Énergie NB Power

New Brunswick
Electricity Business Rules

Chapter 3
Reliable Operations

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CHAPTER 3 – RELIABLE OPERATIONS

3.0 System Operator Roles and Responsibilities

3.0.1 The System Operator (the "SO") is responsible for maintaining operational Reliability of the Integrated Electricity System (the "IES").

3.0.2 In fulfilling its responsibility, the SO authorities include:

a) Directing the operation to ensure the Reliability of the IES;
b) Setting Reliability Requirements for the IES where such requirements do not contradict or diminish Board Approved Reliability Standards;
c) Setting capacity requirements;
d) Ensuring adequate Ancillary Services;
e) Producing forecasts and assessments;
f) Coordinating Outages of generation and transmission facilities;
g) Entering into Operating Agreements with generators and loads; and
h) Entering into Interconnection Agreements with owners and operators of transmission outside of New Brunswick.

3.0.3 Operating Agreements

3.0.3.1 For the purpose of ensuring the safe and reliable operation of the IES or to supplement the operational requirements in Attachment J, Generation Connection Agreement, of the Open Access Transmission Tariff (the "Tariff), the SO may require at any time a Transmission Customer with a Generation Facility connected to the IES to have and maintain an Operating Agreement with the SO.

3.0.3.2 For the purposes of ensuring the safe and reliable operation of the IES or to supplement the operational requirements in Attachment G, Network Operating Agreement, of the Tariff, the SO may require at any time a Transmission Customer with a Load Facility connected to the IES to have and maintain an Operating Agreement with the SO.

3.0.4 SO Role as Reliability Coordinator and Balancing Authority outside New Brunswick

3.0.4.1 Authority of the SO to function as the Reliability Coordinator outside New Brunswick is formalized through Interconnection Agreements with those system operators within the designated boundaries of the Reliability Coordinator footprint.

3.0.4.2 Authority of the SO to function as the Balancing Authority outside New Brunswick is formalized through Interconnection Agreements with those system operators within the designated boundaries of the Balancing Authority area.

3.0.4.3 The costs incurred by the SO in performing Reliability Coordinator and Balancing Authority functions outside of New Brunswick are allocated as defined in the respective Interconnection Agreements.

3.0.5 Reliability Based Requests from the System Operator

3.0.5.1 Any party operating within the IES receiving a Reliability based request from the SO shall make all efforts to comply with such request and shall immediately notify the SO of any delays, or expected delays, and the reason for such delays in complying with the request.

3.1 Reliability Assessments

3.1.1 Reliability Assessment Requirements

3.1.1.1 The SO is responsible for power system Reliability Assessments and resource Adequacy Assessments, in accordance with the Reliability Standards, to ensure the IES is operated in a safe and reliable manner. This chapter provides a general overview of the assessments carried out by the SO and shall not be interpreted as limiting any aspect of the assessments or data requirements.

3.1.2 Power System Reliability Assessments

3.1.2.1 Power system Reliability Assessments shall, at a minimum, consist of:

a) The results of resource Adequacy Assessments to ensure generation patterns, ancillary services and applicable constraints are considered as inputs to the power system Reliability Assessments;

b) Seasonal assessments that will include all known Outages, constraints and system operating limits that are expected in the timeframe under review;

c) Next day assessments that will ensure the IES will operate in a known studied state that will include known Outages, generation patterns and system operating limits for the next day;

d) Current day assessments that will include changes in planned outages generation patterns and system operating limits; and

e) Mitigation plans, as required, to ensure any potential limit violations identified in the above power system reliability assessments are addressed.

3.1.3 Resource Adequacy Assessments

3.1.3.1 Resource Adequacy Assessments shall at a minimum consist of:

a) A forecast of demand and Capacity Based Ancillary Services (“CBAS”) requirements for the NB Balancing Area.

b) A determination of the capacity requirements of the NB Balancing Area.

c) A determination of net generation margins for the NB Balancing Area which shall include:

i. approved Outages and derations to Transmission and Generation Facilities,

ii. a consideration for Forced Outage rates

iii. capacity located outside New Brunswick if the Transmission Provider determines such inclusion to be appropriate.

iv. energy supply limitations of Generation Facilities including Non-Dispatchable Variable Generation Facilities.

v. A determination of capacity resources required within a particular Zone or region in order to maintain Reliability within that zone or region.

3.1.4 Reliability Assessment Data Requirements

3.1.4.1 To support Reliability Assessments, Transmission Users shall respond to data requests from the SO in the timeframes prescribed by the SO.

3.1.4.2 To support the timely assessments referred to in section 3.1.2.1(c), the Transmission Users as notified to submit such data under section 3.1.4.1, shall submit the necessary data to the SO by 11:00 a.m. Atlantic Time on the corresponding Day Ahead.

3.2 Ancillary Services

3.2.1 Incremental Operating Reserve

3.2.1.1 Where one or more transactions create exposure to a contingency in excess of the Incremental Operating Reserve Threshold, each Transmission User responsible for any such transaction shall self-supply its proportionate share of the Incremental Operating Reserve beyond the Incremental Operating Reserve Threshold required by the first or second contingency event, respectively.

3.2.1.2 In the event exposure to a first or second contingency in excess of the Incremental Operating Reserve Threshold arises the SO shall source Incremental Operating Reserve to account for any self-supply shortfall. The SO shall recover the costs incurred in sourcing such Incremental Operating Reserve from each Transmission Customer responsible for the quantity that is not self-supplied.

3.2.2 Forecasting and Allocation of Capacity Based Ancillary Services Requirements for the Maritimes Area

3.2.2.1 The SO shall enter into agreements with the operators of other transmission systems as may be required to give effect to, and to govern their respective rights and obligations as reflected in this section 3.2.

3.2.2.2 The SO shall prepare forecasts and determine the allocation for CBAS based on Reliability needs and shall consider arrangements with respect to neighbouring systems.

3.2.2.3 The SO shall prepare forecasts of requirements for CBAS for the Maritimes Area. In so doing, the SO shall separately identify any Operating Reserve requirement attributable to any Facility having a rated capacity of more than the Incremental Operating Reserve Threshold, as well as any transmission contingency in excess of the Incremental Operating Reserve Threshold.

3.2.2.4 On the basis of the forecasts prepared under section 3.2.2.3, but excluding any Operating Reserve requirement attributable to any Facility having a rated capacity of more than the Incremental Operating Reserve Threshold or to a source loss arising from a transmission contingency in excess of the Incremental Operating Reserve Threshold , the SO shall determine:

a) First, the CBAS requirement to be fulfilled by the operator of the Transmission System in Nova Scotia, respecting applicable Reliability Standards, shall be in accordance with the provisions of the applicable agreement between the SO and that operator; and
b) Frist, the load ratio share of the CBAS requirement to be fulfilled by each of the operators of the Transmission System in the province of Prince Edward Island and the operator of the Transmission System in northern Maine.

Such ratio shall be determined on the basis of the historical NCP billing data for each load over the previous calendar year and shall be used to determine each load's proportionate share of the NB Balancing Area CBAS requirement. Each January the load ratio share for each load will be calculated as a percentage obligation and provided by the SO and this percentage will apply for the 12-month period February to January, inclusive.

The SO shall perform the allocation referred to in this section 3.2.2.4 for each CBAS.

3.2.2.5 The SO shall prepare forecasts for Regulation and Load Following for Wind Power Generators and shall determine:

a) Incremental Regulation and Load Following service requirements to address the aggregate impact of wind power generators in the NB Balancing Area.

b) The ratio share, based on the net capacity of all wind power generators in the NB Balancing Area measured in MW, of the incremental Regulation and Load Following service produced by each of the operators of the wind power generators or the operators of the transmission to which the Facility is connected if the respective services are not being purchased under the Tariff.

3.2.3 The SO shall have authority to effect the activation of resources to provide CBAS in accordance with the agreements referred to in section 3.2.2.1.

3.2.4 Ancillary Services Self-Supply, Nomination, and Monthly Procurement

3.2.4.1 Entities within the NB Balancing Area supplying CBAS shall satisfy the Ancillary Services Operational Requirements specified in Appendix E, in order to qualify for the supply of that particular service.

3.2.4.2 The Transmission Provider shall commit to provide Regulation, Load Following, and Operating Reserve capacity services for a given month based on the difference between the forecasted requirements for such services, and the total self-supply.

3.2.4.3 External Loads Facilities, who wish to self-supply an Ancillary Service may do so provided the agreements between system operators referenced in section 3.2.2.1 define the nomination, activation and monitoring of such a service including the SO authority to effect the activation of the applicable service.

3.2.4.4 If a Transmission User self-supplies more than 100% of their monthly obligation, there is no credit. If a Transmission User self-supplies less than 100%, they are charged for the difference in accordance with the Tariff. The Ancillary Service charges for each Transmission User shall be determined each month by the SO.

3.3 Scheduling and Dispatch

3.3.1 Scheduling and Dispatch Objectives

3.3.1.1 The SO shall in sequence, with reliability being paramount:

a) Economically commit and dispatch those resources owned by the Corporation or under contract to supply to the Corporation.

b) To the extent that the commitments and dispatches of those resources are not sufficient to ensure Reliability of the IES or of any Zone, support the Supply of Emergency Energy or Security Energy, the SO shall utilize third party resources by committing, assigning them Must Run Status or Re-dispatching them.

3.3.2 Third Party Generator Re-dispatch/Must Run Compensation

3.3.2.1 Respecting sections 3.3.10.1 (Real Time Operation) and 3.4 (Emergency), for those instances where a Third Party Generator is assigned Must Run Status or is Re-dispatched, the Third Party Generator may choose to arrange an export transaction.

In absence of an export transaction the resource will be compensated according to section 4.8, based upon Dispatch Data submitted in section 3.3.3.

3.3.3 Third Party Generator Dispatch Data

3.3.3.1 A Third Party Generation Facility shall submit, and update accordingly, cost estimates including start-up and minimum run costs for use by the SO in Re-dispatch or Must-Run of such Generating Facilities.

3.3.3.2 The SO may request additional supporting data and may review or audit data submitted under this section at any time within a year of the Re-dispatch event to which it applies. When requested, supporting data shall include fuel suppliers' invoices for the cost of incremental fuel.

3.3.3.3 The Third Party Generation Facility shall promptly submit any additional data thus requested, and shall assist the SO in any review or audit.

3.3.3.4 If the SO determines that such additional data, review or audit reveals any Re-dispatch settlement to have been in error, it may following notice to the Third Party Generation Facility make appropriate settlement adjustments.

3.3.3.5 Generator Dispatch Data shall be submitted in the manner and form required by Appendix D.

3.3.4 Provisional Balanced Schedules

3.3.4.1 A Balanced Schedule shall be submitted in the manner and form required by Appendix C and shall comply with the applicable requirements of this Chapter.

3.3.4.2 A Transmission User wishing to have the SO schedule an energy or Ancillary Service transaction on a Dispatch Day shall, except as otherwise noted in sections 3.3.4.3

and 3.3.5.3., by 11:00 a.m. Atlantic Time on the corresponding Day Ahead, submit to the SO a Provisional Balanced Schedule comprising of:

a) A Balanced Schedule of energy flows utilizing Firm Point-to-Point Service, specifying injection Point of Receipt and withdrawal Delivery Points, including those at Interconnections, and the quantities of energy to be injected and withdrawn at each, to take account of transmission losses in accordance with the Tariff;
b) A Balanced Schedule of energy flows utilizing Network Integration Service, specifying injection Points of Receipt and withdrawal Delivery Points or Virtual Delivery Points, including those at Interconnections where not prohibited by the Tariff, and the quantities of energy to be injected at each, taking account of transmission losses in accordance with the Tariff; and
c) Schedules of self-supplied Ancillary Services.

3.3.4.3 A Transmission User shall by 1:00 p.m. Atlantic Time on the Day Ahead submit any new or revised updates to its Provisional Balanced Schedule if the need for such schedule updates could not have been known by the deadline noted in section 3.3.4.2.

3.3.5 Provisional Balanced Schedule, Assessment and Control Actions.

3.3.5.1 Based on the Provisional Balance Schedule submissions up to 1:00 p.m. Atlantic Time, the SO shall complete an assessment of the Provisional Balanced Schedules and reassess as necessary subsequent revisions for the purposes of ensuring the reliability of the IES or any Zones within.

3.3.5.2 The SO shall notify the Transmission User of issues identified in 3.3.5.1 and the changes required that may include those actions described in section 3.4.

3.3.5.3 A Transmission User may, at any time prior to 3:00 p.m. Atlantic Time on the Day Ahead, update its Provisional Balanced Schedule for the corresponding Dispatch Day by submitting a new or revised Provisional Balanced Schedule, subject to continued compliance with any instruction issued under section 3.3.5.2. Such updated Provisional Balanced Schedule if accepted by the SO shall supersede all earlier Provisional Balanced Schedules.

3.3.6 Generation Schedules

3.3.6.1 Transmission Users submitting Balanced Schedules that include injections from Generation Facilities connected to the IES shall submit Generation Schedules that:

- Are consistent with the Generation Facilities' capabilities;
- Are consistent with the quantities included in the Transmission User's Balanced Schedules;
- Meet the same Tariff and Business Rules scheduling deadlines that apply to Balanced Schedules where any submissions beyond 1:00 p.m. Atlantic Time will require SO approval;
- Provide information as indicated in the following table for the Transmission User's generation scheduling mode as approved by the SO. The default mode is self-scheduling. SO approval for self-committing mode requires the Transmission User's submission of an unambiguous method by which the SO can assume or create a feasible generation dispatch plan.

Generation Scheduling Mode	Schedule Information
Self-Committing	Generation commitment in each interval ("1" for on and "0" for off)
Self-Scheduling	Average MW in each interval

3.3.7 Final Day Ahead Commitment Schedule

3.3.7.1 Accepted Provisional Balanced Schedules, including those updated and accepted under section 3.3.5.3 where applicable, shall become the Final Day Ahead Balanced Schedule (the "FDABS").

3.3.7.2 In accordance with section 3.3.1.1, the SO shall, on the Day Ahead, optimize the dispatch for the 24 hours of the corresponding Dispatch Day in accordance with FDABS, updated Ancillary Service requirements, updated forecasts, scheduled exports, Third Party Generator Schedules, potential contingencies and the updated status of IES, including Outages and limits. On that basis, the SO shall prepare a Final Day Ahead Commitment Schedule (" FDACS").

3.3.7.3 The SO shall by 4:00 p.m., Atlantic Time on the Day Ahead make available to each Transmission User in respect of its own Generation Facilities its commitment schedule.

3.3.7.4 If a Transmission User becomes aware of any circumstance, excluding the normal production variability associated with Non-Dispatchable Variable Generators, that will or is likely to prevent that Transmission User from fulfilling its commitment schedule or any update thereto issued by the SO, it shall promptly notify the SO of the circumstances and of the likely consequences of such circumstances.

3.3.7.5 The Transmission User shall, working with the SO, promptly submit for the SO's acceptance revisions to its Balanced Schedule that address reliability concerns identified in section 3.3.7.4.

3.3.8 Hour Ahead Dispatch

3.3.8.1 A Transmission User may submit a Balanced Schedule change request up to 30 minutes prior to the hour in accordance with the Tariff. The SO may reject any

Balanced Schedule change request that cannot be accommodated. The Balanced Schedule existing at 30 minutes prior to the start of the Dispatch Hour shall, subject to section 3.3.8.2, be the Final Hourly Balanced Schedule (the "FHBS") for that Dispatch Hour.

3.3.8.2 The SO may adjust a FHBS for settlement purposes to take account of:

a) The failure of any Balanced Schedule to pass check-out with other system operators;
b) The curtailment of any transaction underlying a Balanced Schedule as a result of transmission loading relief effected in accordance with NERC standards and practices; or
c) The recall of any export or import transaction in accordance with the relevant provisions of the Balanced Schedule and Interconnection Agreements, including in respect of Operating Reserve and unit contingent import transactions, but not unit contingent export transactions recalled as a result of the associated unit contingency event.

3.3.8.3 A Transmission User for a Non-Dispatchable Variable Generator and similar facilities located in the NB Balancing Area must provide the SO with telemetry data via the SO SCADA system in respect of variable factors that affect production. This data may be used to adjust Balanced Schedules for Non-Dispatchable Variable Generators.

3.3.9 Final Hourly Commitment Schedule

3.3.9.1 In accordance with section 3.3.1.1, the SO shall prepare a Final Hourly Commitment Schedule (FHCS) for the Dispatch Hour, together with an updated Commitment Schedule for up to three hours following the Dispatch Hour using updated load and Non-Dispatchable Variable Generators production forecasts, and the FHBS.

The SO shall use the FHCS as the basis for the Dispatch Instructions to be issued under section 3.3.9.2(d).

3.3.9.2 During the hour prior to the start of each Dispatch Hour, the SO shall:

a) Update its load forecasts, Non-Dispatchable Variable Generators production forecast and Ancillary Service Requirements;
b) Update the status of the IES, including Outages and limits;
c) Review Interconnection transactions, and confirm or deny approval in accordance with applicable Interconnection Agreements and the Reliability Standards; and
d) No less than ten minutes prior to the start of the Dispatch Hour, issue required Dispatch Instructions to Transmission Users in respect of Generation Facilities.

3.3.9.3 Dispatch Instructions issued for Generation Facilities under section 3.3.9.2(d) may include:

a) Instructions to operate at a given level of net power output;
b) Instructions to ramp up or down at given rates over a given period or until reaching a given level of output;
c) If the Generation Facility has an obligation to provide an Ancillary Service, instructions in accordance with the Facility's Generation Connection Agreement or Operating Agreement as may be required under Ancillary Services Operational Requirements specified in Appendix E; and
d) In the case of Non-Dispatchable Variable Generators, Dispatch Instructions are not expected to be followed and will be equal to the lesser of the SO's forecast production or the Power Control Instruction.

3.3.9.4 The SO may also issue Dispatch Instructions at any time to operate the Generation Facility or an individual generation unit at a particular voltage level, power factor or level of reactive power output or absorption.

3.3.9.5 A Transmission User with a Generation Facility shall acknowledge receipt of its Dispatch Instructions and shall use its best efforts to operate its Generation Facilities in accordance with such Dispatch Instructions. The Generation Facilities shall operate within the tolerance band described in section 3.3.9.9 or in accordance with the compliance requirements referred to in section 3.3.9.10, as applicable.

3.3.9.6 Dispatch Instructions continue in effect until superseded by later Dispatch Instructions.

3.3.9.7 In the event that a Transmission User with a Generation Facility does not receive a Dispatch Instruction at a time when it reasonably expects to receive such a Dispatch Instruction, it shall promptly contact the SO for clarification.

3.3.9.8 Sections 3.3.9.5, 3.3.9.6 and 3.3.9.7 do not apply to Non-Dispatchable Variable Generators. The SO may reduce dispatch of the facility via Power Control Instructions issued via the SO SCADA system.

3.3.9.9 With the exception of Non-Dispatchable Variable Generators the tolerance band for compliance with energy Dispatch Instructions shall be the greater of +/- 10 MW or 3% of (i) the dispatched output level in the case of a Generation Facility, or (ii) the load reduction in the case of Ancillary Service from a Load. Compliance within this band of energy Dispatch instructions does not relieve a Facility from applicable Energy Imbalance charges

3.3.9.10 The requirements for the provision of an Ancillary Service shall be as set forth in the Ancillary Services Operational Requirements specified in Appendix E and in adherence with applicable Reliability Standards and Good Utility Practice

3.3.9.11 If a Transmission User with a Generation Facility becomes aware of any circumstance that will or is likely to prevent that Transmission User with a Generation Facility from complying with its Dispatch Instructions the Transmission

User with a Generation Facility shall promptly notify the SO of the reasons for the inability to comply and of the consequences of such inability.

3.3.10 Real Time Operation

3.3.10.1 Using real time information, forecasts and anticipated schedules the SO shall initiate such control actions as may be required to maintain Reliability of the IES and of any Zone including those actions described in section 3.4.

3.3.10.2 On a continuous basis the SO shall issue Power Control Instructions in respect of the output settings to Non-Dispatchable Variable Generators via the SO's SCADA system. The Power Control Instruction would normally be set at the maximum output of the Facility.

3.3.10.3 Activation of reserve will be performed with emphasis on reliability and at the SO's discretion. All else being equal, the SO will activate the required reserve from all suppliers providing the service on a pro rata basis in proportion to the respective supply.

3.4 Emergency and High Risk Operating States and Emergency Energy

3.4.1 The SO shall develop and have accessible to Transmission Users, procedures to be applied in the following circumstances:

a) Where the SO identifies an actual or forecast shortage in the supply of energy or the provision of Ancillary Services other than Black Start Capability Service;

b) Where the SO identifies an actual or forecast surplus energy supply; and

c) Where the SO identifies or anticipates an increase in the risk of the occurrence of contingency events within the IES or in an electricity system that is interconnected with the IES, or an increase in the consequences of a contingency event that may occur.

3.4.2 Where the SO receives a request for the provision of Emergency Energy under and in accordance with an Interconnection Agreement, it shall provide such Emergency Energy to the requesting party subject to the terms of the Interconnection Agreement.

3.5 Outage Planning and Coordination

3.5.1 Planned Outage requests shall be made no later than 11:00 a.m. Atlantic Time two business days before the Outage is scheduled to begin to the extent possible, however, planned Outage requests made later shall be considered if practicable. To avoid scheduling conflicts, it is recommended the party use its best efforts to submit Outage requests to the SO at the earliest opportunity.

3.5.2 The requesting party of a planned Outage that has already been submitted for approval shall notify the SO as soon as possible of any required changes.

3.5.3 No Outage request shall be approved until it has been assessed by the SO.

3.5.4 The SO shall make best efforts to assess all known Outages and their impact on system Reliability as soon as practical. All known Outage requests shall be accordingly assessed in the seasonal or planning horizon, next-day and current day timeframes.

3.5.5 In performing Outage coordination activities the SO shall minimize, as much as practicable, any disruption to the operations of Transmission Users. The SO shall use best efforts to coordinate all Outages to minimize as much as practicable the economic, safety and reliability impacts of the Outages.

3.5.6 Outage Approvals, Rejections and Retractions

3.5.6.1 Where Outage requests pose unacceptable risk to safety or Reliability, and such risks cannot be reasonably mitigated, the requests shall be denied by the SO.

3.5.6.2 Where there is a conflict between two or more Outage requests, the SO will work in consultation with the parties to reach a solution. Where a solution cannot be found, Outage priority will be determined based on the Outage submission request dates.

3.5.6.3 In cases where an Outage request was approved by the SO and conditions within the IES have changed such that the outage will pose a risk to safety or system Reliability, the SO shall retract the approval of the Outage and the work shall not begin until such time it is deemed acceptable by the SO.

3.5.6.4 In cases where an Outage request was approved by the SO and work has already begun, should the conditions of the IES change such that the Outage will pose an unacceptable risk to safety or system Reliability, the SO shall notify the affected parties. The affected parties shall make best efforts to restore the system to the configuration as determined by the SO and the Outage approval shall be considered retracted and no longer in force or effect. If the affected parties cannot restore the system to the configuration as directed by the SO in an acceptable timeframe, the SO shall take control actions to ensure the IES is operated in a safe and reliable manner.

3.5.7 The SO shall develop and have accessible to Transmission Users an operating procedure further describing Outage planning and coordination activities.

3.6 Forced Outages and Forced Outage Requests

3.6.1 A Transmission User may take whatever reasonable action it deems necessary for reasons of safety, to protect its equipment from immediate material harm or to prevent serious environmental damage arising from unforeseeable events.

3.6.2 Transmission Users that require an immediate Forced Outage shall inform the SO as soon as practicable as to the reason for the Forced Outage and the expected duration of the Forced Outage. The Transmission User shall give the SO timely updates, throughout the Forced Outage, as to the Outage status and return to service time.

3.6.3 Transmission Users that foresee a need for a Forced Outage shall inform the SO of such need and request approval for the equipment to be taken out of service. If requested by the SO for Reliability reasons, the requesting party shall make all practical efforts to keep the equipment in service and postpone the Outage.

3.7 Reliability Requirements

3.7.1 The Transmission Provider in ensuring the reliable planning, design and operation of the IES may set Reliability Requirements. Reliability Requirements will be applicable, on a non-discriminatory basis, to those parties that are material to the Reliability of the IES.

3.7.2 Appendix F, lists Northeast Power Coordinating Council (“NPCC”) criteria and directories established by the Transmission Provider to be Reliability Requirements necessary for the reliability of the IES. The Transmission Provider may adopt or develop additional Reliability Requirements which may not be limited to those of NPCC. Appendix F will be updated with any such additions or modifications.

3.7.3 Based on Appendix F, the Transmission Provider will notify Transmission Users of any Reliability Requirements applicable to the Transmission User and their obligations to ensure satisfactory compliance with the requirements.