energy imbalance, explained in Section 4.2, 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.

In the development of a mechanism under which energy imbalance may be priced, it is important to note that Transmission Customers may choose to purchase power and energy from a number of different generation sources. It is also necessary to recognize that not all generators have predictable outputs that can be scheduled hours in advance.

Those who do are referred to as Dispatchable Generators. Non-dispatchable Generators, on the other hand, are energy sources which (by their nature) cannot be controlled on demand by the operator. These generators deliver energy directly to the grid as produced, without the use of energy storage technology. Examples include wind energy systems, photovoltaic solar systems, and run-of-river hydro systems.

The following describes NSPI's proposal for the supply of Energy Imbalance. The proposal is first described as it would apply to customers purchasing supply from Dispatchable Generators. It is then described as it would apply to customers purchasing supply from Non-Dispatchable Generators in Nova Scotia, i.e., those whose output is technically incapable of being dispatched or accurately scheduled.

6.2.2.1 Energy Imbalance for Customers of Dispatchable Generators

The difficulty of forecasting load, variations in generator output caused by factors such as component failures, 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 Dispatchable Generators, or customers with controllable loads have a substantial degree of control over the usage of the energy imbalance service, the use of pricing based on average embedded costs (as most of NSPI's current rates are) would provide an 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. Since 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.

For a bilateral schedule of a single load and its single generator, energy imbalance will be applied to the net of the generation and load imbalance.

We propose the following approach to load energy imbalance:

a) An hourly Deviation Band shall be defined to be $\pm$ 1.5 percent of the scheduled transaction (with a minimum Deviation Band of +/- 2 MW).

b) Hourly net deviations from scheduled transactions within the Deviation Band shall be returned in kind (i.e., deviations during peak periods are returned during the peak period, and deviations during off-peak periods are returned during the off-peak period) within the billing month.

c) Hourly (peak/non-peak) deviations within the Deviation Band that have not been corrected within the billing month will be settled at the average (peak/non-peak) marginal coat for the month.

d) Hourly deviations outside the deviation band are settled at 110% of the Transmission Provider's marginal cost when the customer is purchasing imbalance, and 90% of the Transmission Provider's marginal cost when the Transmission Provider is paying for over-supply.

We propose the following approach for generator energy imbalance for Dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110% of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90% of the hourly system marginal cost in the hour of the deviation.

6.2.2.2 Energy Imbalance for Non-Dispatchable Generators in Nova Scotia

Non-dispatchable Generators cannot control the output of their generation to take advantage of market prices. They have limited control over deviations from schedule, and no control over when deviations from schedule are repaid, i.e., they cannot "return in kind". Given these factors, NSPI proposes that for Non-dispatchable Generators in Nova Scotia supplying load in Nova Scotia, a deviation band of +/- 10 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will apply, within which, all net deviations from schedule will be settled using NSPI's hourly marginal cost in the hour of the deviation. Outside of this deviation band energy purchased from NSPI because of a shortfall in the expected schedule will be at 110% of the hourly marginal cost, and energy sold to NSPI because of overproduction relative to schedule will be at 90% of the hourly marginal cost.

FIGURE 6-5

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
COST DATA FOR PROXY UNITS

		Greenfield Combustion Turbine Unit	Combined Cycle Gas Unit
Capacity Rating	(kW)	183,000	122,000
	($000)	$96,336	$116,234
Capital Cost	($/kW)	$526	$953
Plant Life	(Years)	30	30
Variable O&M Costs	($/MWh)	$1.75	$1.41
	($000)	$2,172	$1,333
Fixed O&M Costs	($/kW-yr)	$11.87	$10.93
Year Dollars		2005	
Escalation Factor		2.00%	
Interest Rate (WACC)		8.30%	

NOTES:

1. The Combustion Turbine unit is used as a proxy for off-line services.
2. The Combined Cycle unit is used as a proxy for on-line services.
3. The Capital Costs of the Combined Cycle unit is currently being used by NSPI in its planning models. The cost has been updated to 2005$.
4. The Capital cost of the Combustion Turbine unit is the same as that used in the Generic Rate Design Hearing. The cost has been updated to 2005$.
5. The Fixed and Variable costs of the Combustion Turbine unit was based on an 80% capacity factor and segregated between fixed and variable based on the relationship of the Combined Cycle unit.
6. Fixed and Variable Costs include Corporate O/H assignment.

(Revised May 2005)

NOVA SCOTIA POWER INC.
COST OF CAPACITY BASED ANCILLARY SERVICES FROM PROXY UNITS

Ancillary Service	Proxy Source	(1) Capacity (MW)	(2) Capital Cost 2004$ ($/kW)	(3) Expected Life (yr)	(4) Escalating Capital Charge ($/kW-yr)	(5) Fixed O&M ($/kW-yr)	(6) Total Fixed Costs ($/kW-yr)	(7) Contribution Reactive Supply ($/kW-yr)	(8) Installed Capacity Credit ($/kW-yr)	(9) Energy Production Credit ($/kW-yr)	(10) Revenue Requirement Ancillary Serv. ($/kW-yr)
Regulation and Frequency Response:											
Regulation	Combined Cycle	122	$953	30	$78.79	$10.93	$89.72	$3.61	$0.00	$43.05	$43.05
Load Following	Combined Cycle	122	$953	30	$78.79	$10.93	$89.72	$3.61	$0.00	$43.05	$43.05
Operating Reserves:											
Spinning (10 minute)	Combined Cycle	122	$953	30	$78.79	$10.93	$89.72	$3.61	$0.00	$8.61	$77.49
Supplemental (10 Minute)	Combustion Turbine	183	$526	30	$43.54	$11.87	$55.41	$1.81	$0.00	$0.00	$53.60
Supplemental (30 Minute)	Combustion Turbine	183	$526	30	$43.54	$11.87	$55.41	$1.81	$0.00	$0.00	$53.60

NOTES:

1. The Escalating Capital charge includes Income Tax.
2. The Fixed O&M is the 2005 estimate from Figure 6-4.
3. The Contribution to Reactive Supply is $8.40/kVAR (Figure 6-9) multiplied by 88.8% (Figure 6-9 ratio of required MVAR to MVAR capability) multiplied by 48.4% (ratio of MVAR to MW at 90% power factor).
4. Capacity Factor for regulation 50%
5. Capacity Factor for load following 50%
6. Capacity Factor for spinning reserve 10%
7. Capacity factor for supplemental 10 minute reserve 0%
8. Capacity factor for supplemental 30 minute reserve 0%
9. Energy Production Credit is Total Fixed Costs in Col. 6 minus Col. 7 and minus Col. 8 multiplied by the appropriate Capacity Factor from Notes 4 to 8.

(Revised May 2005)

FIGURE 6-7

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
NOVA SCOTIA 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	2,145			2,145
Load Following	0	2,145			2,145
Operating Reserves (Contingency Reserves)					
Spinning (10 Minute)	0	2,145			2,145
Supplemental (10 Minute)	0	2,145			2,145
Supplemental (30 Minute)	0	2,145			2,145

NOTES:
1. The Network Billing Determinants (based on 12 NCP) are as per Figure 5-10.
2. These services apply only to Network Service loads or to point-to-point services within Nova Scotia. They do not apply to point-to-point service used for exports, because for exports, those services would be the responsibility of the customer receiving the supply. That customer would purchase these ancillary services from the transmission provider in the operating area where the load is located.

FIGURE 6-8

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
REVENUE REQUIREMENT AND RATE DESIGN

	(1) Revenue Requirement ($/kW-yr)	(2) Services Required (MW)	(3) Revenue Requirement ($000/yr)	(4) Usage (MW)	(5) Rate for Network ($/MW-yr)	(6) Rate for Network ($/MW-mo)	(7) Rate for Pt.-to-Pt. ($/MW-mo)	(8) Rate for Pt.-to-Pt. ($/MW-wk)	(9) Rate for Pt.-to-Pt. ($/MW-dy)
Regulation and Frequency Response									
Regulation	$43.05	26	$1,119.35	2,145	$521.84	$43.49	$43.49	$10.04	$1.43
Load Following	$43.05	142	$6,113.35	2,145	$2,850.05	$237.50	$237.50	$54.81	$7.81
Operating Reserves (Contingency Reserves)									
Spinning (10 Minute)	$77.49	25	$1,937.33	2,145	$903.18	$75.27	$75.27	$17.37	$2.47
Supplemental (10 Minute)	$53.60	100	$5,360.16	2,145	$2,498.91	$208.24	$208.24	$48.06	$6.85
Supplemental (30 Minute)	$53.60	50	$2,680.08	2,145	$1,249.45	$104.12	$104.12	$24.03	$3.42

NOTES:
1. Revenue Requirement is from Figure 6-5, Column 10.

(Revised May 2005)

FIGURE 6-9

NOVA SCOTIA POWER INC.
REACTIVE SUPPLY AND VOLTAGE CONTROL
CALCULATION OF REVENUE REQUIREMENT

Ancillary Service	Proxy Source	(1) Capacity (MVAR)	(2) Capital Cost ($000) 2005$	(3) Expected Life (yrs)	(4) Escalating Capital Charge ($000/yr)	(5) Fixed O&M ($000/yr)	(6) Total Fixed Costs ($000/yr)
Reactive Supply and Voltage Control							
	Static Var Compensators	200	$14,045.0	35	$1,153.56	$526.70	$1,680.26
Revenue Requirement per VAR of capability				$/kVAR/yr			$8.40
Estimated peak VAR requirement				MVAR	480		
Additional VAR requirement for dynamic system security				MVAR	480		
	Total VAR requirement			MVAR	960		960
Revenue requirement total				$000/yr			$8,065

NOTES:
1. Discount Rate 8.30%
2. Ecalation Rate 2.00%
3. The Escalating Capital charge includes Income Tax.
4. Total capability of generation currently on the system is 1,080.5 MVAR
5. The requirement divided by the capability is 960 MVAR divided by 1080.5 MVAR = 88.8%

(Revised May 2005)

FIGURE 6-10

NOVA SCOTIA POWER INC.
REACTIVE SUPPLY AND VOLTAGE CONTROL
RATE DESIGN

	(1) Revenue Requirement ($000/yr)	(2) Billing Determinants (MW)	(3) Yearly ($/MW-yr)	(4) Monthly ($/MW-mo)	(5) Weekly ($/MW-wk)	(6) On-Peak Daily ($/MW-dy)	(7) Off-Peak Daily ($/MW-dy)	(8) On-Peak Hourly ($/MW-hr)	(9) Off-Peak Hourly ($/MW-hr)
Reactive Supply and Voltage Control									
Total	$8,065.3								
Less: Credits	0.0								
Net	8,065.3								
Point-to-Point	$161.3	34	$4,744.27	$395.36	$91.24	$18.25	$13.00	$1.14	$0.54
Network Services	$7,904.0	2,145	$3,684.83	$307.07					
		2,179							

NOTES:
1. Point-to-Point and Network Services Reactive Supply and Voltage Control Revenue Requirements are segregated as per Figure 5-10, Col. 3.

7.0 Summary of Rates

Rates proposed for all OATT services included in this Application are set out in Figure 7-1. For ease of comparison, the rates for all services are provided in the common units of $/MW-month.

Figure 7-1

Rates for Services in NSPI's Open Access Transmission Tariff

Services	Schedule in OATT	$/MW-month
Scheduling, System Control, and Dispatch Service • Point-to-Point • Network	Schedule 1	 232.84 181.18
Reactive Supply and Voltage Control • Point-to-Point • Network	Schedule 2	 395.36 307.07
Regulation	Schedule 3	43.49
Load Following	Schedule 3	237.50
Energy Imbalance Service	Schedule 4	variable as described in OATT
Operating Reserve – Spinning	Schedule 5	75.27
Operating Reserve – Supplemental (10-minute)	Schedule 6	208.24
Operating Reserve – Supplemental (30-minute)	Schedule 6	104.12
Point-to-Point Service	Schedule 7	3,580.88
Network Integration Service	Schedule 10	2,782.20

SCHEDULE 1

Scheduling, System Control and Dispatch Service

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

Point-to-Point Transmission Service:

Delivery Period	Charge ($)
Yearly	One twelfth of $2,794.12/MW of Reserved Capacity per year
Monthly	$232.84/MW of Reserved Capacity per month
Weekly	$53.73/MW of Reserved Capacity per week
On-Peak Daily	$10.75/MW of Reserved Capacity per day
Off-Peak Daily	$7.66/MW of Reserved Capacity per day
On-Peak Hourly	$0.67/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.32/MW of Reserved Capacity per hour

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

<u>Network Integration Transmission Service:</u>

$181.18/MW of Network Integration Transmission Service per month.

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

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

<u>Point-to-Point Transmission Service:</u>

Delivery Period	Charge ($)
Yearly	One twelfth of $4,744.27/MW of Reserved Capacity per year
Monthly	$395.36/MW of Reserved Capacity per month
Weekly	$91.24/MW of Reserved Capacity per week
On-Peak Daily	$18.25/MW of Reserved Capacity per day
Off-Peak Daily	$13.00/MW of Reserved Capacity per day
On-Peak Hourly	$1.14/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.54/MW of Reserved Capacity per hour

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

<u>Network Integration Transmission Service:</u>

$307.07/MW of Network Integration Transmission Service per month.

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 the Transmission Provider (or the Operating Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The charges, payable monthly, for Regulation and Frequency Response Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Regulation (Point-to-Point Transmission Service):

The minimum period for which this service is available from the Transmission Provider is one day.

Delivery Period	**Charge ($)**
Yearly	One twelfth of $521.84/MW of Reserved Capacity per year
Monthly	$43.49/MW of Reserved Capacity per month
Weekly	$10.04/MW of Reserved Capacity per week
Daily	$1.43/MW of Reserved Capacity per day

Regulation (Network Integration Transmission Service):

$43.49/MW of Network Integration Transmission Service per month.

Load Following (Point-to-Point Transmission Service):

The minimum period for which this service is available from the Transmission Provider is one day.

Delivery Period	Charge ($)
Yearly	One twelfth of $2,850.05/MW of Reserved Capacity per year
Monthly	$237.50/MW of Reserved Capacity per month
Weekly	$54.81/MW of Reserved Capacity per week
Daily	$7.81/MW of Reserved Capacity per day

Load Following (Network Integration Transmission Service):

$237.50/MW of Network Integration Transmission Service per month.

Customer Obligations for Self-Supply and Third-Party Supply:

The customer obligation for self-supply or third-party supply of Regulation is equal to 1.4% of Reserved Capacity for Point-to-Point Transmission Service and 1.4% of the Network Load for Network Integration Transmission Service.

The customer obligation for self-supply or third-party supply of Load Following is equal to 8.0% of Reserved Capacity for Point-to-Point Transmission Service and 8.0% of Network Load for Network Integration Transmission Service.

SCHEDULE 4

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within an Operating Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

For a bilateral schedule of a single load and its single generator, this ancillary service will be applied to the net of the generation and load imbalance. Otherwise, this Ancillary Service will be applied separately to deviations from load schedules and deviations from generation schedules. This ancillary service does not apply to power exported from the Operating Area, which is covered by the Generation Balancing Service of the Standard Generator Interconnection and Operation Agreement.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;

- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;

- Support interconnected system frequency; or to

- Respond to transmission, generation or load contingencies.

For the purposes of Energy Imbalance Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Load Energy Imbalance Associated with Point-to-Point or Network Integration Transmission Service:

For each Transmission Customer taking service under Part II or Part III of this Tariff, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

A deviation band of +/- 1.5 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be applied hourly to any net load energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

Parties should attempt to eliminate energy imbalances within the limits of the deviation band within the billing month in accordance to the following:

- For hourly imbalances that arise during peak hours, such imbalances should be eliminated via deliveries or withdrawals during peak hours; and

- For hourly imbalances that arise during non-peak hours, such imbalances should be eliminated via deliveries or withdrawals during non-peak hours.

Net load energy imbalances within the deviation band that have not been eliminated at the end of the billing month will be subject to the charges set below:

- Energy supplied by the Transmission Provider during peak hours to compensate for a net shortfall in peak hours delivery over the billing month will be charged at the average on-peak system marginal cost for the billing month. Energy supplied by the Transmission Provider during non-peak hours to compensate for a net shortfall in non-peak hours delivery over the billing month will be charged at the average non-peak system marginal cost for the billing month.

- Energy supplied to the Transmission Provider during peak hours as a net excess of the peak hours delivery over the billing month will be purchased by the Transmission Provider at the average on-peak system marginal cost for the billing month. Energy supplied to the Transmission Provider during non-peak hours as a net excess of the non-peak hours delivery over the billing month will be purchased by the Transmission Provider at the average non-peak system marginal cost for the billing month.

Energy imbalances outside of the deviation band are not eligible for elimination and are subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net hourly shortfall in delivery will be charged at 110% of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90% of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Dispatchable Generators:

For Dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110% of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90% of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Non-Dispatchable Generators:

For Non-dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

Energy Imbalances inside a deviation band of +/- 10% of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at the hourly system marginal cost in the hour of the deviation.

All deviations from schedule outside of the +/- 10% deviation band will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110% of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90% of the hourly system marginal cost in the hour of the deviation.

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The charges, payable monthly, for Spinning Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

<u>Point-to-Point Transmission Service:</u>

The minimum period for which this service is available from the Transmission Provider is one day.

Delivery Period	Charge ($)
Yearly	One twelfth of $903.18/MW of Reserved Capacity per year
Monthly	$75.27/MW of Reserved Capacity per month
Weekly	$17.37/MW of Reserved Capacity per week
Daily	$2.47/MW of Reserved Capacity per day

<u>Network Integration Transmission Service:</u>

$75.27/MW of the Network Integration Transmission Service per month.

Customer Obligations for Self-supply and Third-party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve – Spinning Reserve is equal to 1.40% of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service and 1.40% of the Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers. This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Operating Reserve service will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

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 interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The charges, payable monthly, for Supplemental Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Operating Reserve – Supplemental (10 minute):

Point-to-Point Transmission Service:

The minimum period for which this service is available from the Transmission Provider is one day.

Delivery Period	Charge ($)
Yearly	One twelfth of $2,498.91/MW of Reserved Capacity per year
Monthly	$208.24/MW of Reserved Capacity per month
Weekly	$48.06/MW of Reserved Capacity per week
Daily	$6.85/MW of Reserved Capacity per day

Network Integration Transmission Service:

$208.24/MW of the Network Integration Transmission Service per month.

Customer Obligations for Self-supply and Third-Party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve – Supplemental Reserve will be equal to 5.6% of Reserved Capacity for Point-to-Point Transmission Service and 5.6% of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

Operating Reserve – Supplemental (30 minute):

Point-to-Point Transmission Service:

The minimum period for which this service is available from the Transmission Provider is one day.

Delivery Period	Charge ($)
Yearly	One twelfth of $1,249.45/MW of Reserved Capacity per year
Monthly	$104.12/MW of Reserved Capacity per month
Weekly	$24.03/MW of Reserved Capacity per week
Daily	$3.42/MW of Reserved Capacity per day

Network Integration Transmission Service:

$104.12/MW of the Network Integration Transmission Service per month.

Customer Obligations

The customer obligation for reserves is equal to 2.8% of Reserved Capacity for Point-to-Point Transmission Service and 2.8% of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110% of the stated MW amount within 30 minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for at least 60 minutes from the time of activation.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

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 $42,970.59/MW of Reserved Capacity per year.

2) **Monthly delivery**: $3,580.88/MW of Reserved Capacity per month.

3) **Weekly delivery**: $826.36/MW of Reserved Capacity per week.

4) **On-Peak Daily delivery**: $165.27/MW of Reserved Capacity per day.

5) **Off-Peak Daily Delivery:** $117.73/MW of Reserved Capacity per day

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section (3) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

6) **Discounts**: Three principal requirements apply to discounts for transmission service as follows:

(i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

(ii) any customer-initiated requests for discounts (including requests for use by one's Wholesale Merchant or an affiliate's use) must occur solely by posting on the OASIS, and

(iii) once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

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

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

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

1) **Monthly delivery**: $3,580.88/MW of Reserved Capacity per month.

2) **Weekly delivery**: $826.36/MW of Reserved Capacity per week.

3) **On-Peak Daily delivery**: $165.27/MW of Reserved Capacity per day.

4) **Off-Peak Daily Delivery:** $117.73/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 megawatts of Reserved Capacity in any day during such week.

5) **On-Peak Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $10.33/MWh.

6) **Off-Peak Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $4.91/MWh.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in Section (3) above times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in Section (2) above times the highest amount in megawatts of Reserved Capacity in any hour during such week.

7) **Discounts**: Three principal requirements apply to discounts for transmission service as follows:

(i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

(ii) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and

(iii) once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

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

9) 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 9

Real Power Loss Factors

For Point-to-Point service, the Transmission Provider will seasonally calculate loss factors to be used on a path-by-path basis. For each season, winter and summer, the power flow models used to calculate the losses will include peak and off-peak hours to derive an average loss factor for each path. For long-term Point-to-Point service, the annual loss factor to be used for a particular path is the average of the seasonal values. The loss factors will be posted on the Transmission Provider's OASIS site.

For Network Service, the Transmission Provider will apply the system average loss factor of 3.15%. This factor will be reviewed annually and is subject to change annually. It will be posted on the OASIS.

Transmission Customers are required to provide the losses associated with their service. All Transmission Customers are required to include an amount of additional capacity in their service requests sufficient to carry the losses associated with their service.

Locational Loss Factors for new generation will be determined during the System Impact Study and be applied to generation dispatch merit order if such generation is to be economically dispatched by the Transmission Provider. If the generator is self-dispatched, loss factors will be applied to determine the unit net output.

Locational Loss Factors for each generator will be determined on an annual basis and will be posted on the OASIS.

SCHEDULE 10

Network Integration Transmission Service Rate

Energy Imbalance Service does not apply to deviations in scheduled delivery of energy from Non-dispatchable Generation sources to Network Load inside the Transmission Provider's Operating Area.

1. The rate charged for Network Integration Transmission Service is $2,782.20/MW-m, based on the Transmission Customer's Net Non-coincident Monthly Peak Demand.

2. Net Non-coincident Monthly Peak Demand is the maximum hourly demand at each Point of Delivery designated as Network Load (including its designated Network Load not physically interconnected to the Transmission Provider's Transmission System).

3. Transmission congestion charges will be applied as follows:

$$A = B \times (C/D)$$

Where

A = the Network Customer's congestion charge for all hours of the month that congestion redispatch costs occurred.

B = Total redispatch costs during the month.

C = The Network Customer's load during the hours for which redispatch costs were incurred.

D = The sum of all Network Integration Transmission Service load (including load served by the Transmission Provider) and Point-to-Point Transmission Service scheduled serving load in the

Operating area during the hours of the month for which redispatch costs were incurred.

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Exhibit 2

STANDARD GENERATOR INTERCONNECTION PROCEDURES (GIP)

(Applicable to Generating Facilities Connected to the Transmission System – 69kV and above)

Note: Only revised pages of this Exhibit are being submitted. Other pages remain as filed May 12, 2004

Revised May 2005

SECTION 2. SCOPE AND APPLICATION

2.1 Application of Standard Generator Interconnection Procedures (GIP)

Sections 2 through 13 apply to processing an Interconnection Request pertaining to a Generating Facility.

2.2 Comparability

The Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this GIP. The Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

2.3 Base Case Data

Transmission Provider shall provide base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list upon request subject to confidentiality provisions. Such databases and lists, hereinafter referred to as Base Cases, shall include all (i) generation projects and (ii) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service

Nothing in this GIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

2.5 Expedited Process for Small Generating Facilities

In assessing whether the interconnection process can be expedited, the Transmission Provider will consider the capacity of the Generation Facility, the Point of Interconnection requested, and the results of any previously completed System Impact Studies that may be relevant.

If the process is expedited, the Transmission Provider will:

- *Forego the Feasibility Study*
- *Combine the System Impact Study and the Facilities Study*
- *Eliminate the requirement for coordination with Affected Systems*
- *Modify the System Impact Study scope to exclude stability analysis.*

ARTICLE 11. PERFORMANCE OBLIGATION

11.1 Interconnection Customer Interconnection Facilities

Interconnection Customer shall design, procure, construct, install, own and operate the Interconnection Customer Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 Transmission Provider's Interconnection Facilities

Transmission Provider or Transmission Owner shall design, procure, construct, install, own and operate the Transmission Provider's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades

Transmission Provider or Transmission Owner shall design, procure, construct, install, own and operate the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless the Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall be solely funded by the Interconnection Customer.

11.4 Transmission Credits

11.4.1 Refund of Amounts Advanced for Network Upgrades

Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Generating Facility. Any repayment shall include interest from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date:

(1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or

(2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides return of all amounts advanced for Network Upgrades not previously repaid; however full reimbursement shall not extend beyond (20) years from the Commercial Operation Date

If the Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and

Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades.

Before such re-imbursement can occur, the Interconnection customer, or the entity that ultimately constructs the generating facility, if different, is responsible for identifying the entity to which reimbursement must be made.

Exhibit 3

DEVELOPMENT OF NSPI'S TRANSMISSION REVENUE REQUIREMENT

Revised May 2005

1. Overview

The transmission revenue requirement used in the development of the OATT rates includes:

a) Depreciation
b) Interest
c) Return
d) All taxes (income, grants in lieu, large corporation tax, etc.)
e) Operating & Maintenance
f) Appropriate portions of corporate overheads

Each of these is discussed in more detail below. Items a – d above are derived from the total transmission assets.

2. Total Transmission Assets

NSPI's average transmission assets in 2005 have a gross plant value (i.e. before any depreciation) of $679.3 million, as shown in Figure 5-9. This includes $573.5 million of transmission assets plus $44.0 million of General Property assets, plus $61.8 million of other assets such as deferred charges, materials inventory and net receivables which are assigned to the transmission function in the Cost of Service Study ("COSS").

Consistent with the EMGC recommendations, the following adjustments are made for the purpose of developing the OATT revenue requirement:

- Generator step-up transformers have been excluded ($17.6 million)
- Transmission lines that are radial-to-generation have been excluded ($17.5 million)

- Portions of substations (such as breakers) that are radial-to-generation have been excluded ($7.4 million)

With these adjustments, NSPI's total transmission assets for the purposes of OATT are $636.8 million.

3. Depreciation

The depreciation rates approved by the Board in November, 2003 (Decision NSUARB – NSPI – P – 879) were applied to the transmission assets and general property assets to develop a total depreciation charge. The composite rates being used for 2005 are:

Transmission Assets	2.58%
General Property	6.22%

These rates exclude salvage values, which for transmission assets total $0.6 million and includes tax effects associated with estimated Undepreciated Capital Cost balance.

The total value of average depreciable transmission assets is $560.9 million ($679.3 million minus $61.8 million for deferred charges, materials inventory and net receivables, minus $44.0 million for General Property, minus $12.6 million for non-depreciable land). The depreciation charge for OATT is calculated as follows:

(Transmission Assets x Transmission Depreciation Rates) + (General Property Assets x General Property Depreciation Rates) + Salvage + Tax Effects

= $560.9 million x 0.0258 + $44.0 x 0.0622 + 0.6 + (0.6) = $17.2 million

With portions of this excluded (associated with generator step-up transformers, etc.), the net charge for the purpose of OATT is $16.1 million.

4. **Interest, Return and Taxes**

The Weighted Average Cost of Capital (“WACC”), adjusted to reflect taxes, is 12.22% as shown in Table E3-1. This reflects the forecasted capital structure and Return on Equity (“ROE”), 37.5% and 9.55%, respectively for 2005. In addition, the interest charges include the amortization of defeasance.

Applying this WACC to the net book value of the total transmission, associated general property assets and associated deferred charges, working capital and receivables, the total charge for interest, return and taxes is $46.6 million.

With this approach, the ROE and the capital structure are inputs to the process.

5. **Operating and Maintenance (“O&M”)**

For 2005, O&M charges total $19.0 million. They include all transmission-related O&M associated with the following departments:

a) Transmission Operations and Maintenance
b) Transmission and Distribution Asset Management
c) Control Centre Operations

6. **Corporate Overheads**

These costs include corporate functions such as the Executive, Finance, IT, Regulatory Affairs, Legal, Procurement, etc. Based on estimates prepared by NSPI, the costs of each group are assigned to the Power Production, Customer Operations and Marketing and Sales. The portion assigned to Customer Operations is split between Transmission and Distribution, and the Transmission portion ($6.5 million) is included in OATT.

TABLE E3-1

Nova Scotia Power Inc.
2005 Transmission Tariff WACC Rate
Millions of dollars

1) Interest (Carrying Cost)

a) Weighted Average Cost of Capital - Pretax

	Proportion	Cost	Extended	
ST Debt	8.3%	4.60%	0.38%	
LT Debt	45.0%	8.54%	3.84%	
Preferred	9.2%	5.42%	0.50%	
Common	37.5%	9.55%	3.58%	
	100.0%		8.30%	
WACC - pretax cost				8.30%

b) Additional income tax for common equity

Extended equity cost		3.58%	
Effective tax rate (excluding surtax)		37.0%	
Income tax		2.10%	
WACC - equity tax cost			2.10%

c) Large Corporations Tax

Provincial capital tax	0.300%	
Federal capital tax	0.225%	
Ave. NPV - Transmission	$299.871	
Ave. NPV - assigned GP	26.100	
Ave. Deferred Chgs & W/C	54.995	
NPV - Total Transmission	$380.967	
Provincial capital tax	$1.14	
Federal capital tax	$1.36	
Total	$2.50	
Percentage of NBV	0.66%	
WACC - Large Corporations Taxes		0.66%

d) Grants in Lieu of Property Tax

Total 2005 Forecasted Expense	$31.857	
Transmission % of Total Plant	13.8%	
Transmission Allocated Amount	$4.4	
Percentage of NBV	1.16%	
WACC - Grants in Lieu of Property Tax		1.16%

Total WACC - Interest / Carrying Cost	**12.22%**

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Exhibit 4

EMBEDDED COST OF ANCILLARY SERVICES

Revised May 2005

Introduction

NSPI is recommending that the charges for Ancillary Services be calculated on the basis of embedded costs, in accordance with the consensus proposal. This exhibit calculates these charges based on the embedded costs of existing units that currently supply those services.

Methodology

The approach used to calculate the cost is described below.

This approach is similar to the approach used by NB Power to develop Ancillary Service charges based on embedded costs, for comparison to the charges it was proposing based on proxy units. Following the NB Power methodology, the costs of providing each Ancillary Service are derived from the fixed costs of each unit that is expected to provide such service. The derivation of charges for each service is described in the following Tables:

Table E4-1: Generating Unit Specific Fixed Charge Summary

This table details the total fixed costs of each of the generating units. OM&G, depreciation, interest, return on equity and taxes are shown for each generating unit and then divided by the respective net book value to produce the respective fixed charge rate. The net book value and the fixed charge rates are used in subsequent schedules.

Table E4-2: Voltage Control and Reactive Supply

This table details the cost of providing "Voltage Control and Reactive Supply" service to the NSPI Transmission System from NSPI's generating units. This table:

a) Calculates the % of generator (i.e., the actual generator, not the whole generating station) and exciter (the auxiliary device needed to develop and control voltage and reactive power, without which a synchronous generator cannot produce power) capital costs used to supply VARs.

b) Applies fixed charge rates to the generator and exciter capital costs to calculate annual fixed costs.

c) Calculates annual energy consumption costs to operate the exciter.

d) Sums generator capital, exciter capital and exciter energy consumption costs.

e) Allocates a portion of this total to the provision of the service based on the ratio of the total reactive requirement to the total reactive capability.

Table E4-3: Regulation

This table details the cost of providing Regulation Service. This service is provided by generating units that are equipped with Automatic Generation Control (AGC) equipment which allows these units to respond to changes in load that occur minute to minute. This schedule calculates the ability to provide the service based on the time that each generating unit was called upon to provide AGC, the regulating capacity of each generating unit, and the ramp rate of each generating unit. The calculated ability of each unit is used to produce a percentage participation for each unit. The participation percentages were then multiplied by the respective net book values and fixed charge rates to produce annual costs weighted by the ability of each unit to provide the service. The sum of the weighted costs produces a total weighted annual cost per kW of service.

Table E4-4: Load Following

This table details the cost of providing Load Following Service that represents the requirement of generation output to follow load from hour to hour. The expected provision of the service by each unit was used to produce a percentage participation for each unit. The participation percentages were then multiplied by the respective net book values and fixed charge rates to produce annual costs weighted by the ability of each unit to provide the service. The sum of the weighted costs produces a total weighted annual cost per kW of service.

Table E4-5: Spinning Reserve Cost

This table details the cost of Spinning Reserve. This service is provided by generating units that have the ability to adjust their contribution to NSPI's net generation in response to commands from the system operator. These units must be running and synchronized to the Transmission System. This is a service that must respond within 10 minutes of a contingency (such as the loss of a generator because of a forced outage). The methodology evaluates the ability of each unit to respond to commands from the system operator.

There are two ways in which a generator may be able to respond to such a command from the system operator. In the first instance the net output of the generator can be increased within ten minutes. The calculation of the ability to respond considers the capacity factor, operating limits, and the ramp rate of each unit. In the second instance, the system operator can, within ten minutes, curtail a recallable export of energy from that generator to replace lost generation in Nova Scotia.

The calculated ability of each unit was used to produce a percentage contribution for each unit. The contribution percentages were then multiplied by the respective net book values and fixed charge rates to produce annual costs weighted by the ability of each unit to provide the service. The sum of the weighted costs produces a total weighted annual cost per kW of service.

Table E4-6: 10 Minute Reserve Cost

This table details the cost of "Supplemental 10 Minutes Reserve Service". This service is provided by generating units that have the ability to adjust their contribution to NSPI's net generation in response to commands from the system operator. These units are not required to be running and synchronized to the Transmission System. This is also a service that must respond within 10 minutes of a contingency. The methodology evaluates the ability of each unit to respond to commands from the system operator.

There are two ways in which a generator may be able to respond to such a command from the system operator. In the first instance the net output of the generator can be increased within ten minutes. The calculation of the ability to respond considers the capacity factor, operating limits, and the ramp rate of each unit. In the second instance, the system operator can, within ten minutes, curtail a recallable export of energy from that generator to replace lost generation in Nova Scotia.

The calculation of the weighted annual cost for the provision of this service is similar to the calculation of the cost for "Operating Reserve – Spinning Service".

The calculated ability of each unit was used to produce a percentage contribution for each unit. The contribution percentages were then multiplied by the respective net book values and fixed charge rates to produce annual costs weighted by the ability of each unit to provide the service. The sum of the weighted costs produces a total weighted annual cost per kW of service.

Table E2-7: 30 Minutes Reserve Cost

This table details the cost of "Supplemental 30 Minute Operating Reserve Service". This service is provided by generating units that have the ability to adjust their contribution to NSPI's net generation in response to commands from the system operator. These units are not required to be running and synchronized to the Transmission System. This is a service that must respond within 30 minutes of a contingency. The methodology evaluates the ability of each unit to respond to commands from the system operator.

There are two ways in which a generator may be able to respond to such a command from the system operator. In the first instance the net output of the generator can be increased. The calculation of the ability to respond considers the capacity factor, operating limits, and the ramp rates of each unit. In the second instance the system operator can curtail a recallable export of energy from that generator to replace lost generation in Nova Scotia.

The calculation of the weighted annual cost for the provision of this service is similar to the calculation of the cost of "Spinning Reserve" and "Supplemental 10 Minute Operating Reserve Service".

The calculated ability of each unit was used to produce a percentage contribution for each unit. The contribution percentages were then multiplied by the respective net book values and fixed charge rates to produce annual costs weighted by the ability of each unit to provide the service. The sum of the weighted costs produces a total weighted annual cost per kW of service.

Table E4-8: Comparison with Proxy Costs

Table E2-8 compares the costs of providing the services from the generating facilities that are expected to actually provide the service with those based on the proxy method.

As shown in this table, the cost of providing Ancillary Services using this Embedded Cost Study approach is higher than that determined by the Proxy Method.

NSPI **Embedded Cost of Ancillary Services**

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
GENERATING STATION UNIT SPECIFIC FIXED CHARGE RATE SUMMARY

	Lingan	Tufts Cove	Trenton	Pt. Tupper	Pt. Aconi	Sub-Total Thermal Gen.	Wreck Cove	Annapolis Tidal Power	Other Hydro	Wind Generation	Total Hydro
Generator Nameplate Capacity kW's	600000	350000	310000	150000	185000	1595000	200000	17200	163000	1300	381500
Gross Plant Cost	$451,829,560	$154,448,551	$308,031,167	$142,022,315	$487,395,932	$1,543,727,524	$162,200,373	$32,766,338	$162,186,696	$1,991,516	$359,144,923
Gross Plant Cost/kW	$753.05	$441.28	$993.65	$946.82	$2,634.57	$967.85	$811.00	$1,905.02	$995.01	$1,531.94	$941.40
Net Plant Value	$242,695,201	$85,084,729	$216,894,052	$80,271,520	$382,431,806	$1,007,377,307	$100,249,779	$23,617,220	$114,864,771	$1,756,986	$240,488,756
Net Plant Value/kW	$404.49	$243.10	$699.66	$535.14	$2,067.20	$631.58	$501.25	$1,373.09	$704.69	$1,351.53	$630.38
- share of General Property Plant	$18,980,863	$6,654,361	$16,962,990	$6,277,927	$29,909,473	$78,785,614	$7,840,399	$1,847,071	$8,983,418	$137,411	$18,808,300
- share of Deferred Chgs & W/C	$44,361,413	$15,552,342	$39,645,311	$14,672,552	$69,903,382	$184,135,001	$18,324,309	$4,316,910	$20,995,733	$321,153	$43,958,105
Total NPV incl. GP & Deferred Chgs.	$306,037,476	$107,291,433	$273,502,353	$101,221,999	$482,244,661	$1,270,297,921	$126,414,487	$29,781,200	$144,843,922	$2,215,551	$303,255,160
OM&G (Direct)	$19,973,900	$12,436,400	$14,729,600	$8,343,600	$8,272,600	$63,756,100	$1,032,600	$455,900	$6,133,000	$52,700	$7,674,200
OM&G (Overhead)	$1,656,777	$1,031,564	$1,221,778	$692,078	$686,188	$5,288,385	$85,651	$37,816	$508,715	$4,371	$636,553
Grants in Lieu	$3,397,900	$1,191,245	$3,036,666	$1,123,857	$5,354,309	$14,103,977	$1,403,566	$330,657	$1,608,186	$24,599	$3,367,008
Depreciation (Direct)	$9,714,336	$3,969,328	$7,669,976	$3,465,344	$11,941,200	$36,760,184	$1,930,184	$563,581	$2,196,012	$62,235	$4,752,012
Depr. (Gen.Prop. & GB Write-off)	$2,974,754	$1,215,500	$2,348,724	$1,061,168	$3,656,671	$11,256,816	$591,067	$172,582	$672,470	$19,058	$1,455,176
Interest	$11,910,198	$4,175,509	$10,644,014	$3,939,302	$18,767,732	$49,436,754	$4,919,729	$1,159,008	$5,636,956	$86,224	$11,801,917
Preferred Dividends	$1,526,405	$535,131	$1,364,131	$504,859	$2,405,263	$6,335,789	$630,510	$148,538	$722,429	$11,050	$1,512,528
Corporate Taxes	$7,937,085	$2,782,605	$7,093,287	$2,625,194	$12,507,021	$32,945,191	$3,278,561	$772,376	$3,756,529	$57,460	$7,864,926
Return	$10,581,196	$3,709,584	$9,456,300	$3,499,734	$16,673,532	$43,920,346	$4,370,761	$1,029,680	$5,007,955	$76,602	$10,484,998
TOTAL	$69,672,551	$31,046,864	$57,564,475	$25,255,136	$80,264,516	$263,803,542	$18,242,630	$4,670,138	$26,242,251	$394,300	$49,549,318
OM&G	7.07%	12.55%	5.83%	8.93%	1.86%	5.44%	0.88%	1.66%	4.59%	2.58%	2.74%
Depreciation	4.15%	4.83%	3.66%	4.47%	3.23%	3.78%	1.99%	2.47%	1.98%	3.67%	2.05%
Sub-Total	11.21%	17.39%	9.50%	13.40%	5.09%	9.22%	2.88%	4.13%	6.57%	6.25%	4.79%
Grants in Lieu	1.11%	1.11%	1.11%	1.11%	1.11%	1.11%	1.11%	1.11%	1.11%	1.11%	1.11%
Interest	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%
Preferred Dividends	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Corporate Taxes	2.59%	2.59%	2.59%	2.59%	2.59%	2.59%	2.59%	2.59%	2.59%	2.59%	2.59%
Return	3.46%	3.46%	3.46%	3.46%	3.46%	3.46%	3.46%	3.46%	3.46%	3.46%	3.46%
Cost of Capital	11.55%	11.55%	11.55%	11.55%	11.55%	11.55%	11.55%	11.55%	11.55%	11.55%	11.55%
FIXED CHARGE RATE	**22.77%**	**28.94%**	**21.05%**	**24.95%**	**16.64%**	**20.77%**	**14.43%**	**15.68%**	**18.12%**	**17.80%**	**16.34%**

NOTES:

1. **The Gross and Net Asset Values have been averaged based on actual year-end balances for 2003 and 2004.**
2. **Tufts Cove #5 was in-service at the end of 2004, therefore average GPV & NPV would account for only 50% of asset value at the end of 2004.**
3. **OM&G and Capital Related Expenses have been based on the 2005 Compliance Filing in response to UARB's Decision on the 2005 Rate Application.**
4. **The percentages are calculated on "Total NPV incl. GP and Deferred Charges" since the capital-related expenses such as interest, taxes and return reflect NSPI's total capitalization.**

TABLE E4-1
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NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
GENERATING STATION UNIT SPECIFIC FIXED CHARGE RATE SUMMARY

	Burnside	Victoria Junction	Tusket	Tufts Cove 4	Tufts Cove 5	Total Combustion Turbines	Total Generation
Installed Capacity kW's	120000	60000	24000	54000	54000	312000	2288500
Gross Plant Cost	$18,764,579	$7,352,598	$4,368,960	$42,739,289	$15,629,500	$88,854,926	$2,007,356,872
Gross Plant Cost/kW	$156.37	$122.54	$182.04	$791.47	$289.44	$284.79	$877.15
Net Book Value	$5,834,692	$1,293,328	$1,833,557	$39,705,088	$15,629,500	$64,296,165	$1,327,791,727
Net Book Value/kW	$48.62	$21.56	$76.40	$735.28	$289.44	$206.08	$580.20
- share of General Property Plant	456,323	101,149	143,400	3,105,281	1,222,362	$5,028,516	$103,844,791
- share of Deferred Chgs & W/C	1,066,503	236,403	335,150	7,257,555	2,856,862	$11,752,473	$242,702,440
Total NPV incl. GP & Deferred Chgs.	$7,357,518	$1,630,880	$2,312,107	$50,067,924	$19,708,724	$61,368,429	$1,674,338,958
OM&G (Direct)	$557,500	$160,500	$134,700	$118,350	$118,350	$1,089,400	$72,519,700
OM&G (Overhead)	$46,243	$13,313	$11,173	$9,817	$9,817	$90,363	$6,015,300
Grants in Lieu	$81,690	$18,107	$25,671	$555,899	$218,824	$900,191	$18,590,000
Depreciation (Direct)	$403,438	$145,581	$114,030	$1,423,218	$520,462	$2,606,730	$44,639,389
Depr. (Gen.Prop. & GB Write-off)	$123,542	$44,580	$34,919	$435,822	$159,378	$798,241	$13,669,611
Interest	$286,336	$63,470	$89,981	$1,948,516	$767,013	$3,155,316	$65,161,000
Preferred Dividends	$36,697	$8,134	$11,532	$249,721	$98,300	$404,384	$8,351,000
Corporate Taxes	$190,817	$42,297	$59,965	$1,298,512	$511,146	$2,102,737	$43,424,000
Return	$254,385	$56,387	$79,941	$1,731,090	$681,426	$2,803,230	$57,890,000
TOTAL	$1,980,648	$552,371	$561,911	$7,770,945	$3,084,716	$13,950,591	$330,260,000
OM&G	8.21%	10.66%	6.31%	0.26%	0.65%	1.92%	4.69%
Depreciation	7.16%	11.66%	6.44%	3.71%	3.45%	5.55%	3.48%
Sub-Total	15.37%	22.32%	12.75%	3.97%	4.10%	7.47%	8.17%
Grants in Lieu	1.11%	1.11%	1.11%	1.11%	1.11%	1.47%	1.11%
Interest	3.89%	3.89%	3.89%	3.89%	3.89%	5.14%	3.89%
Preferred Dividends	0.50%	0.50%	0.50%	0.50%	0.50%	0.66%	0.50%
Corporate Taxes	2.59%	2.59%	2.59%	2.59%	2.59%	3.43%	2.59%
Return	3.46%	3.46%	3.46%	3.46%	3.46%	4.57%	3.46%
Cost of Capital	11.55%	11.55%	11.55%	11.55%	11.55%	15.26%	11.55%
FIXED CHARGE RATE	**26.92%**	**33.87%**	**24.30%**	**15.52%**	**15.65%**	**22.73%**	**19.72%**

NOTES:

1. The Gross and Net Asset Values have been averaged based on actual year-end balances for 2003 and 2004.
2. Tufts Cove #5 was in-service at the end of 2004, therefore average GPV & NPV would account for only 50% of asset value at the end of 2004.
3. OM&G and Capital Related Expenses have been based on the 2005 Compliance Filing in response to UARB's Decision on the 2005 Rate Application.
4. The percentages are calculated on "Total NPV incl. GP and Deferred Charges" since the capital-related expenses such as interest, taxes and return reflect NSPI's total capitalization.

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TABLE E4-2
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NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
VOLTAGE CONTROL and REACTIVE SUPPORT SERVICES REVENUE REQUIREMENT

Unit	Generator Nameplate Rating					Generator Net Book Value $	Fixed Charge Rate	MVAR Production at System Peak	Allocation to Reactive Power	Allocated Generator Cost $	Exciter Cost Ratio	Exciter Cost $	Total Gen/Exciter Allocation $
	MVA	MW	MVAR	Peak MW	PRACTICAL MVAR								
Column	1	2	3	4	5	6	7	8	9	10	11	12	13
Formula			**(Note 2)**	**(Note 3)**	= sqrt((1*1) - (4*4))				= (3*3)/(1*1)	= 6*9		= 6*11	= 7*(10+12)
Lingan 1	177.0	150.0	94.0	163.0	69.0	$2,947,081	22.77%	36.0	28.18%	$830,533	8%	$235,766	$242,754
Lingan 2	177.0	150.0	94.0	163.0	69.0	$2,947,081	22.77%	26.0	28.18%	$830,533	8%	$235,766	$242,754
Lingan 3	177.0	150.0	94.0	163.0	69.0	$4,333,775	22.77%	22.0	28.18%	$1,221,325	8%	$346,702	$356,977
Lingan 4	177.0	150.0	94.0	163.0	69.0	$4,333,775	22.77%	24.0	28.18%	$1,221,325	8%	$346,702	$356,977
Tufts Cove 1	117.0	100.0	60.7	82.5	83.0	$1,151,973	28.94%	37.0	26.95%	$310,441	10%	$115,197	$123,167
Tufts Cove 2	117.0	100.0	60.7	103.0	55.5	$1,662,892	28.94%	41.0	26.95%	$448,127	8%	$133,031	$168,169
Tufts Cove 3	177.0	150.0	94.0	156.0	69.0	$2,290,218	28.94%	46.0	28.18%	$645,419	8%	$183,217	$239,782
Tufts Cove 4	60.0	54.0	26.2	51.0	31.6	$7,941,018	15.52%	5.0	19.00%	$1,508,793	8%	$635,281	$332,778
Tufts Cove 5	60.0	54.0	26.2	51.0	31.6	$3,125,900	15.65%	5.0	19.00%	$593,921	8%	$250,072	$132,098
Trenton 5	177.0	150.0	94.0	153.0	81.7	$1,649,798	21.05%	33.0	28.18%	$464,939	10%	$164,980	$132,580
Trenton 6	188.0	160.0	98.7	168.0	84.4	$11,297,230	21.05%	46.0	27.57%	$3,114,537	8%	$903,778	$845,741
Pt. Tupper 2	177.0	150.0	94.0	161.0	69.0	$4,729,216	24.95%	38.0	28.18%	$1,332,767	8%	$378,337	$426,925
Pt. Aconi 1	218.0	185.0	115.3	188.0	110.4	$13,385,113	16.64%	45.0	27.98%	$3,745,657	8%	$1,070,809	$801,650
Wreck Cove 1	111.0	100.0	48.2	83.0	20.0	$1,253,122	14.43%	2.0	18.84%	$236,060	8%	$100,250	$48,532
Wreck Cove 2	111.0	100.0	48.2	83.0	20.0	$1,253,122	14.43%	2.0	18.84%	$236,060	8%	$100,250	$48,532
Annapolis Tidal	19.1	17.2	8.3	19.0	2.0	$1,180,861	15.68%	0.0	18.91%	$223,250	8%	$94,469	$49,823
Wind (Note 1)	1.0	1.3	0.0	1.0	0.0								
Other Hydro	181.0	163.0	78.7	163.0	78.7	$0	18.12%	10.0	18.90%	$0	8%	$0	$0
Burnside 1	35.0	30.0	18.0	31.0	16.2	$291,735	26.92%	10.0	26.53%	$77,399	8%	$23,339	$27,119
Burnside 2	35.0	30.0	18.0	31.0	16.2	$291,735	26.92%	10.0	26.53%	$77,399	8%	$23,339	$27,119
Burnside 3	35.0	30.0	18.0	31.0	16.2	$291,735	26.92%	10.0	26.53%	$77,399	8%	$23,339	$27,119
Burnside 4	35.0	30.0	18.0	31.0	16.2	$291,735	26.92%	15.0	26.53%	$77,399	8%	$23,339	$27,119
Victoria Junction 1	35.0	30.0	18.0	34.0	8.3	$129,333	33.87%	8.0	26.53%	$34,313	8%	$10,347	$15,126
Victoria Junction 2	35.0	30.0	18.0	33.0	11.7	$129,333	33.87%	7.0	26.53%	$34,313	8%	$10,347	$15,126
Tusket 1	28.0	24.0	14.4	24.0	14.4	$366,711	24.30%	7.0	26.53%	$97,291	8%	$29,337	$30,774
TOTALS	2,660.1	2,288.5	1,351.5	2,329.5	1,112.1	$67,274,491		485.0					$4,718,741

NOTES:

1. The Wind Turbine Induction Generators have no VAR Capability.
2. Nameplate based on MVA and rated Power Factor.
3. Gross generator output on peak.
4. Value of increased generator capacity required to operate excitor.

TABLE E4-2
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NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
VOLTAGE CONTROL and REACTIVE SUPPORT SERVICES REVENUE REQUIREMENT

Unit	Unit Exciter Rating		Ratio of Exciter to Unit Ratings	Exciter Capacity **(Note 4)** $	Unit Reactive Capacity Factor	Exciter Energy Consumption Cost $
	KVA	kW				
Column	14	15	16	17	18	19
Formula			= 15/2/1000	= 6*7*16		= 15/1000*8760*18*$51.00/MWh
Lingan 1	1430	858	0.57%	$3,838	74.34%	$284,965
Lingan 2	1430	858	0.57%	$3,838	68.82%	$263,786
Lingan 3	1430	858	0.57%	$5,644	72.26%	$277,006
Lingan 4	1430	858	0.57%	$5,644	71.26%	$273,161
Tufts Cove 1	639	383	0.38%	$1,278	77.05%	$131,987
Tufts Cove 2	424	255	0.25%	$1,225	68.30%	$77,695
Tufts Cove 3	1968	1181	0.79%	$5,217	56.81%	$299,718
Tufts Cove 4	413	248	0.46%	$5,660	40.00%	$44,319
Tufts Cove 5	413	248	0.46%	$2,247	40.00%	$44,319
Trenton 5	1402	841	0.56%	$1,947	67.18%	$252,487
Trenton 6	1700	1020	0.64%	$15,158	72.90%	$332,205
Pt. Tupper 2	1186	711	0.47%	$5,596	73.29%	$232,931
Pt. Aconi 1	1800	1080	0.58%	$13,006	65.90%	$317,975
Wreck Cove 1	575	345	0.35%	$624	9.00%	$13,872
Wreck Cove 2	575	345	0.35%	$624	9.00%	$13,872
Annapolis Tidal	86	51.57	0.30%	$555	10.20%	$2,350
Wind (Note 1)						
Other Hydro	1358	815	0.50%	$0	31.20%	$113,532
Burnside 1	169	102	0.34%	$266	1.60%	$726
Burnside 2	169	102	0.34%	$266	1.60%	$726
Burnside 3	169	102	0.34%	$266	1.60%	$726
Burnside 4	169	102	0.34%	$266	1.60%	$726
Victoria Junction 1	169	102	0.34%	$148	1.60%	$726
Victoria Junction 2	169	102	0.34%	$148	1.60%	$726
Tusket 1	169	102	0.42%	$377	1.60%	$726
TOTALS				$73,838		$2,981,263

Estimated Peak VAR Requirements (Col. 8)	485.0
Additional VAR Requirements for Dynamic System Security (Exhibit 6-5)	485.0
Total VAR Requirements	970.0
Total Reactive Support Costs - (Col.13+Col.17+Col.19)	$7,773,841
Ratio of VAR Requirements to Sum of Generator VAR Ratings (960/1080.5)	87.2%
Total Reactive Support Costs	**$6,780,351**

TABLE E4-3

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
REGULATION REVENUE REQUIREMENT

Unit	Generator Nameplate Capacity MW	Regulating Capacity MW	Regulating Ramp Rate MW/min	Time on AGC Hours	Regulating Capacity MWh	Ramp Rate Weighting Factor	Weighted Capacity to Regulate MWh	Participation Percentage	Net Book Value $/kW	Fixed Charge Rate	$/kW-yr	Weighted Annual Cost $/kW
Column	1	2	3	4	5	6	7	8	9	10	11	12
Formula		**(Note 1)**	**(Note 2)**	**(Note 3)**	= 2*4	= 3/(Sum of 3)	= 5*6	= 7/(Sum of 7)			= 9*10	= 8*11
Lingan 1	150	25	1.0	1,587.5	39688	1%	261	1%	$404.49	22.77%	$92.09	$ 1.02
Lingan 2	150	25	1.0	1,240.5	31013	1%	204	1%	$404.49	22.77%	$92.09	$ 0.80
Lingan 3	150	25	1.0	756.0	18900	1%	124	1%	$404.49	22.77%	$92.09	$ 0.49
Lingan 4	150	25	1.0	901.0	22525	1%	148	1%	$404.49	22.77%	$92.09	$ 0.58
Tufts Cove 1	100	10	1.0	0.0	0	1%	0	0%	$243.10	28.94%	$70.35	$ -
Tufts Cove 2	100	11	1.5	1,204.5	13250	1%	131	1%	$243.10	28.94%	$70.35	$ 0.39
Tufts Cove 3	150	52	1.5	2,299.5	119574	1%	1,180	5%	$243.10	28.94%	$70.35	$ 3.53
Tufts Cove 4 (Est.)	54	45	10.0	100.0	4500	7%	296	1%	$735.28	15.52%	$114.12	$ 1.43
Tufts Cove 5 (Est.)	54	45	10.0	100.0	4500	7%	296	1%	$289.44	15.65%	$45.30	$ 0.57
Trenton 5	150	30	1.0	560.0	16800	1%	111	0%	$699.66	21.05%	$147.26	$ 0.69
Trenton 6	160	25	2.0	960.5	24013	1%	316	1%	$699.66	21.05%	$147.26	$ 1.98
Pt. Tupper 2	150	70	1.0	500.0	35000	1%	230	1%	$535.14	24.95%	$133.52	$ 1.31
Pt. Aconi 1	185	0	0.0	0.0	0	0%	0	0%	$2,067.20	16.64%	$344.06	$ -
Wreck Cove 1	100	60	15.0	521.5	31290	10%	3,088	13%	$501.25	14.43%	$72.33	$ 9.49
Wreck Cove 2	100	60	15.0	2,122.5	127350	10%	12,567	53%	$501.25	14.43%	$72.33	$ 38.61
Annapolis Tidal	17.2	0	0.0	0.0	0	0%	0	0%	$1,373.09	15.68%	$215.32	$ -
Other Hydro	163	40	20.0	562.0	22480	13%	2,958	13%	$704.69	18.12%	$127.67	$ 16.04
Burnside 1	30	25	10.0	678.0	16950	7%	1,115	5%	$48.62	26.92%	$13.09	$ 0.62
Burnside 2	30	25	10.0	119.5	2988	7%	197	1%	$48.62	26.92%	$13.09	$ 0.11
Burnside 3	30	25	10.0	104.5	2613	7%	172	1%	$48.62	26.92%	$13.09	$ 0.10
Burnside 4	30	25	10.0	68.0	1700	7%	112	0%	$48.62	26.92%	$13.09	$ 0.06
Victoria Junction 1	30	25	10.0	10.0	250	7%	16	0%	$21.56	33.87%	$7.30	$ 0.01
Victoria Junction 2	30	25	10.0	10.0	250	7%	16	0%	$21.56	33.87%	$7.30	$ 0.01
Tusket 4	24	10	10.0	10.0	100	7%	7	0%	$76.40	24.30%	$18.57	$ 0.01
TOTALS	2287.2	708	152.0	14415.5	535731	100%	23,545	100%				$ 77.82

NOTES:

1. Capacity assigned to Automatic Generation Control.
2. Unit tested capability for ramping control
3. Two year average (SCADA records)

TABLE E4-4

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
LOAD FOLLOWING REVENUE REQUIREMENT

Unit	Type	Net Book Value $/kW	Fixed Charge Rate		Contribution to Load Following Winter morning MW-h	Unit Contribution	Weighted Annual Cost $/kW
	Column	1	2	3	4	5	6
	Formula			= 1*2		= 4/(Sum of 4)	= 3*5
Lingan 1	Thermal	$404.49	22.77%	$92.09	-	0%	$ -
Lingan 2	Thermal	$404.49	22.77%	$92.09	-	0%	$ -
Lingan 3	Thermal	$404.49	22.77%	$92.09	-	0%	$ -
Lingan 4	Thermal	$404.49	22.77%	$92.09	-	0%	$ -
Tufts Cove 1	Thermal	$243.10	28.94%	$70.35	-	0%	$ -
Tufts Cove 2	Thermal	$243.10	28.94%	$70.35	2,530	10%	$ 6.84
Tufts Cove 3	Thermal	$243.10	28.94%	$70.35	2,700	10%	$ 7.30
Tufts Cove 4	Thermal	$735.28	15.52%	$114.12	2,600	10%	$ 11.41
Tufts Cove 5	Thermal	$289.44	15.65%	$45.30	2,600	10%	$ 4.53
Trenton 5	Thermal	$699.66	21.05%	$147.26	-	0%	$ -
Trenton 6	Thermal	$699.66	21.05%	$147.26	-	0%	$ -
Pt. Tupper 2	Thermal	$535.14	24.95%	$133.52	-	0%	$ -
Pt. Aconi 1	Thermal	$2,067.20	16.64%	$344.06	-	0%	$ -
Wreck Cove 1	Hydro	$501.25	14.43%	$72.33	4,580	18%	$ 12.74
Wreck Cove 2	Hydro	$501.25	14.43%	$72.33	4,890	19%	$ 13.60
Annapolis Tidal	Hydro	$1,373.09	15.68%	$215.32	-	0%	$ -
Other Hydro	Hydro	$704.69	18.12%	$127.67	5,000	19%	$ 24.55
Burnside 1	LFO	$48.62	26.92%	$13.09	497	2%	$ 0.25
Burnside 2	LFO	$48.62	26.92%	$13.09	221	1%	$ 0.11
Burnside 3	LFO	$48.62	26.92%	$13.09	61	0%	$ 0.03
Burnside 4	LFO	$48.62	26.92%	$13.09	325	1%	$ 0.16
TOTALS					26,004	100%	$ 81.53

NOTES:

1. Average one-hour load pickup morning peak November - April (SCADA records)

TABLE E4-5
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NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SPINNING 10 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Generator Nameplate Capacity MW	Net Book Value $/KW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute
	Column	1	2	3	4	5	6	7	8	9
	Formula				= 2*3	**(Note 1)**	**(Note 2)**	= 5/6	**(Note 3)**	
Lingan 1	Thermal	150	$404.49	22.77%	$92.09	1,040,715	7715	134.9	0.927	1.0
Lingan 2	Thermal	150	$404.49	22.77%	$92.09	1,003,059	7909	126.8	0.860	1.0
Lingan 3	Thermal	150	$404.49	22.77%	$92.09	1,137,349	8352	136.2	0.934	1.0
Lingan 4	Thermal	150	$404.49	22.77%	$92.09	1,081,624	8098	133.6	0.905	1.0
Tufts Cove 1	Thermal	100	$243.10	28.94%	$70.35	560,323	6924	80.9	0.914	1.0
Tufts Cove 2	Thermal	100	$243.10	28.94%	$70.35	518,660	6212	83.5	0.888	1.5
Tufts Cove 3	Thermal	150	$243.10	28.94%	$70.35	694,260	6078	114.2	0.929	1.5
Tufts Cove 4	Gas	54	$735.28	15.52%	$114.12	25,000	500	50.0	0.950	10.0
Tufts Cove 5	Gas	54	$289.44	15.65%	$45.30	25,000	500	50.0	0.950	10.0
Trenton 5	Thermal	150	$699.66	21.05%	$147.26	958,504	7639	125.5	0.882	1.0
Trenton 6	Thermal	160	$699.66	21.05%	$147.26	1,198,512	8120	147.6	0.923	2.0
Pt. Tupper 2	Thermal	150	$535.14	24.95%	$133.52	1,111,341	8014	138.7	0.950	1.0
Pt. Aconi 1	Thermal	185	$2,067.20	16.64%	$344.06	1,371,043	7948	172.5	0.905	0.0
Wreck Cove 1	Hydro	100	$501.25	14.43%	$72.33	135,656	2508	54.1	0.980	15.0
Wreck Cove 2	Hydro	100	$501.25	14.43%	$72.33	146,713	2750	53.4	0.910	15.0
Annapolis Tidal	Hydro	17.2	$1,373.09	15.68%	$215.32	29,328	3523	8.3	0.950	0.0
Other Hydro	Hydro	163	$704.69	18.12%	$127.67	743,176	8760	84.8	0.500	20.0
Burnside 1	Diesel	30	$48.62	26.92%	$13.09	7,118	365	19.5	0.930	10.0
Burnside 2	Diesel	30	$48.62	26.92%	$13.09	5,763	292	19.8	0.964	10.0
Burnside 3	Diesel	30	$48.62	26.92%	$13.09	3,770	206	18.3	0.860	10.0
Burnside 4	Diesel	30	$48.62	26.92%	$13.09	6,253	307	20.4	0.968	10.0
Victoria Junction 1	Diesel	30	$21.56	33.87%	$7.30	1,171	58	20.2	0.973	10.0
Victoria Junction 2	Diesel	30	$21.56	33.87%	$7.30	1,928	95	20.4	0.973	10.0
Tusket 1	Diesel	24	$76.40	24.30%	$18.57	1,236	102	12.1	0.978	10.0
TOTALS		2287.2	$10,767.92			11,807,499		1,825.7		152.0

NOTES:

1. **Average 2002 - 2003**
2. **Average 2002 - 2003 (SCADA records)**
3. **Time available to operate, two year average**
4. **Non-firm exports assigned to units (2003)**

TABLE E4-5
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NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SPINNING 10 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Spinning Reserve (10 Minutes)						
		Response 0 - 10 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW
	Column	10	11	12	13	14	15	16
	Formula	= Min (1,9*10)		**(Note 4)**	= Max (0,Min(1-7,10))*6*11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	10.0	1	10,520	77,150	87,670	7%	$ 6.72
Lingan 2	Thermal	10.0	1	21,195	79,090	100,285	8%	$ 7.69
Lingan 3	Thermal	10.0	1	2,483	83,515	85,998	7%	$ 6.59
Lingan 4	Thermal	10.0	1	4,582	80,975	85,557	7%	$ 6.56
Tufts Cove 1	Thermal	10.0	0	26,934	-	26,934	2%	$ 1.58
Tufts Cove 2	Thermal	15.0	1	27,943	93,173	121,116	10%	$ 7.09
Tufts Cove 3	Thermal	15.0	1	33,206	91,170	124,376	10%	$ 7.29
Tufts Cove 4	Gas	54.0	0	351	-	351	0%	$ 0.03
Tufts Cove 5	Gas	54.0	0	351	-	351	0%	$ 0.01
Trenton 5	Thermal	10.0	1	15,872	76,390	92,262	8%	$ 11.31
Trenton 6	Thermal	20.0	1	5	100,688	100,693	8%	$ 12.35
Pt. Tupper 2	Thermal	10.0	1	30,989	80,140	111,129	9%	$ 12.35
Pt. Aconi 1	Thermal	0.0	0	613	-	613	0%	$ 0.18
Wreck Cove 1	Hydro	100.0	1	-	115,094	115,094	10%	$ 6.93
Wreck Cove 2	Hydro	100.0	1	-	128,288	128,288	11%	$ 7.73
Annapolis Tidal	Hydro	0.0	0	-	-	-	0%	$ -
Other Hydro	Hydro	163.0	0	-	-	-	0%	$ -
Burnside 1	Diesel	30.0	1	1,679	3,833	5,512	0%	$ 0.06
Burnside 2	Diesel	30.0	1	1,388	2,982	4,370	0%	$ 0.05
Burnside 3	Diesel	30.0	1	375	2,410	2,785	0%	$ 0.03
Burnside 4	Diesel	30.0	1	1,147	2,942	4,089	0%	$ 0.04
Victoria Junction 1	Diesel	30.0	1	367	569	936	0%	$ 0.01
Victoria Junction 2	Diesel	30.0	1	268	907	1,175	0%	$ 0.01
Tusket 1	Diesel	24.0	1	185	1,212	1,397	0%	$ 0.02
TOTALS				180,453	1,020,527	1,200,980	100%	$ 94.63

NOTES:

1. **Average 2002 - 2003**
2. **Average 2002 - 2003 (SCADA records)**
3. **Time available to operate, two year average**
4. **Non-firm exports assigned to units (2003)**

TABLE E4-6
Page 1 of 2

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SUPPLEMENTAL 10 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Generator Nameplate Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute
	Column	1	2	3	4	5	6	7	8	9
	Formula				= 2*3	**(Note 1)**	**(Note 2)**	= 5/6	**(Note 3)**	**(Note 4)**
Lingan 1	Thermal	150	$404.49	22.77%	$92.09	1,040,715	7,715.0	134.9	0.927	1.0
Lingan 2	Thermal	150	$404.49	22.77%	$92.09	1,003,059	7,909.0	126.8	0.860	1.0
Lingan 3	Thermal	150	$404.49	22.77%	$92.09	1,137,349	8,351.5	136.2	0.934	1.0
Lingan 4	Thermal	150	$404.49	22.77%	$92.09	1,081,624	8,097.5	133.6	0.905	1.0
Tufts Cove 1	Thermal	100	$243.10	28.94%	$70.35	560,323	6,924.0	80.9	0.914	1.0
Tufts Cove 2	Thermal	100	$243.10	28.94%	$70.35	518,660	6,211.5	83.5	0.888	1.5
Tufts Cove 3	Thermal	150	$243.10	28.94%	$70.35	694,260	6,078.0	114.2	0.929	1.5
Tufts Cove 4	Gas	54	$735.28	15.52%	$114.12	25,000	500.0	50.0	0.950	10.0
Tufts Cove 5	Gas	54	$289.44	15.65%	$45.30	25,000	500.0	50.0	0.950	10.0
Trenton 5	Thermal	150	$699.66	21.05%	$147.26	958,504	7,639.0	125.5	0.882	1.0
Trenton 6	Thermal	160	$699.66	21.05%	$147.26	1,198,512	8,120.0	147.6	0.923	2.0
Pt. Tupper 2	Thermal	150	$535.14	24.95%	$133.52	1,111,341	8,014.0	138.7	0.950	1.0
Pt. Aconi 1	Thermal	185	$2,067.20	16.64%	$344.06	1,371,043	7,947.5	172.5	0.905	0.0
Wreck Cove 1	Hydro	100	$501.25	14.43%	$72.33	135,656	2,507.5	54.1	0.980	15.0
Wreck Cove 2	Hydro	100	$501.25	14.43%	$72.33	146,713	2,750.0	53.4	0.910	15.0
Annapolis Tidal	Hydro	17.2	$1,373.09	15.68%	$215.32	29,328	3,523.0	8.3	0.950	0.0
Other Hydro	Hydro	163	$704.69	18.12%	$127.67	743,176	8,760.0	84.8	0.500	20.0
Burnside 1	Diesel	30	$48.62	26.92%	$13.09	7,118	365.0	19.5	0.930	10.0
Burnside 2	Diesel	30	$48.62	26.92%	$13.09	5,763	291.5	19.8	0.964	10.0
Burnside 3	Diesel	30	$48.62	26.92%	$13.09	3,770	206.0	18.3	0.860	10.0
Burnside 4	Diesel	30	$48.62	26.92%	$13.09	6,253	306.5	20.4	0.968	10.0
Victoria Junction 1	Diesel	30	$21.56	33.87%	$7.30	1,171	58.0	20.2	0.973	10.0
Victoria Junction 2	Diesel	30	$21.56	33.87%	$7.30	1,928	94.5	20.4	0.973	10.0
Tusket 1	Diesel	24	$76.40	24.30%	$18.57	1,236	102.0	12.1	0.978	10.0
TOTALS		2287.2	$10,767.92			11,807,499		1,825.7		152.0

NOTES:

1. **Average 2002 - 2003**
2. **Average 2002 - 2003 (SCADA records)**
3. **Time available to operate, two year average**
4. **Unit tested capability for ramping control**
5. **Non-firm exports assigned to units (2003)**

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SUPPLEMENTAL 10 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Supplemental 10 Minute Reserve						
		Response 0 - 10 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/KW
	Column	10	11	12	13	14	15	16
	Formula	= Min (1,9*10)		**(Note 5)**	Thermal = Max (0,Min(1-7,10))*6 *11 Hyd & Diesel = 1*8*8760 - 5 *11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	10.0	0	10,520	-	10,520	0%	$ 0.36
Lingan 2	Thermal	10.0	0	21,195	-	21,195	1%	$ 0.72
Lingan 3	Thermal	10.0	0	2,483	-	2,483	0%	$ 0.08
Lingan 4	Thermal	10.0	0	4,582	-	4,582	0%	$ 0.16
Tufts Cove 1	Thermal	10.0	0	26,934	-	26,934	1%	$ 0.70
Tufts Cove 2	Thermal	15.0	1	27,943	93,173	121,116	4%	$ 3.16
Tufts Cove 3	Thermal	15.0	1	33,206	91,170	124,376	5%	$ 3.25
Tufts Cove 4	Gas	54.0	0	351	-	351	0%	$ 0.01
Tufts Cove 5	Gas	54.0	0	351	-	351	0%	$ 0.01
Trenton 5	Thermal	10.0	0	15,872	-	15,872	1%	$ 0.87
Trenton 6	Thermal	20.0	0	5	-	5	0%	$ 0.00
Pt. Tupper 2	Thermal	10.0	0	30,989	-	30,989	1%	$ 1.54
Pt. Aconi 1	Thermal	0.0	0	613	-	613	0%	$ 0.08
Wreck Cove 1	Hydro	100.0	1	-	722,824	722,824	27%	$ 19.41
Wreck Cove 2	Hydro	100.0	1	-	650,448	650,448	24%	$ 17.47
Annapolis Tidal	Hydro	0.0	0	-	-	-	0%	$ -
Other Hydro	Hydro	163.0	0	-	-	-	0%	$ -
Burnside 1	Diesel	30.0	1	1,679	237,287	238,966	9%	$ 1.16
Burnside 2	Diesel	30.0	1	1,388	247,576	248,964	9%	$ 1.21
Burnside 3	Diesel	30.0	1	375	222,238	222,613	8%	$ 1.08
Burnside 4	Diesel	30.0	1	1,147	248,138	249,285	9%	$ 1.21
Victoria Junction 1	Diesel	30.0	0	367	-	367	0%	$ 0.00
Victoria Junction 2	Diesel	30.0	0	268	-	268	0%	$ 0.00
Tusket 1	Diesel	24.0	0	185	-	185	0%	$ 0.00
TOTALS				180,453	2,512,853	2,693,306	100%	$ 52.49

NOTES:

1. **Average 2002 - 2003**
2. **Average 2002 - 2003 (SCADA records)**
3. **Time available to operate, two year average**
4. **Unit tested capability for ramping control**
5. **Non-firm exports assigned to units (2003)**

TABLE E4-7
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NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SUPPLEMENTAL 30 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Installed Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute
	Column	1	2	3	4	5	6	7	8	9
	Formula				= 2*3	**(Note 1)**	**(Note 2)**	= 5/6	**(Note 3)**	**(Note 4)**
Lingan 1	Thermal	150	$404.49	22.77%	$92.09	1,040,715	7,715.0	134.9	0.927	1.0
Lingan 2	Thermal	150	$404.49	22.77%	$92.09	1,003,059	7,909.0	126.8	0.860	1.0
Lingan 3	Thermal	150	$404.49	22.77%	$92.09	1,137,349	8,351.5	136.2	0.934	1.0
Lingan 4	Thermal	150	$404.49	22.77%	$92.09	1,081,624	8,097.5	133.6	0.905	1.0
Tufts Cove 1	Thermal	100	$243.10	28.94%	$70.35	560,323	6,924.0	80.9	0.914	1.0
Tufts Cove 2	Thermal	100	$243.10	28.94%	$70.35	518,660	6,211.5	83.5	0.888	1.5
Tufts Cove 3	Thermal	150	$243.10	28.94%	$70.35	694,260	6,078.0	114.2	0.929	1.5
Tufts Cove 4	Gas	54	$735.28	15.52%	$114.12	25,000	500.0	50.0	0.950	10.0
Tufts Cove 5	Gas	54	$289.44	15.65%	$45.30	25,000	500.0	50.0	0.950	10.0
Trenton 5	Thermal	150	$699.66	21.05%	$147.26	958,504	7,639.0	125.5	0.882	1.0
Trenton 6	Thermal	160	$699.66	21.05%	$147.26	1,198,512	8,120.0	147.6	0.923	2.0
Pt. Tupper 2	Thermal	150	$535.14	24.95%	$133.52	1,111,341	8,014.0	138.7	0.950	1.0
Pt. Aconi 1	Thermal	185	$2,067.20	16.64%	$344.06	1,371,043	7,947.5	172.5	0.905	0.0
Wreck Cove 1	Hydro	100	$501.25	14.43%	$72.33	135,656	2,507.5	54.1	0.980	15.0
Wreck Cove 2	Hydro	100	$501.25	14.43%	$72.33	146,713	2,750.0	53.4	0.910	15.0
Annapolis Tidal	Hydro	17.2	$1,373.09	15.68%	$215.32	29,328	3,523.0	8.3	0.950	0.0
Other Hydro	Hydro	163	$704.69	18.12%	$127.67	743,176	8,760.0	84.8	0.500	20.0
Burnside 1	Diesel	30	$48.62	26.92%	$13.09	7,118	365.0	19.5	0.930	10.0
Burnside 2	Diesel	30	$48.62	26.92%	$13.09	5,763	291.5	19.8	0.964	10.0
Burnside 3	Diesel	30	$48.62	26.92%	$13.09	3,770	206.0	18.3	0.860	10.0
Burnside 4	Diesel	30	$48.62	26.92%	$13.09	6,253	306.5	20.4	0.968	10.0
Victoria Junction 1	Diesel	30	$21.56	33.87%	$7.30	1,171	58.0	20.2	0.973	10.0
Victoria Junction 2	Diesel	30	$21.56	33.87%	$7.30	1,928	94.5	20.4	0.973	10.0
Tusket 1	Diesel	24	$76.40	24.30%	$18.57	1,236	102.0	12.1	0.978	10.0
TOTALS		2287.2	$10,767.92			11,807,499		1,825.7		152.0

NOTES:

1. **Average 2002 - 2003**
2. **Average 2002 - 2003 (SCADA records)**
3. **Time available to operate, two year average**
4. **Unit tested capability for ramping control**
5. **Non-firm exports assigned to units (2003)**

TABLE E4-7
Page 2 of 2

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SUPPLEMENTAL 30 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Supplemental 30 Minute Reserve						
		Response 10 - 30 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW
	Column	10	11	12	13	14	15	16
	Formula	= Min (1,9*20)		**(Note 5)**	Thermal = Max (0,Min(1-7,10))*6*11 Hyd & Diesel = ((1*8*8760)- 5)*11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	20.0	1	10,520	116,535	127,055	9.51%	$ 8.75
Lingan 2	Thermal	20.0	1	21,195	158,180	179,375	13.42%	$ 12.36
Lingan 3	Thermal	20.0	1	2,483	115,376	117,859	8.82%	$ 8.12
Lingan 4	Thermal	20.0	1	4,582	133,001	137,583	10.29%	$ 9.48
Tufts Cove 1	Thermal	20.0	0	26,934	-	26,934	2.02%	$ 1.42
Tufts Cove 2	Thermal	30.0	1	27,943	102,490	130,433	9.76%	$ 6.86
Tufts Cove 3	Thermal	30.0	1	33,206	182,340	215,546	16.13%	$ 11.34
Tufts Cove 4	Gas	54.0	1	351	2,000	2,351	0.18%	$ 0.20
Tufts Cove 5	Gas	54.0	1	351	2,000	2,351	0.18%	$ 0.08
Trenton 5	Thermal	20.0	1	15,872	152,780	168,652	12.62%	$ 18.58
Trenton 6	Thermal	40.0	1	5	100,688	100,693	7.53%	$ 11.09
Pt. Tupper 2	Thermal	20.0	1	30,989	90,759	121,748	9.11%	$ 12.16
Pt. Aconi 1	Thermal	0.0	0	613	-	613	0.05%	$ 0.16
Wreck Cove 1	Hydro	100.0	0	-	-	-	0.00%	$ -
Wreck Cove 2	Hydro	100.0	0	-	-	-	0.00%	$ -
Annapolis Tidal	Hydro	0.0	0	-	-	-	0.00%	$ -
Other Hydro	Hydro	163.0	0	-	-	-	0.00%	$ -
Burnside 1	Diesel	30.0	0	1,679	-	1,679	0.13%	$ 0.02
Burnside 2	Diesel	30.0	0	1,388	-	1,388	0.10%	$ 0.01
Burnside 3	Diesel	30.0	0	375	-	375	0.03%	$ 0.00
Burnside 4	Diesel	30.0	0	1,147	-	1,147	0.09%	$ 0.01
Victoria Junction 1	Diesel	30.0	0	367	-	367	0.03%	$ 0.00
Victoria Junction 2	Diesel	30.0	0	268	-	268	0.02%	$ 0.00
Tusket 1	Diesel	24.0	0	185	-	185	0.01%	$ 0.00
TOTALS				180,453	1,156,149	1,336,602	100.00%	$ 100.66

NOTES:

1. Average 2002 - 2003
2. Average 2002 - 2003 (SCADA records)
3. Time available to operate, two year average
4. Unit tested capability for ramping control
5. Non-firm exports assigned to units (2003)

TABLE E4-8

NOVA SCOTIA POWER INC.
EMBEDDED VS PROXY COST OF ANCILLARY SERVICES
REVENUE REQUIREMENT SUMMARY

	EMBEDDED		PROXY	
Service	**Unit Revenue Requirement**		**Unit Revenue Requirement**	
Voltage Control and Reactive Supply	$6,780,351	$/yr	$8,065,300	$/yr
Regulation Cost	$77.82	$/kW-yr	$43.05	$/kW-yr
Load Following Cost	$81.53	$/kW-yr	$43.05	$/kW-yr
Operating Reserve - Spinning	$94.63	$/kW-yr	$77.49	$/kW-yr
Operating Reserve - Supplemental - 10 Minute	$52.49	$/kW-yr	$53.60	$/kW-yr
Operating Reserve - Supplemental - 30 Minute	$100.66	$/kW-yr	$53.60	$/kW-yr
	Total Revenue Requirement		**Total Revenue Requirement**	
Voltage Control and Reactive Supply	$6,780	$000/yr	$8,065	$000/yr
Regulation Cost	2,023	$000/yr	1,119	$000/yr
Load Following Cost	11,578	$000/yr	6,113	$000/yr
Operating Reserve - Spinning	2,366	$000/yr	1,937	$000/yr
Operating Reserve - Supplemental - 10 Minute	5,249	$000/yr	5,360	$000/yr
Operating Reserve - Supplemental - 30 Minute	5,033	$000/yr	2,680	$000/yr
Total Annual Revenue Requirement	**$33,030**	$000/yr	**$25,275**	$000/yr

ATTACHMENT E

Standards of Conduct

Nova Scotia Power Inc.

STANDARDS OF CONDUCT
For the Provision of Wholesale
Electric Transmission Service

These Standards of Conduct are applicable to Nova Scotia Power and its employees and the employees of its Affiliates. These Standards of Conduct govern Nova Scotia Power's relationships with its transmission customers and potential customers, including employees of Nova Scotia Power and its Affiliates.

These Standards of Conduct are based on FERC Order 2004 and its subsequent re-hearings and clarifications. Order 889 was issued in conjunction with FERC Order 888 regarding non-discriminatory transmission open access; Order 2004 further clarifies Order 889.

DEFINITIONS:

Affiliate: For the purposes of these Standards of Conduct, the term "affiliate" shall be interpreted in accordance with Sections 2(2), 2(3), and 2(4) of the Nova Scotia Companies Act[3].

[3] **Deemed affiliate**
2(2) A company shall be deemed to be an affiliate of another company if one of them is the subsidiary of the other or if both are subsidiaries of the same company or if each of them is controlled by the same person.
Deemed control
2(3) A company shall be deemed to be controlled by another person or by two or more companies if
(a) voting securities of the first-mentioned company carrying more than fifty per cent of the votes for the election of directors are held, otherwise than by way of security only, by or for the benefit of the other person or by or for the benefit of the other companies; and

Energy Control Centre: means the facilities located in Halifax, Nova Scotia, which are used by the transmission services scheduling agent, the Operating Area operator, the bulk transmission system operator and the real time generation dispatch group for the Nova Scotia Power integrated system.

Marketing, Sales or Brokering: means a sale for resale of electric energy. Sales and Marketing employee or unit includes Nova Scotia Power's energy sales unit, unless such unit engages solely in bundled retail sales.

Open Access Same-time Information System or OASIS: refers to the Internet location where Nova Scotia Power posts the information by electronic means[4].

Operating Area: means the Nova Scotia transmission system, bounded by the Nova Scotia – New Brunswick border, under the control of the Nova Scotia Power Energy Control Centre. The Nova Scotia Operating Area is a part of the Maritimes Control Area as defined by the Northeast Power Coordinating Council.

Transmission: means electric transmission, network or point-to-point service, reliability service, ancillary services or other methods of transportation or the interconnection with jurisdictional transmission facilities.

(b) the votes carried by such securities are entitled, if exercised, to elect a majority of the directors of the first-mentioned company.

Deemed subsidiary

2(4) A company shall be deemed to be a subsidiary of another company if

(a) it is controlled by

(i) that other, or

(ii) that other and one or more companies each of which is controlled by that other, or

(iii) two or more companies each of which is controlled by that other; or

(b) it is a subsidiary of a company that is that others subsidiary. R.S., c. 81, s. 2; 1990, c.15, s. 2.

[4] The functions of an OASIS related to the reservation of transmission capacity on the Nova Scotia transmission system will not be activated until a Transmission Tariff is established. The Nova Scotia Power OASIS will however provide other relevant transmission information as required by these Standards of Conduct.

<u>Transmission Customer</u>: means any eligible customer, 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.

<u>Transmission Function Employee</u>: means an employee, contractor, consultant or agent of Nova Scotia Power who conducts transmission system operations or reliability functions, including, but not limited to, those who are engaged in day-to-day duties and responsibilities for planning, directing, organizing or carrying out transmission-related operations.

<u>Transmission System Operations or Reliability Functions</u>: means the direct act of operating the Nova Scotia transmission system to provide transmission services according to an approved transmission tariff and the reliability rules of the Northeast Power Coordinating Council.

<u>Transmission Provider</u>: means an entity (or its designated agent) that owns, controls, or operates facilities used for the transmission of electric energy and provides transmission services.

<u>Transmission System:</u> means all facilities for transporting electrical power, designed and operated at nominal voltages of 69kV and above.

A. GENERAL RULES:

1. Transmission Function employees must function independently of Nova Scotia Power's Marketing and Sales employees, and from any employees of its Affiliates.

2. Transmission Function employees must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and must not operate its transmission system to preferentially benefit an Affiliate.

B. INDEPENDENT FUNCTIONING:

1. **Separation of Functions**

a) Except in emergency circumstances affecting system reliability, Transmission Function Employees must function independently of Nova Scotia Power's Marketing and Sales or Affiliates' employees.

b) Notwithstanding any other provisions in this section, in emergency circumstances affecting system reliability, Transmission Function Employees must post on the OASIS each emergency that resulted in any deviation from the standards of conduct, within 24 hours of such deviation.

c) Employees of Nova Scotia Power's Affiliates or Marketing and Sales function are prohibited from:

i) conducting Transmission System Operations or Reliability Functions; and

ii) having access to the Energy Control Centre, or similar facilities used for Transmission System Operations or Reliability Functions, that differs in any way from the access available to other Transmission Customers.

d) Nova Scotia Power is permitted to share support employees and field and maintenance employees with their Marketing and Affiliates.

2. **Identifying Affiliates on the Public Internet**

a) Nova Scotia Power must post the names and addresses of its Marketing and Sale units and Affiliates on its OASIS.

b) Nova Scotia Power must post on its OASIS a complete list of the facilities shared by Transmission Function Employees and employees of its Marketing and Sales units or Affiliates, including the types of facilities shared and their addresses.

c) Nova Scotia Power must post comprehensive organizational charts showing:

i) The organizational structure of the parent corporation with the relative position in the corporate structure of the Transmission Function, Marketing and Sales units and any Affiliates;

ii) For Nova Scotia Power's Transmission Function, the business units, job titles and descriptions, and chain of command for all positions, including officers and directors, with the exception of clerical, maintenance, and field positions. The job titles and descriptions must include the employee's title, the employee's duties, whether the employee is involved in transmission or sales, and the name of the supervisory employees who manage non-clerical employees involved in transmission or sales.

iii) For all employees who are engaged in Transmission Functions for Nova Scotia Power and Marketing and Sales functions, or who are engaged in Transmission Functions for Nova Scotia Power and are employed by any of the Affiliates, Nova Scotia Power must post the name of the business unit within the Marketing and Sales unit or the

Affiliate, the organizational structure in which the employee is located, the employee's name, job title and job description in the Marketing and Sales unit or Affiliate, and the employee's position within the chain of command of the Marketing and Sales unit or Affiliate.

iv) Nova Scotia Power must update the information on its OASIS, required by Section B (2), (a), (b) and (c) within seven business days of any change, and post the date on which the information was updated.

v) Nova Scotia Power must post information concerning potential merger partners as Affiliates within seven days after the merger is announced.

d) **Transfers**

Transmission Function Employees and employees of Nova Scotia Power's Marketing and Sales units or Affiliates are not precluded from transferring among such functions as long as such transfer is not used as a means to circumvent these Standards of Conduct. Notices of any employee transfers must be posted on the OASIS. The information to be posted must include: the name of the transferring employee, the respective titles held while performing each function (i.e. on behalf of the Transmission Function, Marketing and Sales function or Affiliate), and the effective date of the transfer. The information posted under this section must remain on the OASIS for 90 days.

e) **Written Procedures**

i) Nova Scotia Power must post on the OASIS current written procedures for implementing the Standards of Conduct in sufficient detail to enable customers to determine that Nova Scotia Power is in compliance with the Standards of Conduct.

ii) Nova Scotia Power will distribute the written procedures to all its employees and employees of its Affiliates.

iii) Nova Scotia Power shall require all applicable employees, covered by the Standards of Conduct, to attend training and sign a document certifying that they have been trained regarding the requirements of the Standards of Conduct.

iv) Nova Scotia Power shall designate a Chief Compliance Officer who will be responsible for Standards of Conduct compliance.

3. **Non-discrimination requirements**

a) **Information Access**

i) Employees of Nova Scotia Power engaged in Marketing and Sales or any employee of an Affiliate may have access only to information which is available to Nova Scotia Power's transmission customers (i.e., the information posted on the OASIS), and must not have access to any information about Nova Scotia Power's transmission system that is not available to all users of the OASIS.

ii) Nova Scotia Power must ensure that any employee who is engaged in Marketing and Sales or any employee of an Affiliate is prohibited from obtaining information about Nova Scotia Power's transmission system (including, but not limited to, information about available transmission capability, price, curtailments, ancillary services, balancing, maintenance activity, capacity expansion plans or similar information) through access to information not posted on the OASIS or that is not otherwise also available to the general public without restriction.

b) **Prohibited Disclosure**

i) Transmission Function Employees may not disclose to Nova Scotia Power's Marketing and Sales employees, or to employees of Affiliates any information concerning the transmission system of Nova Scotia Power or the transmission system of another (including, but not limited to, information received from non-affiliates or information about available transmission capability, price, curtailments, storage, ancillary services, balancing, maintenance activity, capacity expansion plans, or similar information) through non-public communications conducted off the OASIS that are not contemporaneously available to the public, or through information on the OASIS that is not at the same time publicly available.

ii) Transmission Function Employees may not share any information, acquired from nonaffiliated transmission customers or potential nonaffiliated transmission customers, or developed in the course of responding to requests for transmission or ancillary service on the OASIS, with employees of its Marketing and Sales unit or

Affiliates, except to the limited extent information is required to be posted on the OASIS in response to a request for transmission service or ancillary services.

iii) If a Transmission Function Employee discloses information in a manner contrary to the requirements of s. B, 3(b), (i) or (ii) Nova Scotia Power must immediately post such information on the OASIS.

iv) A non-affiliate transmission customer may voluntarily consent, in writing, to allow Nova Scotia Power's Transmission Function to share the non-affiliated customer's information with Marketing and Sales or an Affiliate.

v) Nova Scotia Power is not required to contemporaneously disclose to all transmission customers or potential transmission customers information covered by s. B, 3(b), (i) if it relates solely to a Marketing and Sales or an Affiliate's specific request for transmission service.

vi) Nova Scotia Power's Transmission Function may share generation information necessary to perform generation dispatch with its Marketing and Sales units and Affiliates that does not include specific information about individual third party transmission transactions or potential transmission arrangements.

vii) Transmission Function Employees are not permitted to use anyone as a conduit for sharing information covered by the prohibitions of s. B, 3(b), (i) or (ii) with Marketing and Sales or an Affiliate.

viii) Nova Scotia Power is permitted to share crucial operating information with its Affiliate to maintain the reliability of the transmission system.

c) **Implementing Tariffs**.

i) Transmission Function Employees must strictly enforce all tariff provisions relating to open access transmission service if these tariff provisions do not permit the use of discretion.

ii) Transmission Function Employees must apply all tariff provisions relating to open access transmission service in a fair and impartial manner that treats all transmission customers in a non-discriminatory manner if these tariff provisions permit the use of discretion.

iii) Transmission Function Employees must process all similar requests for transmission in the same manner and within the same period of time.

iv) Nova Scotia Power must maintain a written log detailing the circumstances and manner in which it exercised its discretion under any terms of the tariff. The information contained in this log is to be posted on the OASIS within 24 hours of when Nova Scotia Power's Transmission Function exercises its discretion under any terms of the tariff.

v) Nova Scotia Power may not, through its tariffs or otherwise, give preference to its own Marketing and Sales function or to any Affiliate, over any other wholesale customer 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) **Discounts**

Any offer of a discount for any transmission service made by Nova Scotia Power must be posted on the OASIS contemporaneously with the time that the offer is contractually binding. The posting must include: the name of the customer involved in the discount and whether it is an affiliate or whether an affiliate is involved in the transaction, the rate offered; the maximum rate, the time period for which the discount would apply; the quantity of power or gas scheduled to be moved; the delivery points under the transaction; and any conditions or requirements applicable to the discount. The posting must remain on the OASIS for 60 days from the date of posting.

ACKNOWLEDGEMENT

I acknowledge that I have read the Standards of Conduct that functionally separate the Transmission System Operations and Reliability Functions from the Marketing, Sales and Affiliates Functions and I agree to comply fully with them.

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Name

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Signature