



NEW BRUNSWICK SYSTEM OPERATOR

Market Settlement and Billing

**Review of the NBSO
Settlement Process**

December 15, 2009



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Introduction

NBSO is a not-for-profit independent corporation whose primary responsibilities are to ensure the reliability of the electrical system and to facilitate the development and operation of a competitive electricity market in New Brunswick.

The New Brunswick Electricity Market is a physical bilateral market for injections and withdrawals at the boundaries of the electric power transmission system in New Brunswick. The market is built upon the foundation of a FERC Order 888 type open access transmission tariff. Deliveries of transactions between market participants are implemented by NBSO in accordance with schedules submitted by the market participants.

The New Brunswick System Operator (NBSO) is responsible for administering the New Brunswick Transmission System and to facilitate the efficient and reliable supply of the electricity in New Brunswick. The NBSO facilitates and charges participants for access to the New Brunswick Transmission System through an OATT (Open Access Transmission Tariff).

The NBSO Settlement function is the calculation and invoicing of all debits and credits associated with the NBSO Open Access Transmission Tariff and the NB Electricity Market Rules. The Settlement function is performed in accordance with the NB Open Access Transmission Tariff, the NB Electricity Market Rules, and the relevant contracts between NBSO and its contract counterparties.

The Market Rules complement and supplement the Transmission Tariff by further defining and interpreting the rights and obligations.

PricewaterhouseCoopers LLP (PwC) was contracted to provide an independent review of the operation and application of the electricity settlement system and related processes. Subsequently, PwC evaluated the settlement system and related processes to assess whether it meets the requirements of section 7.2.5 and section(s) 7.4 – 7.15 of Chapter 7 of the market rules. This report communicates the results of the review performed for the settlement month of January 2009.

Scope of Review

Our review included a review of the settlement system and related processes as described in market rules 7.4 – 7.15 of the Electricity Market Rules governing New Brunswick. Accordingly, the validity or accuracy of all inputs to the MSB (settlement system) was outside the scope of our review.



PwC's Review Approach

We performed the review in accordance with standards for review engagements established by the Canadian Institute of Chartered Accountants. Our review consisted primarily of enquiry, analytical procedures and discussion related to information supplied to us by the NBSO. This included primarily of the following activities:

- Review of Transmission Tariff and Market rules related to Settlement
- Interviewing IESO personnel responsible for the use, maintenance, and monitoring of the settlement system and processes employed by NBSO
- Reviewing settlement and implementation documentation including design and functional requirement specifications, user guides, and NBSO operating procedures.
- Re-performance of settlement calculations using data obtained from NBSO personnel
- Comparison of PwC results with NBSO settlement amounts

At each stage in the process, we reviewed and discussed exceptions and anomalies detected during the testing process with NBSO staff and resolved all potentially material issues identified.

Review Engagement Report

To the NBSO Board of Directors:

We have reviewed the New Brunswick System Operator (NBSO)'s settlement system and related processes' compliance with section 7.2.5 and section(s) 7.4 - 7.15 of Chapter 7 of the Market Rules inclusive of the interpretations made by NBSO Management for the settlement period of February, 2009. Management's interpretations of the rules and the text of the relevant sections of the Market rules are set out in the following pages of this report. Our review was made in accordance with generally accepted standards for review engagements and accordingly consisted primarily of enquiry, analytical procedures and discussion related to information supplied to us by the NBSO. Our review process is further described in the following section labelled PricewaterhouseCoopers' Review Approach.

A review does not constitute an audit and consequently we do not express an audit opinion on this matter.

Based on our review, nothing has come to our attention that causes us to believe that for the settlement period of February, 2009 the settlement system and related processes were not operating, in all material respects, in accordance with section 7.2.5 and section(s) 7.4 - 7.15 of Chapter 7 of the Market Rules inclusive of the interpretations made by the NBSO as included in the accompanying description.



PricewaterhouseCoopers LLP.

Chartered Accountants

December 15, 2009

Calgary, Alberta

Management Interpretations of Chapter 7 of the Market Rules

Inputs to Settlement:

The review of the operation and application of the settlement and the related processes and procedures, addresses the mathematical calculations relating to settlement and the NBSO's creation of customer settlement statements. The completeness and accuracy of the inputs are not included in the scope of the review. However, the review includes the proper use of the inputs where specified by the market rules.

Wind Farm Settlements

In the market design for the New Brunswick Electricity Market, the term redispatch is the difference between the total hourly generation production for a given facility (i.e. as determined by the sum of all relevant balanced schedules) and the system operator's expectation of production from that facility (i.e. the dispatch instruction). Under the original - and current - market rules, the settlement for redispatch is at the relevant bid price. In the case of a positive redispatch, the supplier is credited for the redispatch quantity at the respective bid price. In the case of a negative redispatch, the supplier is charged for the redispatch quantity at the redispatch price.

In the case of a wind farm, the difference between the dispatch instruction and the sum of the relevant balanced schedules simply represents the difference in forecasts between that which is used in the creation of the optimized dispatch, and that which is used in the creation of the balanced schedules. These two forecast values may be different due to differences in (i) the approach used, (ii) data availability, and (iii) timing. Additionally, in normal circumstances it is desirable that the wind farm produce at its maximum capability rather than in response to a system operator expectation of production from that facility. Thus redispatch bid prices are of little relevance to system optimization.

As a consequence, NBSO has decided, in consultation with the Market Advisory Committee, to settle the difference between the hourly dispatch instruction and the sum of the relevant balanced schedules at the Final Hourly Marginal Cost. The relevant detailed market rule changes are under development, but wind farm "redispatch" is already being settled at FHMC in accordance with NBSO's commitment to the Market Advisory Committee.

Schedule 3, 5 and 6 Transmission Services

New load is exempt from any CBAS charges since the obligation is set based on the average 12 month demand in the previous calendar year. This definition of the obligation went into effect on April 1, 2008 as noted in Component 9a of the document "Straw man Model for the Alignment of Capacity-Based Ancillary Services (CBAS) Rates, Obligations, Revenues and Expenses" following consultation with stakeholders.

Over Commitment in FHBS

In instances where a unit is either over-scheduled or has metering in excess of its maximum offer, NBSO uses the FHMC for the hour to settle the unit. Energy imbalance is also settled at FHMC. The FHMC is deemed to be a fair value for this settlement as these deviations are closely related to energy imbalance.

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7.2 Collection, Recording, Validation and Adjustment of Metering Data

7.2.1 The SO shall perform the following activities for each Delivery Point and each Embedded Facility that has an interval meter with remote polling capability:

- a) on each Business Day, poll the meter and record the raw metering data in the Metering Database;
- b) on each Business Day, review the raw metering data with a view to identifying any discrepancies that could indicate failure of the metering equipment;
- c) on each Business Day, adjust the raw metering data to account for losses between the location of the metering installation and the applicable Delivery Point;
- d) on each Business Day, totalize the metering data from all interval metering installations located at the same Delivery Point; and
- e) by the third Business Day of each month, complete any error correction, substitution of metering data or other adjustment for the preceding month that may be required under section 7.3 other than in respect of disputes that remain outstanding at that time.

7.2.2 The SO shall perform the following activities for each Delivery Point and each Embedded Facility that has an interval meter without remote polling capability:

- a) on or between the first day of each month and the first Business Day of such month, read the interval meter and record the raw metering data in the Metering Database; and
- b) perform the activities referred to in sections 7.2.1(b) to 7.2.1(e) in respect of the interval metering data.

7.2.3 The SO shall perform the following activities for each Delivery Point associated with a Generation Facility, including an Embedded Generation Facility, that has a meter other than an interval meter and for each Delivery Point associated with a Load Facility that does not have an interval meter but that provides real-time data to the SO's SCADA system:

- a) on each Business Day, record in the Metering Database the provisional interval metering data derived from real-time monitoring of the SO-controlled Grid and certain Facilities through the SO's SCADA system;
- b) on each Business Day, review the provisional interval metering data with a view to identifying any discrepancies that could indicate failure of the monitoring equipment;
- c) on each Business Day, adjust the provisional interval metering data to account for losses between the location of the metering installation and the applicable Delivery Point;
- d) at 24:00 on the last day of each month, read the cumulative energy meters for each such Facility;
- e) on the first Business Day of each month, record the raw cumulative energy metering data in the Metering Database and review such raw cumulative energy metering data with a view to identifying any discrepancies that could indicate failure of the metering equipment;
- f) on the first Business Day of each month, make any necessary adjustment to the raw cumulative energy metering data to account for any discrepancy that might arise in the event of a material time difference between the time of reading of the meter under section 7.2.3(d) and 24:00;

- g) on the first Business Day of each month, adjust the raw cumulative energy metering data to account for losses between the location of the metering installation and the applicable Delivery Point;
 - h) by the second Business Day of each month, correct the provisional interval metering data referred to in section 7.2.3(c) to reflect the corresponding cumulative energy quantity for the preceding month;
 - i) by the second Business Day of each month, totalize the metering data from all metering installations located at the same Delivery Point; and
 - j) by the third Business Day of each month, complete any error correction, substitution of metering data or other adjustment for the preceding month that may be required under section 7.3 other than in respect of disputes that remain outstanding at that time.
- 7.2.4 The SO shall perform the following activities for each Delivery Point that is not subject to any one of sections 7.2.1 to 7.2.3:
- a) on one of the last three days of each month or, if the last two days of a month are Business Days, on one of such Business Days, read the cumulative energy, peak energy demand and peak kVA values from each meter;
 - b) by the first Business Day of each month, record the raw metering data in the Metering Database and review the raw metering data with a view to identifying any discrepancies that could indicate failure of the metering equipment;
 - c) by the second Business Day of the month, adjust the raw metering data to account for losses between the location of the metering installation and the applicable Delivery Point;
 - d) by the second Business Day of each month, totalize the metering data from metering installations located at the same Delivery Point;

- e) by the third Business Day of each month, complete any error correction, substitution of metering data or other adjustment for the preceding month that may be required under section 7.3 other than in respect of disputes that remain outstanding at that time; and
- f) by the fourth Business Day of each month, determine the imputed hourly metering data for each hour of the preceding month for each Delivery Point in accordance with section 7.2.5.

7.2.5 The imputed hourly metering data for a Delivery Point referred to in section 7.2.4(f) shall be the total monthly energy quantity determined for that Delivery Point, as adjusted, totalized and corrected in accordance with sections 7.2.4(a) to 7.2.4(e), multiplied by the net non-interval-metered load shape value for the applicable hour. The net non-interval-metered load shape value for an hour shall be the net non-interval-metered hourly load divided by the total monthly net non-interval-metered load as determined by the SO under section 7.2.6.

7.2.6 For the purposes of section 7.2.5:

- a) the net non-interval-metered hourly load for any hour shall be the difference between the total injections into and interval-metered withdrawals from the SO-controlled Grid in that hour, determined on the basis of the interval metering data referred to in sections 7.2.1 to 7.2.3; and
- b) the total monthly net non-interval-metered load for any month shall be the aggregate of the net hourly non-interval-metered loads determined under section 7.2.6(a) for each hour in that month.

7.2.7 Without limiting the generality of section 1.6.4, the SO may arrange for a third party to conduct some or all of the meter reading activities referred to in sections 7.2.1 to 7.2.4. Where the SO makes such arrangements, the SO shall:

7.3.12 Subject to section 7.3.13, when load is transferred between Delivery Points, the Market Participants involved may notify the SO in advance of the transfer and request that the transfer be recognized for purposes of the calculation of the Demand associated with those Delivery Points. Such notice shall identify the Delivery Points that may be affected by the transfer. Upon receipt of such notice, the SO shall read and reset, or arrange for the reading and resetting, of all of the demand meters at the Delivery Points so identified, which activities shall be coordinated with the timing of the load transfer. Where the demand meter is an interval meter, the SO shall identify and read the peak Demand since the previous occasion on which the peak Demand was identified and read at all identified Delivery Points. Such peak Demand readings shall constitute a set of readings, and separate sets shall be established by the SO in respect of any further load transfer notices received by the SO in respect of the same Delivery Point in the same Settlement Period as well as in respect of the meter readings conducted at the end of a Settlement Period. The peak Demand for a Settlement Period for each Delivery Point associated with a load transfer notice shall be the reading in the set of readings for the Settlement Period that has the highest total sum of all Demand readings in the set.

7.3.13 Section 7.3.12 shall not:

- a) apply unless the application of that section is permitted by the Transmission Tariff; and
- b) preclude the making of any other applicable adjustments to metering data provided for in section 7.2 or this section 7.3.

7.4 Access to, Ownership and Release of Metering Data

7.4.1 Metering data in respect of each Interconnection and each Delivery Point shall be owned by the SO. Metering data in respect of each Embedded Facility shall be owned by the Embedded Facility's Host.

7.4.2 The SO shall make all metering data in the Metering Database pertaining to a Delivery Point available to each person entitled to have access thereto under

section 7.4.3 at each stage of collection, adjustment, totalization and correction.
Such metering data shall be made available:

- a) in such manner as to ensure that access is limited to persons entitled to have access under section 7.4.3; and
- b) in an electronic form that is capable of being downloaded.

7.4.3 Persons shall have access to metering data in accordance with section 7.4.2 as follows:

- a) in respect of the Delivery Point for an Interconnection, the applicable Transmitter and the operator of any applicable interconnected transmission system;
- b) in respect of all Delivery Points, the applicable Transmitter;
- c) in respect of a Facility associated with a Delivery Point, the Market Participant for that Facility;
- d) in respect of an Embedded Facility, the Embedded Facility's Host; and
- e) to the extent that the systems of the SO can accommodate such access, to the agent of any person referred to in any one of sections 7.4.3(a) to 7.4.3(d) identified to the SO by the person as its agent.

7.4A Treatment of Bid-Based Demand Response

7.4A.1 The SO shall, in performing settlement with respect to Bid-Based Demand Response:

- a) measure provision of Bid-Based Demand Response as the actual hourly Demand versus what the hourly Demand would have been absent demand response to a Dispatch Instruction issued by the SO;

- b) establish a Baseline Demand to be used in the settlement of Bid-Based Demand Response as the hourly Demand that would have occurred absent Demand Response relative to a Dispatch Instruction issued by the SO;
- c) not consider the portion of Demand for a given Facility deemed to be Interruptible Load that was, or would have been, interrupted in accordance with Chapter 6 to have provided Bid-Based Demand Response; and
- d) minimize the impact of the Bid-Based Demand Response on the Market Participant for the Facility if that entity is not also the Market Participant for Bid-Base Demand Response with respect to that Facility.

7.4A.2 By the fourth Business Day of each month, the SO will determine Settlement Amounts for each Market Participant in respect of Bid-Based Demand Response for the preceding month in accordance with this section 7.4. The SO will calculate Settlement Amounts on an hourly basis for all hours in which it issued a Dispatch Instruction.

7.4A.3 By default, the Baseline Demand for the settlement of Bid-Based Demand Response shall be established as the highest 10 of the 11 preceding weekdays. The SO may approve other methodologies, by exception, only where such methodology is superior to the default methodology with respect to that Facility due to its unique characteristics;

7.4A.4 The settlement with the Market Participant for Bid-Based Demand Response shall be composed of the following:

(a) a Redispatch Settlement Credit or RSC payable to or by a Market Participant calculated as per section 7.6.8(b), whereby the costs of operating in accordance with the FHBS will typically be zero thus resulting in an RSC equal to the Quantity of energy dispatched multiplied by the Bid-Based Demand Response price(s) bid for that energy;

(b) an Imbalance Quantity – Demand or IQD which shall be the quantity of any actual variance in the hourly Demand of the facility from the Dispatched Demand, where the Dispatched Demand is the Baseline Demand less the Dispatch Instruction for Bid-Based Demand Response.

The SO shall charge or credit, as the case may be, each Bid-Based Demand Response Market Participant which has an IQD with respect to its Bid-Based Demand Response Capability, in a given hour at the FHMC for each such hour and each Bid-Based Demand Response Capability.

7.4A.5 If the Market Participant for the Facility is the standard service supplier, then adjustments shall be made in the SO settlement with the standard service supplier in respect of the Facility or Facilities associated with the Bid-Based Demand Response as follows:

(a) the hourly metering data for the purposes of energy variance settlement shall be an adjusted amount equal to the Baseline Demand less the Dispatch Instruction for the Bid-Based Demand hourly energy;

(b) the Demand for the purposes of all other billing shall not be adjusted on account of Bid-Based Demand Response events or Dispatch Instructions.

7.4A.6 In the event of an interruption of Interruptible Load, or a general interruption of standard service interruptible load classes that coincides or overlaps with dispatch of Bid-Based Demand Response load, the SO shall adjust the settlement by:

(a) annulling the Bid-Based Demand Dispatch if the firm load is less than the Dispatched Demand; or otherwise

(b) reducing the baseline to the firm load, and setting the Dispatch Instruction such that the Dispatched Demand is no less than what it would have been absent the interruption.

7.5 Settlement for Transmission Service Charges

7.5.1 By the fourth Business Day of each month, the SO shall determine Settlement Amounts for each Market Participant and each Transmitter in respect of Transmission Service Charges for the preceding month in accordance with this section 7.5.

7.5.2 Market Participant Settlement Amounts for Point-to-Point Service charges shall be determined by the SO for each Market Participant on the basis of transmission reservations made by the Market Participant, the rates for Point-to-Point Service set out in the Transmission Tariff and any discounts applicable to the Market Participant as may have been notified to the SO by the applicable Transmitter. In the event that withdrawals by the Market Participant's Facilities exceed the amount contemplated in the transmission reservations, the SO shall determine additional Settlement Amounts for Point-to-Point Service charges in accordance with the Transmission Tariff.

7.5.3 Market Participant Settlement Amounts for Network Integration Service charges shall be determined by the SO for each Market Participant in respect of each applicable Delivery Point on the basis of the metering data associated with that Delivery Point and the rate set out in the Transmission Tariff.

7.5.4 Except as noted in section 7.10.3, all Transmission Service Charges charged by the SO to Market Participants shall be credited by the SO to each applicable Transmitter that is subject to the Transmission Tariff. Transmission Service Charges shall be allocated by the SO amongst Transmitters based on their respective revenue requirements as approved by the PUB as the basis for the Transmission Tariff.

7.6 Settlement for Ancillary Service Procurement, Congestion Management Re-dispatch and Energy Variances

7.6.1 By the fourth Business Day of each month, the SO shall determine Settlement Amounts:

- a) payable to Market Participants for Ancillary Services procured by the SO;
and
- b) payable to or by Market Participants for re-dispatch by the SO,

in the preceding month in accordance with this section 7.6.

7.6.2 Settlement Amounts payable to each applicable Market Participant for Ancillary Services shall be determined by the SO in accordance with sections 7.6.3 and 7.6.4 on the basis of the payment terms contained in the Ancillary Services contract with that Market Participant and, where applicable, the Ancillary Services scheduled or dispatched under that Ancillary Services contract.

7.6.3 The Settlement Amount for Black Start Capability Service shall be a fixed monthly amount that reflects the fixed monthly amount and contracted quantities identified in the applicable Ancillary Services contract, having regard to any provisions of such contract with respect to Outages or availability of the Facility.

7.6.4 The Settlement Amount for each Ancillary Service other than Black Start Capability Service shall be a variable monthly amount that reflects the rate provided for in the applicable Ancillary Services contract and the quantities of each Ancillary Service scheduled from each Facility in each applicable Final Hourly Commitment Schedule or otherwise dispatched from that Facility.

7.6.5 The SO shall determine the total re-dispatch costs associated with Ancillary Services and congestion management in accordance with section 7.6.6 on the basis of Day Ahead data. The SO shall determine the rate applicable to energy variances in accordance with section 7.6.7 on the basis of hour ahead data. The SO shall determine the Settlement Amounts associated with the energy re-

dispatch of individual Generation Facilities in accordance with section 7.6.8, and shall determine the Residual Re-dispatch Cost in accordance with section 7.6.9, on the basis of hour ahead and real time data. For all such determinations, the costs or re-dispatch costs of a schedule shall reflect the start-up costs referred to in section 6.5.3(a), the Minimum Run Costs and the incremental and decremental energy costs reflected in the Final Day Ahead Dispatch Data or the Final Hourly Dispatch Data, as the case may be. Re-dispatch costs shall exclude the variable amount based on the rate set forth in the applicable Ancillary Services contract referred to in section 7.6.4.

7.6.6 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 schedule, referred to as “DAEOUS”, using data identical to that used in determining the Final Day Ahead Commitment Schedule under section 6.9 except that all scheduled quantities of Ancillary Services shall be set to equal only those quantities scheduled to be self-supplied, and all Transmission constraints within the Province shall be ignored;
- b) the SO shall determine an optimized Day Ahead, energy and Ancillary Services unconstrained schedule, referred to as “DAEAUS”, using data identical to that used in determining the Final Day Ahead Commitment Schedule under section 6.9 except that all Transmission constraints within the Province shall be ignored;
- c) the SO shall calculate the total cost for each corresponding Dispatch Day associated with each of the following schedules:
 - i. the DAEOUS, for which the cost shall be designated as “DAEOUC” and which shall be calculated in accordance with section 7.6.6(f), where applicable;

- ii. the DAEAUS, for which the cost shall be designated as “DAEAUC” and which shall be calculated in accordance with section 7.6.6(f), where applicable; and
 - iii. the Final Day Ahead Commitment Schedule, for which the cost shall be designated as “FDACC” and which shall be calculated in accordance with section 7.6.6(f), where applicable;
- d) the SO shall calculate the total Ancillary Service Re-dispatch Cost or ASRC, which shall be DAEAUC minus DAEOUC;
- e) the SO shall calculate the total Congestion Management Cost or CMC, which shall be FDACC minus DAEAUC; and
- f) 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 defined by either $Q(0)$ to $Q(n_{max})$ or, if applicable, by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time, then the values of each of DAEOUC, 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 up to either $Q(0)$ or, if applicable, to the load profile determined by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time.
- 7.6.7 The SO shall determine the Final Hourly Marginal Cost or FHMC as the marginal cost saving to the system that would have been achieved if system primary demand had been reduced by 1 MW in the Final Hourly Commitment Schedule referred to in section 6.10.12.
- 7.6.8 The SO shall determine real-time energy re-dispatch Settlement Amounts and associated costs as follows:

- a) the SO shall calculate the total dispatch deviation of each Facility for each hour from the Final Hourly Balanced Schedule or FHBS referred to in section 6.10.8. This total dispatch deviation shall comprise:
 - i. the energy quantity for that Facility provided for in the FHCS minus the energy quantity for that Facility provided for in the FHBS;
 - ii. minus the reduction in energy quantities arising from curtailment of a transaction underlying a Balanced Schedule as a result of transmission loading relief effected in accordance with NERC standards and practices;
 - iii. plus any variance between the total of the energy dispatched from the Facility by the SO in each hour relative to the dispatch provided for in the FHCS, including on account of activation for Operating Reserve Service, Load Following Service or Automatic Generation Control Service or activation of an SPS to which section 4.6.4(b) applies;

For the purposes of this calculation, any Forced Outage shall be treated as a deviation in accordance with section 7.6.11;

- b) the SO shall calculate the Re-dispatch Settlement Credit or RSC, which may if negative be a debit, payable to or by a Market Participant in respect of energy re-dispatch from a Facility (including Bid-Based Demand Response) for each Dispatch Day as the Facility's costs in operating in accordance with its Dispatch Instructions minus the Facility's costs in operating in accordance with the FHBS, determined in accordance with section 7.6.8(c) if applicable. For this purpose, a Facility's costs shall be the start-up costs, Minimum Run Costs and incremental energy costs as identified in the Final Hourly Dispatch Data for the Facility for each hour of the Dispatch Day. The incremental energy costs per MWh for energy scheduled or dispatched from a Facility

during the Facility's ramp-up and ramp-down phases shall be priced at the Facility's MRC divided by the Facility's MRQ. Any actual start-up costs and Minimum Run Costs incurred by a Market Participant in complying with a Commitment Schedule prior to that Commitment Schedule being revised or superseded shall be included in the Facility's costs in operating in accordance with its Dispatch Instructions;

- c) where the FHBS schedules a Generation Facility to have a total output that is not zero and lies outside the possible range defined by either $Q(0)$ to $Q(n_{\max})$ or, if applicable, by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time, then the value of RSC shall be calculated on the basis that the FHBS requires the Generation Facility to be operating and using a re-dispatch price of zero for all energy up to either $Q(0)$ or, if applicable, to the load profile determined by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time.
 - d) the SO shall calculate the Total Re-dispatch Cost or TRC, as the net total of the RSC for all Facilities in each day, and which equates to the difference in total cost between the FHBS and the real-time dispatch schedule; and
- 7.6.9 The SO shall calculate the Residual Re-dispatch Cost or RRC for each day as the total of all TRC for that day minus each of ASRC and CMC. The SO shall include the RRC in the Residual Monthly Costs in accordance with section 7.8.
- 7.6.10 Settlement Amounts and associated costs associated with schedule rounding errors and with energy variance (imbalance) shall be determined by the SO for each applicable Market Participant in accordance with sections 7.6.11 to 7.6.13.
- 7.6.11 The SO shall determine Settlement Amounts for actual energy 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 or 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, as the case may be, each Market Participant whose Generation Facility has an IQG in a given hour at the FHMC for each such hour and Generation Facility;
- 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 or 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, as the case may be, each Market Participant whose Load Facility has an IQL in a given hour at the hourly FHMC for that hour, multiplied by the applicable loss factor specified in the Transmission Tariff; and
- e) variances in the import or export flows on Radial Interconnections, including variances associated with External Dispatchable Facilities, 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.

7.6.12 The SO shall determine Settlement Amounts for cumulative energy variances as follows:

- a) the SO shall accumulate the energy variance quantities IQG and IQL to establish on-peak and off-peak cumulative variance quantities for each Market Participant for each hour; and

- b) if, at the end of any hour, the on-peak or off-peak cumulative variance quantities determined under section 7.6.12(a) for a Market Participant are less than -20% of, or greater than 20% of, the average quantity scheduled over the on-peak or off-peak hours in the month in which energy is scheduled, the deficiency or excess shall be settled at the relevant rate prescribed in the Transmission Tariff, and the variance thus settled shall be excluded from the further accumulation of energy variance quantities under section 7.6.12.(a).

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

$Q(\text{injection}) - [Q(\text{withdrawal}) * (1 + \text{transmission loss factor})]$, rounded to the nearest kWh

The SO shall determine the Schedule Rounding Amount or SRA due in each hour to each Market Participant as the schedule rounding error determined in accordance with this section 7.6.13 multiplied by FHMC for each of the Market Participant's Balanced Schedules.

7.6.14 The net amount payable to a Market Participant under section 7.6.11(b) or 7.6.11(d) in respect of each of the Market Participant's Facilities or Bid-Based Demand Response capabilities shall be the Actual Energy Variance Settlement Credit or "AEVSC" (or "AEVSCG" for Generation Facilities, "AEVSCD" for Bid-Based Demand Response Capabilities, and "AEVSCL" for Load Facilities, respectively) for that Market Participant. The Net Imbalance Cost or "NIC" for the Settlement Period shall be the total net cost to the SO of all AEVSCs plus the net cumulative energy variance amount calculated in accordance with section 7.6.12(b) and the total cost of all SRAs.

7.6.15 The SO shall include the NIC in the Residual Monthly Costs in accordance with section 7.8.

7.7 Determination of Monthly Ancillary Services Re-dispatch Costs

7.7.1 By the fourth Business Day of each month, the SO shall determine the total re-dispatch cost associated with each Ancillary Service in the preceding month in accordance with this section 7.7.

7.7.2 The SO shall allocate the ASRC determined in accordance with section 7.6.6 to individual Ancillary Services as follows:

- a) the SO shall determine the total quantity, in MWh, of each Ancillary Service scheduled in the FDACS, other than as a self-supplied Ancillary Service, to be provided on the corresponding Dispatch Day and shall determine the equivalent quantity of Load Following Service for each other such Ancillary Service as follows:
 - i. each MWh of AGC Service 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 associated with each Ancillary Service.

7.8 Determination of Residual Monthly Costs

7.8.1 By the fourth Business Day of each month, the SO shall determine the total Residual Monthly Costs or RMC for the preceding month as the aggregate over the month of amounts reflecting the costs, debits or credits relating to the following:

- a) penalties for deficiencies in Capacity Obligations referred to in section 5.4.11(a);
- b) the costs incurred by the SO in procuring replacement capacity commitments referred to in section 5.4.11(b);
- c) penalties for deficiencies in the performance of Capacity Resources referred to in section 5.4.13;
- d) costs incurred by the SO in paying compensation under section 5.7.7 or 5.7.8;
- e) penalties for being in an unauthorized Cold Condition referred to in section 6.4.1A;
- f) penalties for deficiencies in performance by Capacity Resources referred to in section 6.7.6A;
- g) penalties for deficiencies in performance by Interruptible Load Facilities referred to in section 6.7.9;
- h) the purchase and sale of Emergency Energy referred to in sections 6.17.1(c) and 6.17.3;
- i) the fixed monthly amounts associated with Black Start Capability Service as determined under section 7.6.3;

- j) the RRC as determined under section 7.6.9;
 - k) the NIC as determined under section 7.6.14;
 - l) penalties included in miscellaneous charges referred to in section 7.10.2;
 - m) costs relating to the resolution of disputes referred to in sections 7.3.11 and 7.11.7;
 - n) the net cost to the SO of defaults in payment by Market Participants referred to in sections 7.14.3(b) and 7.14.4(b);
 - o) net recoveries by the SO in respect of defaults in payment by Market Participants referred to in section 7.14.5;
 - p) the costs incurred by the SO in collecting default amounts referred to in section 7.14.6;
 - q) any amount paid to or by the SO on account of interest under the Market Rules; and
 - r) other recoveries and costs of a similar nature to the above items (a) to (q).
- 7.8.2 Residual Monthly Costs shall be recovered by the SO from Market Participants through Residual Uplift in accordance with section 7.9.5.

7.9 Charge Determinants and Charge Rates for each Ancillary Service, Congestion Management Uplift and Residual Uplift

7.9.1 The SO shall determine the charge determinant quantity for each Ancillary Service for each Delivery Point in respect of each transaction using Network Integration Service and Point-to-Point Service based on:

- a) metering data;

- b) in respect of the provision of Scheduling, System Control and Dispatch Service and Reactive Power/Voltage Support Service associated with transactions using Point-to-Point Service, the transmission reservations;
 - c) the self-supply of Ancillary Services under section 6.2; and.
 - d) any applicable special adjustment determined in accordance with section 7.9.9.
- 7.9.2 The SO shall determine the charge determinant quantity for the Congestion Management Uplift for each Delivery Point in respect of each transaction using Network Integration Service based on metering data, on the basis of use of the system coincident with system peak demand as provided for in the Transmission Tariff..
- 7.9.3 For the Congestion Management Uplift, the rate per equivalent coincident peak use of Network Integration Service shall be set equal to the CMC for the Settlement Period, determined in accordance with section 7.6.6, divided by the charge determinant quantity as determined in accordance with section 7.9.2.
- 7.9.4 The SO shall determine the charge determinant quantity for Residual Uplift for each Delivery Point in respect of each transaction using Network Integration Service based on metering data and in respect of each transaction using Point-to-Point Service based on transmission reservations, in each case on the same basis as it determines the charge determinant quantity for Scheduling, System Control and Dispatch Service provided for in the Transmission Tariff. The SO shall determine the total equivalent charge determinant quantity for Residual Uplift using the equivalence ratios for Scheduling, System Control and Dispatch Service set out in the Transmission Tariff.
- 7.9.5 For the Residual Uplift, the rate per equivalent non-coincident peak use of Network Integration Service shall be set equal to the RMC for the Settlement Period, determined in accordance with section 7.8, divided by the total equivalent charge determinant quantity determined in accordance with section 7.9.4.

- 7.9.6 By the fourth Business Day of each month, the SO shall determine the Ancillary Service re-dispatch Settlement Amounts to be debited to each Market Participant in respect of each of Automatic Generation Control Service, Load Following Service and all three classes of Operating Reserve Service. Each such Settlement Amount shall be determined on the basis of the non-coincident peak demand at each of the Market Participant's Delivery Points, net of any demand in respect of which the Market Participant has self-supplied the Ancillary Service in accordance with section 6.2. The re-dispatch rate for each Ancillary Service shall be determined in accordance with sections 7.9.7 and 7.9.8.
- 7.9.7 The SO shall determine the total charge determinant quantity for each Ancillary Service referred to in section 7.9.6 for each Settlement Period on the basis of the non-coincident peak demand at each Delivery Point. Such demand shall be net of any demand in respect of which any applicable Market Participant has self-supplied the Ancillary Service in accordance with section 6.2.
- 7.9.8 For each Ancillary Service referred to in section 7.9.6, the re-dispatch rate per MW of non-coincident peak demand shall be set equal to the total re-dispatch cost for that Ancillary Service for the Settlement Period, as determined in accordance with section 7.7 and subject to any applicable special adjustment determined in accordance with section 7.9.9, divided by the total charge determinant quantity as determined in accordance with section 7.9.7.
- 7.9.9 For each day on which one or more Market Participants is responsible for incremental Operating Reserve under section 6.2.1, the following provisions shall apply:
- a) the SO shall recalculate the DAEAUC by excluding the requirement for such incremental Operating Reserve, which recalculated DAEAUC shall be referred to as DAEAUC*;
 - b) the SO shall calculate the incremental re-dispatch cost attributable to such incremental Operating Reserve as DAEAUC minus DAEAUC*;

- c) the SO shall allocate the incremental re-dispatch cost referred to in section 7.9.9(b) to the transactions that triggered the incremental Operating Reserve requirement in accordance with section 7.9.9(d) and shall deduct the same amount from the re-dispatch cost used in the determination referred to in section 7.9.6;
- d) the SO shall allocate the incremental re-dispatch cost referred to in section 7.9.9(b) amongst the Market Participants responsible for the transactions that triggered the incremental Operating Reserve requirement as a debit in proportion to each such Market Participant's contribution to the total requirement of each class of Operating Reserve after accounting for any self-supply arrangements made by each Market Participant and accepted by the SO; and
- e) the SO shall determine any other incremental costs associated with such incremental Operating Reserve requirement, shall allocate such costs in accordance with section 7.9.9(d) and shall record such costs as a credit to the applicable variance account referred to in section 7.12.1.

7.10 Miscellaneous Charges

7.10.1 By the fourth Business day of each month, the SO shall determine the miscellaneous charges, if any, applicable to each Market Participant and Transmitter for the preceding month. Miscellaneous charges may be a credit or a debit.

7.10.2 Miscellaneous charges shall include any penalties or other charges to which a Market Participant or Transmitter may be subject under the Market Rules, an Ancillary Services contract, an Interruptible Load contract or an Operating Agreement, that are collected other than on account of costs incurred by the SO under the Market Rules or on behalf of a Transmitter and that are not otherwise specifically provided for in this Chapter other than this section 7.10. The amount of any such penalty or charge shall, when paid, be credited to the Residual Monthly Costs.

7.10.3 Miscellaneous charges may include charges to be collected by the SO on behalf of a Transmitter in respect of power factor penalties, metering activities and non-capital support charges as determined in accordance with the Transmission Tariff or Connection Agreements. The amount of any such charges shall, when paid, be credited to the applicable Transmitter.

7.11 Settlement Statements

7.11.1 By the fifth Business Day of each month, the SO shall prepare and make available a Settlement Statement to each Market Participant and to each Transmitter for the preceding month. The Settlement Statement for each Market Participant and for each Transmitter shall be made available by web-based communications in such manner as to ensure that access is limited to that Market Participant or Transmitter. The SO may delay issuance of a Settlement Statement by up to two Business Days and/or may use estimated quantities and amounts subject to adjustment in the following Settlement Statement, if and to the extent that the SO is prevented from issuing a Settlement Statement in accordance with otherwise applicable requirements due to a failure of its systems or processes.

7.11.2 Each Settlement Statement shall set out all debits and credits arising in the preceding month, each charge determinant quantity, and the rate applicable to each as determined in accordance with this Chapter, and other relevant information such as the hour in which non-coincident peak demand was recorded in cases where interval metering data is available.

7.11.3 The credits and debits to be included in each Settlement Statement shall include, as may be applicable to a given Market Participant or Transmitter:

- a) Transmission Service Charge credits allocated to a Transmitter under section 7.5.4;
- b) amounts allocated to a Transmitter under any one of sections 7.14.4(a), 7.14.5 or 7.14.6;

- c) debits allocated to a Market Participant for Point-to-Point Service under section 7.5.2;
- d) debits allocated to a Market Participant for Network Integration Service under section 7.5.3;
- e) the Re-dispatch Settlement Credit (which may be a debit) determined in accordance with section 7.6.8(b);
- f) the Actual Energy Variance Settlement Credit determined in accordance with section 7.6.14 and the cumulative energy variance Settlement Amount determined in accordance with section 7.6.12;
- g) the Schedule Rounding Amount determined in accordance with section 7.6.13;
- h) Scheduling, System Control and Dispatch Service in respect of each of:
 - i. the amount calculated using the fixed rate referred to in the Transmission Tariff, subject to any applicable discounts permitted by the Transmission Tariff;
 - ii. the amount calculated using the rate for Congestion Management Uplift as determined under section 7.9.3; and
 - iii. the amount calculated using the rate for Residual Uplift as determined under section 7.9.5;
- i) Reactive Power/Voltage Support Service in respect of the amount calculated using the fixed rate referred to in the Transmission Tariff, subject to any applicable discounts permitted by the Transmission Tariff;
- j) Load Following Service and Automatic Generation Control Service in respect of both:

- i. the amount calculated using the fixed rate referred to in the Transmission Tariff, subject to any applicable discounts permitted by the Transmission Tariff; and
 - ii. the amounts calculated using the rates for re-dispatch in respect of Load Following Service and Automatic Generation Control Service as determined under section 7.9.8;
- k) 10-minute spinning Operating Reserve Service, in respect of each of:
 - i. the amount calculated using the fixed rate referred to in the Transmission Tariff, subject to any applicable discounts permitted by the Transmission Tariff ;
 - ii. the amount calculated using the rate for re-dispatch as determined under section 7.9.8; and
 - iii. the incremental Operating Reserve adjustment referred to in section 7.9.9;
- l) 10-minute non-spinning Operating Reserve Service in respect of each of:
 - i. the amount calculated using the fixed rate referred to the Transmission Tariff, subject to any applicable discounts permitted by the Transmission Tariff;
 - ii. the amount calculated using the rate for re-dispatch as determined under section 7.9.8; and
 - iii. the incremental Operating Reserve adjustment referred to in section 7.9.9;
- m) 30 minute Operating Reserve Service in respect of both:

- i. the amount calculated using the fixed rate referred to in the Transmission Tariff, subject to any applicable discounts permitted by the Transmission Tariff; and
- ii. the amount calculated using the rate for re-dispatch as determined under section 7.9.8;
- n) the miscellaneous charges referred to in section 7.10;
- o) adjustments arising in respect of matters occurring in previous Settlement Periods referred to in sections 7.3.11, 7.11.1, 7.11.7 and 7.13.1; and
- p) Settlement Amounts referred to in section 7.6.2 in respect of Ancillary Services provided to the SO.

7.11.4 A Market Participant or Transmitter may, no later than the later of the last Business Day of the month following the month to which a Settlement Statement applies and 10 Business Days after the Settlement Statement was made available to it under section 7.11.1, notify the SO of any inquiry or dispute relating to such Settlement Statement. The SO shall promptly respond to the inquiry or attempt to resolve the dispute with the Market Participant or Transmitter. Where the Market Participant or Transmitter is not satisfied with the response provided or the resolution of the dispute, the Market Participant or Transmitter may, within ten Business Days of the date of receipt of the last communication from the SO in respect of the inquiry or dispute, initiate the dispute resolution process referred to in section 3.6. Any invoice amount shall be due and payable at the time specified for payment under the Market Rules notwithstanding the initiation of a dispute in respect of a corresponding Settlement Statement under this section 7.11.4 or section 7.11.6.

7.11.5 Any Settlement Statement or item thereon in respect of which no notice of inquiry or dispute has been submitted within the time referred to in section 7.11.4 shall be final and, subject to section 7.11.6, shall not thereafter be subject to dispute.

7.11.6 A Settlement Statement or an item thereon may be the subject of dispute notwithstanding the expiry of the deadline referred to in section 7.11.4 in cases where an error or fraud is discovered thereafter. Such dispute cannot be commenced by a Market Participant or Transmitter unless the Market Participant or Transmitter demonstrates to the satisfaction of the SO that the error or fraud could not, by the exercise of due diligence, have been detected by the Market Participant or Transmitter prior to the expiry of such deadline. Notice of a dispute referred to in this section 7.11.6 shall be given to the other party promptly following discovery of the error or fraud.

7.11.7 Where the resolution of an inquiry or dispute pertaining to a Settlement Statement results in an amount owing to or by a Market Participant or Transmitter, that amount shall be included as a miscellaneous charge credit or debit in the next available Settlement Statement for that Market Participant or Transmitter. Where resolution of such an inquiry or dispute also affects the Settlement Amounts of other Market Participants or a Transmitter, the SO shall reflect any adjustment in the calculation of the Residual Monthly Costs on the next available Settlement Statements.

7.11.8 Any amounts payable to or by a Market Participant as a result of the resolution of an inquiry or dispute shall bear interest, accrued on a daily basis, at the base lending rate that the bank where the SO's Settlement accounts are maintained charges for commercial loans to its best and most creditworthy commercial customers where the amount is paid later than the date for payment of the Settlement Statement to which the inquiry or dispute relates.

7.11.9 Nothing in sections 7.11.4 to 7.11.8 shall be construed as:

- a) requiring that notice be given of an inquiry or dispute in respect of which notice has been given under section 7.3.7 or 7.3.8; or
- b) extending the time set forth in section 7.3.7 for providing notice of a dispute pertaining to metering data.

7.12 Accounting for Variances

7.12.1 The SO shall maintain variance accounts to account for differences between the fixed costs of Black Start Capability Service and the variable cost components of all other Ancillary Services and the revenues based on the fixed rate for such Ancillary Services set forth in the Transmission Tariff, as applied to variable charge determinant quantities.

7.12.2 The SO shall monitor the variance accounts referred to in section 7.12.1, and Publish quarterly reports on such accounts. The SO Board shall, in circumstances where the application of the Transmission Tariff results in a material cumulative over-recovery of costs other than in respect of expected seasonal variance, and to the extent permitted by the Transmission Tariff, determine a discount to be applied to the fixed rates for an Ancillary Service referred to in section 7.12.1. Such discount may be applied for a fixed period or until further notice.

7.13 Invoicing and Payment

7.13.1 By the fifth Business Day of each month, the SO shall issue an invoice to each Market Participant and to each Transmitter for the preceding month. Such invoice shall summaries the credits and debits from the associated Settlement Statement. An invoice may be issued in electronic form to a Market Participant or Transmitter where the Market Participant or Transmitter has provided an address to the SO for such purpose. The SO may delay issuance of an invoice by up to 2 Business Days and/or may use estimated quantities and amounts subject to adjustment in the following Settlement Statement, if and to the extent that the SO is prevented from issuing an invoice in accordance with otherwise applicable requirements due to a failure of its systems or processes.

7.13.2 Such electronic funds transfer shall be completed no later than the close of banking business of the SO's bank on the 20th day of the month or, if not a Business Day, on the closest previous Business Day, as designated on the calendar referred to in section 7.1.2.

7.13.3. The SO shall pay to each applicable Market Participant and Transmitter the full amount of a net credit invoice within two Business Days after the date referred to in section 7.13.2.

7.13.4 Where a Market Participant, a Transmitter or the SO fails to make, in whole or in part, a payment on the date due for payment under the Market Rules, the outstanding amount shall bear interest, accrued on a daily basis, at the base lending rate that the bank where the SO's settlement accounts are maintained charges for commercial loans to its best and most creditworthy commercial customers plus 2 percent.

7.14 Payment Default

7.14.1 In the event that a Market Participant does not make full payment of an invoice by the date due for payment referred to in section 7.13.2, the SO may, without prejudice to any other remedy that may be available to the SO under the Market Rules or under Applicable Law, realize on any Credit Support provided by or on behalf of the Market Participant.

7.14.2 The SO may, in addition to the action referred to in section 7.14.1, take such other action as it considers prudent and reasonable in order to collect the total amount in default, and may take the available actions provided for in sections 2.7 and 2.8.

7.14.3 Any net default amount remaining unpaid on the date on which the Settlement Statements referred to in section 7.14.4 are issued shall, after adjustment in respect of any Harmonized Sales Tax, be allocated by the SO to each of the following categories:

- a) amounts collected on behalf of a Transmitter in respect of Transmission Service Charges and miscellaneous charges; and
- b) all other amounts.

Such allocation shall be effected on a proportional basis relative to the amount invoiced for each category of amount and the net default amount.

7.14.4 Settlement Statements issued in respect of the month in which the default in payment occurred shall reflect the following:

- a) any amount allocated to a Transmitter under section 7.14.3(a) shall be debited to the Transmitter; and
- b) any amount allocated to other amounts under section 7.14.3(b) shall be included as a debit to the Residual Monthly Costs.

7.14.5 Where, subsequent to the issuance of the Settlement Statements referred to in section 7.14.4, the SO recovers from the defaulting Market Participant some or all of the default amount not already accounted for in those Settlement Statements, including by means of realization on applicable Credit Support, the SO shall allocate such recovered amount net of any collection costs incurred by the SO in effecting collection. Sections 7.14.3 and 7.14.4 shall apply, with such modifications as the context may require, to the allocation of such recovered amount as between a Transmitter and the Residual Monthly Costs.

7.14.6 Where the SO incurs collection costs in respect of a default in payment and such default is not recovered, such collection costs shall be allocated by the SO. Sections 7.14.3 and 7.14.4 shall apply, with such modifications as the context may require, to the allocation of such collection costs.

7.15 Publication of Information and Audit

7.15.1 The SO shall Publish the following aggregated settlement-related information for each Settlement Period:

- a) total energy metering data pertaining to injections to the SO-controlled Grid by all Facilities located in New Brunswick for each hour;

- b) total energy metering data pertaining to withdrawals from the SO-controlled Grid by all Facilities located in New Brunswick for each hour;
- c) such other aggregated metering data as the SO considers appropriate;
- d) the total net energy production of each Generation Facility;
- e) total imports, by Interconnection, for each hour;
- f) total exports, by Interconnection, for each hour;
- g) total of each Ancillary Service procured for each hour;
- h) the ASRC for each day;
- i) the CMC for each day;
- j) the RRC for each day;
- k) the NIC for the Settlement Period;
- l) the total monthly charge determinant quantity for each Transmission Service Charge as specified in the Transmission Tariff and the total monthly charge determinant quantity for each Ancillary Services charge for the Settlement Period;
- m) the aggregate of each component of the Residual Monthly Costs;
- n) the FHMC for each hour; and
- o) the flow of inadvertent energy for each hour.

7.15.1A The SO shall Publish the following Market Participant settlement-related information:

- a) the Imbalance Quantity – Generation, or IQG, for each Market Participant for each hour;

- b) the Imbalance Quantity – Load, or IQL, for each Market Participant for each hour; and
- c) the cumulative energy variance quantities for each Market Participant for the Settlement Period.

7.15.2 The settlement-related information referred to in sections 7.15.1 and 7.15.1A in respect of a given Settlement Period shall be Published no later than the seventh Business Day of the following month.

7.15.3 The SO shall ensure that its internal procedures and systems relating to the functions and responsibilities of the SO under this Chapter are subject to an independent design and performance review or audit within five years of the date on which the procedures and systems become operational and thereafter no less than every five years. The results of each such review or audit, excluding any Confidential Information or information the disclosure of which could jeopardise the integrity of the Integrated Electricity System, shall be Published by the SO. The process will commence within one year of Systems Implementation Date and intermediate results of that process will be Published annually by the SO, excluding any Confidential Information or information the disclosure of which could jeopardise the integrity of the Integrated Electricity System.