Énergie NB Power

New Brunswick
Electricity Business Rules

Chapter 4
Billing and Payment

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CHAPTER 4 – BILLING AND PAYMENT

4.1 Billing and Payment

4.1.1 Billing of, and payment to, Transmission Users shall be performed in accordance with the Open Access Transmission Tariff (the "Tariff"). Additional details provided within these Electricity Business Rules (the "Business Rules") are intended to provide clarity and more specificity.

4.1.2 The System Operator (the "SO") shall perform settlement calculations and prepare settlement statements for all Transmission Users. Settlement within the Corporation, including transactions with the SO will not be subject to invoicing and payment, but will be recorded as book entries only. Settlement between the SO and the Corporation's Affiliates will be subject to invoicing and payment.

4.2 Metering Data Management

4.2.1 Transmitters shall provide to the SO, or make available for automated transfer, metering data in accordance with the requirements of the Tariff and the Business Rules in accordance with the billing and payment timing identified herein.

4.2.2 Metering data is the confidential property of the SO.

4.2.3 Metering data, including meter output data and all error corrections and adjustments, shall be made available in a reasonable and convenient form to the SO and to any Transmission User whose settlement under the Tariff or the Business Rules is directly dependent on such metering data.

4.3 Timing of Billing and Payment

4.3.1 The process of billing and payment under the Tariff shall be performed in accordance with the timeline that is contained in the following table. The timing is defined in terms of Business Days following the month in which the billing and payment obligations were incurred.

Table A

Timing of Billing and Payment

Deadline	Responsible Entity	Activity
End of First Business Day	Transmitters	Make metering data available to the SO including with respect to load transfers.
End of Fourth Business Day	SO	Process metering data (e.g. adjust, review, correct, estimate, and aggregate as required). Calculate and issue preliminary charges and payments to payers and payees.
Noon of Fifth Business Day	Transmitter and Transmission Users	Review relevant preliminary charges and payments. Alert SO of suspected errors in the posted charges and payments.
End of Fifth Business Day	SO	Make required corrections to charges and payments calculations and reissue. Issue invoices.
As per Tariff	Transmission Users	Make Tariff payments as per the Tariff and invoices.
As per the applicable contract	SO	Make payments for services provided in accordance with relevant contracts.

4.4 Billing in Accordance with the Tariff

4.4.1 Billing for services under the Tariff shall be performed in accordance with the Tariff, subject to additional clarification or details as specified herein.

4.5 Allocation of Tariff Revenues to Transmitters

4.5.1 The SO shall allocate revenue received from Transmission Customers as payment for use of the transmission system to Transmitters in proportion to their respective revenue requirements as approved by the Board.

4.5.2 The SO shall allocate revenue received from Transmission Customers as payment for power factor penalties in accordance with the Tariff to the Transmitter that owns the transmission system to which the Facility incurring the power factor penalty is connected.

4.6 Payments to Third Party Suppliers of Reactive Supply and Voltage Control

4.6.1 Payments to suppliers of Reactive Supply and Voltage Control capability by the SO will be made in accordance with contracts. The following principles apply to any new or revised contracts for the provision of Reactive Supply and Voltage Control from Facilities that are not owned by the Corporation.

- All Facilities shall provide the service in accordance with Attachment J of the Tariff, the Generation Connection Agreement, and Appendix E of the Business Rules, Ancillary Services Operational Requirements ;
- All Facilities providing the service shall be eligible for compensation provided that a contract is in effect;
- Compensation shall be on the basis that all new providers are compensated equally for the same service;
- The SO shall not compensate more than one party for provision of the same service over the same period of time from the same Facility.
- The SO shall have no obligation to establish or maintain additional compensation to the owner or operator of a Facility for provision of the service should a compensation arrangement with the owner or operator already be in place for the service from the Facility; and

- To the extent feasible, compensation by the SO to the owner or operator of a Facility shall be consistent with the unit price and provision metric inherent in the cost of service study for the most recently approved Tariff charges for Reactive Supply and Voltage Control service.

4.6.2 The SO shall credit to the Corporation the full amounts collected for services under the Tariff for Reactive Supply and Voltage Control capability, less the compensation paid by the SO to suppliers of Reactive Supply and Voltage Control from Facilities not owned by the Corporation.

4.7 Provision of Capacity-Based Ancillary Services

4.7.1 Given that the Corporation is the exclusive provider of Capacity-Based Ancillary Services with respect to requirements that are not met through SO approved Transmission Customer arranged services (i.e. Transmission Customer self-supply or Transmission Customer arranged supply by another party), the SO does not pay Third Party suppliers for provision of Capacity-Based Ancillary Services. Similarly, the SO does not use these services of Third Party suppliers other than with respect to SO approved Transmission Customer arranged services or emergency conditions.

4.7.2 In the case of a Transmission Customer's self-supply of Capacity Based Ancillary Services, compensation for energy produced upon activation will be the same as for imbalance.

4.8 Payments for Third Party Generation Facility Re-dispatch Energy

4.8.1 The SO will pay/charge owners of Third Party Generation Facilities for energy Re-dispatch based on their incremental costs, which may include start-up and minimum run costs, and energy costs. Opportunity costs can be included upon request of the owner of the Third Party Generation Facility. Payment or charge for any such opportunity costs will be subjected to an audit at the SO's discretion by an independent reviewer selected by the SO and the owner. Should the audit indicate that the opportunity costs are unsubstantiated the owner shall reimburse the SO for the cost of audit and the payment/charge for the Re-dispatch shall be corrected.

4.8.2 The quantity of eligible Re-dispatch of a Third Party Facility in any hour in MWh is the difference between the Dispatch Instruction and the scheduled output from a given Third Party Facility indicated by all Balanced Schedules.

4.8.3 The quantity of eligible Third Party Re-dispatch energy will be positive if the Dispatch Instruction is greater than the scheduled output indicated by all Balanced Schedules, and negative if the Dispatch Instruction is less than the scheduled output indicated by all Balanced Schedules.

4.8.4 The charge (in the case of negative Re-dispatch), or credit (in the case of positive Re-dispatch), to a third-party that has been subject to Re-dispatch shall be equal to the quantity of eligible third-party Re-dispatch energy multiplied by the customer's previously submitted expected variable fuel and operation and maintenance cost per MWh of compliance with the Re-dispatch instruction, or in the case that a submission of actual costs has been made within the first 3 Business Days following the calendar month in which the Re-dispatch occurred, the customer's post-dispatch submission of actual variable fuel and operation and maintenance cost per MWh of compliance with the Re-dispatch instruction, which may include reference to previously filed cost information and must not differ from the expected value by any more than +/-20%.

4.8.5 Section 4.8 is not applicable in those occasions where a Third Party Generation Facility included in an Ancillary Service self-supply schedule is dispatched by the SO to activate CBAS where said dispatch results in an injection of energy to the IES. Any additional energy generated by Third Party Generation Facilities as a result of activation for CBAS will be treated as Energy Variance as described in section 4.10.

4.9 Credits to the Corporation for Net Re-dispatch

4.9.1 The Corporation fulfills all Energy Imbalance requirements except those fulfilled by re-dispatch of other third Party Generation Facilities.

4.9.2 The SO shall credit or charge the full amounts collected for services under the Tariff that are inherently provided using Re-dispatch energy (e.g. energy imbalance, ancillary services out-of-order dispatch, congestion management, schedule rounding amounts) to the Corporation, less the net amount of settlement with other Third Party Generation Facilities Re-dispatch.

4.10 Energy Imbalance (Variance) and Schedule Rounding Amounts

4.10.1 The SO shall determine Settlement Amounts for actual energy imbalances (variances) and associated costs as follows:

a) The SO shall determine, on the basis of metering data, for each Generation Facility for each hour the Imbalance Quantity - Generation (IQG), which shall be the quantity of any actual variance in the output of energy by that Generation Facility relative to its Dispatch Instructions;

b) The SO shall charge or credit each Generation Facility that has an IQG in a given hour at the FHMC;

c) The SO shall determine, on the basis of metering data, for each Load Facility or corresponding Virtual Delivery Point for each hour the Imbalance Quantity - Load (IQL), which shall be the difference between the actual or imputed hourly metering data for that Load Facility or Virtual Delivery Point and the energy quantity in the Final Hourly Balanced Schedule or FHBS;

d) The SO shall charge or credit each Load Facility that has an IQL in a given hour at the price indicated by the Tariff for that hour at the FHMC, multiplied by the applicable loss factor specified in the Tariff; and

e) Variances in the import or export flows on Radial Interconnections shall, after accounting for inadvertent flows in accordance with the provisions of applicable Interconnection Agreements, be treated in the same manner as variances in respect of Generation Facilities and Load Facilities, respectively.

4.10.2 The SO shall determine the schedule rounding error for each hour in accordance with the following formula:

Q(injection) – [Q(withdrawal) * (1 + transmission loss factor)]

rounded to the nearest kWh.

4.10.3 The SO shall determine the Schedule Rounding Amount (SRA) due in each hour to each Transmission Customer as the schedule rounding error determined in accordance with this section multiplied by FHMC for each of the Transmission Customer's Balanced Schedules.

4.10.4 The net amount payable to a Facility under section 4.10.1(b) or 4.10.1(d) shall be the Actual Energy Variance Settlement Credit or "AEVSC" (or "AEVSCG" for Generation Facilities and "AEVSCL" for Load Facilities).

4.11 Ancillary Services Re-dispatch and Congestion Management Costs

4.11.1 The SO shall determine the Day Ahead energy Re-dispatch costs as follows:

a) The SO shall determine an optimized Day Ahead, energy only unconstrained Commitment Schedule, referred to as "DAEOUS", using data identical to that used in determining the Final Day Ahead Commitment Schedule except that CBAS dispatch requirements are reduced by any CBAS obligations for Load Facilities (including External Load Facilities), Incremental Operating

Reserve and Wind facilities, and all Transmission constraints within the Province shall be ignored;

b) The SO shall determine an optimized Day Ahead, energy and Ancillary Services unconstrained Commitment Schedule, referred to as "DAEAUS", using data identical to that used in determining the Final Day Ahead Commitment Schedule except that all Transmission constraints within the Province shall be ignored;

c) The SO shall determine an optimized Day Ahead, energy and Ancillary Services unconstrained Commitment Schedule with the Incremental Operating Reserve obligations removed, referred to as "DAEAUS*", using data identical to that used in determining the Final Day Ahead Commitment Schedule except that all Transmission constraints within the Province shall be ignored and CBAS dispatch requirements are reduced by the total Incremental Operating Reserve obligation;

d) The SO shall determine an optimized Day Ahead, energy and Ancillary Services unconstrained Commitment Schedule with CBAS for Wind requirements removed, referred to as "DAEAUS~", using data identical to that used in determining the Final Day Ahead Commitment Schedule except that all Transmission constraints within the Province shall be ignored and Ancillary Service dispatch requirements are reduced by the total Incremental Operating Reserve obligation and by the total CBAS for Wind obligation;

e) The SO shall calculate the total generation cost, consisting of start-up costs, minimum run costs and incremental energy costs above minimum run quantity, for each corresponding Dispatch Day associated with each of the following Commitment Schedules:

   i. The DAEOUS, for which the cost shall be designated as "DAEOUC"
   ii. The DAEAUS, for which the cost shall be designated as "DAEAUC"
   iii. The DAEAUS*, for which the cost shall be designated as "DAEAUC*"

iv. The DAEAUS~, for which the cost shall be designated as "DAEAUC~"

v. The Final Day Ahead Commitment Schedule, for which the cost shall be designated as "FDACC"

f) The SO shall calculate the total Ancillary Service Re-dispatch Cost (ASRC), which shall be DAEAUC minus DAEOUC;

g) The SO shall calculate the total Ancillary Service Re-dispatch Cost attributed to Incremental Operating Reserves (ASRC*), which shall be DAEAUC minus DAEAUC*;

h) The SO shall calculate the total Ancillary Service Re-dispatch Cost attributed to Wind Facilities (ASRC~), which shall be DAEAUC* minus DAEAUC~

i) The SO shall calculate the total Congestion Management Cost (CMC), which shall be FDACC minus DAEAUC; and

j) Where the Final Day Ahead Balanced Schedule schedules a Generation Facility to have a total output that is not zero and lies outside the possible range as known by the SO, then the values of each of DAEOUC, DAEAUC*, DAEAUC~, DAEAUC and FDACC shall be calculated on the basis that such Schedule requires the Generation Facility to be operating and using a re-dispatch price of zero for all energy outside of the possible operating range.

4.11.2 The SO will calculate that portion of Ancillary Service Re-dispatch costs to be attributed to all Load Facilities (including External Load Facilities) having a CBAS obligation under the Tariff as the total Re-dispatch cost (ASRC) less that portion attributed to Incremental Operating Reserve (ASRC*) and that portion attributed to Wind (ASRC~).

4.11.3 The SO shall allocate the portion of ASRC attributed to Load Facilities (including External Load Facilities) to individual Ancillary Services as follows:

a) The SO shall determine the total quantity, in MWh, of each Ancillary Service scheduled in the FDACS to be provided on the corresponding Dispatch Day and shall determine the equivalent quantity of Load Following Service for each such Ancillary Service as follows:

i. Each MWh of Automatic Generation Control Service (AGC) shall be deemed to be equivalent to 1.25 MWh of Load Following Service;

ii. Each MWh of 10-minute spinning Operating Reserve Service shall be deemed to be equivalent to 0.75 MWh of Load Following Service;

iii. Each MWh of 10-minute non-spinning Operating Reserve Service shall be deemed to be equivalent to 0.50 MWh of Load Following Service; and

iv. Each MWh of 30-minute Operating Reserve Service shall be deemed to be equivalent to 0.40 MWh of Load Following Service;

b) The SO shall determine the ASRC for each MWh of equivalent Load Following Service and shall allocate the ASRC accordingly to each class of Ancillary Service for the Dispatch Day; and

c) The SO shall thus determine the total for each Settlement Period of the re-dispatch costs that are attributed to Load Facilities (including External Load Facilities) associated with each Ancillary Service.

4.11.4 The SO shall determine the Ancillary Service re-dispatch Settlement Amounts to be debited to each Load having a CBAS obligation in respect of each of AGC, Load Following Service and all three classes of Operating Reserve Service. The debits are calculated as follows:

i. The rate per MWh for each type of Ancillary Service is calculated as the portion of ASRC for Load Facilities (including External Load Facilities) attributed to that Ancillary Service type in 4.11.3 above divided by the total MWh obligation for all Load Facilities (including External Load Facilities) for that Ancillary Service type

ii. The debit for each Load Facility (including External Load Facilities) and Ancillary Service type is then calculated as the obligation MWh for that Load Facility (including External Load Facilities) and Ancillary Service type that was not self-supplied, multiplied by the rate per MWh for that type of Ancillary Service determined above in (i).

4.11.5 The SO shall allocate the Incremental Reserve Re-dispatch cost (ASRC*) amongst the Transmission Customers responsible for the transactions that triggered the incremental Operating Reserve requirement as a debit in proportion to each such Transmission Customer's contribution to the total requirement of each class of Operating Reserve after accounting for any SO approved self-supply arrangements made by each Transmission Customer.

4.12 Residual Uplift

4.12.1 Residual Uplift is deemed to be zero.

4.13 Final Hourly Marginal Cost

4.13.1 The FHMC is the marginal cost saving to the system that would have been achieved if system primary demand had been reduced by 1 MW .