ISO Rules
Part 500 Facilities
Division 503 Technical & Operating Requirements
Section 503.15 Interconnected Electric System Protection

Applicability

1 Section 503.15 applies to:

(a) the **legal owner** of a **generating unit** directly connected to the **transmission system**, with a **maximum authorized real power** rating greater than or equal to 18 MW;

(b) the **legal owner** of an **aggregated facility** directly connected to the **transmission system**, with a **maximum authorized real power** rating greater than or equal to 67.5 MW;

(c) the **legal owner** of an **energy storage resource** directly connected to the **transmission system**, with a **maximum authorized real power** rating greater than or equal to 18 MW;

(e) the **legal owner** of a **transmission facility** with a rated voltage greater than or equal to 100 kV; and

(f) the **ISO**.

Protection System General Requirements

Basic Requirements

2 The **legal owner** must design, engineer and construct all **protection systems** to:

(a) successfully detect all phase-to-ground with ground impedance less than 5 ohms, phase-to-phase-to-ground with ground impedance less than 5 ohms, phase-to-phase, and 3 phase faults on the protected equipment within the zone of protection;

(b) initiate isolation of the faulted equipment from all sources;

(c) coordinate with any adjacent **protection systems** and remain stable for faults external to the zone of protection; and

(d) ensure cascade tripping does not occur.

Requirement for 2 Protection Systems

3(1) Except as otherwise specified in this Section 503.15, all facilities of the applicable entities listed in subsection 1 must be equipped with no less than 2 independently operating **protection systems**.

(2) Each of the 2 **protection systems** must:

(a) meet the operate time requirements set out in subsection 4;

(b) include an independent secondary potential transformer winding, independent current transformer core, independent communication channel, independent interconnecting cables, independently protected direct current power supply and independent trip circuit, including breaker trip coil; and

(c) operate independently of and without interference from the other **protection system**.

(3) The relay for one of the **protection systems** must be from a different manufacturer than the relay for the other **protection system**, or must operate on a different protection principle from the other **protection system**.

Protection Relay Operate Times

4(1) For bus protection relays, the primary protection relay operate times for phase-to-phase or 3 phase bus faults must be:

(a) specified to not exceed; or

(b) tested to confirm they do not exceed,

the maximum operate times, expressed in cycles, in the following Table 1:

Table 1

Bus Protection Maximum Operate Times

Voltage	Operate Time
500 kV	1.50 cycles
240 kV	1.50 cycles
138 kV	2.00 cycles

(2) For line distance relays, the primary protection relay operate times for phase-to-phase or 3 phase faults for near end faults on **bulk transmission lines** with 2 terminals and 2 sources that are long enough to have an effective zone 1 distance protection must be:

(a) specified to not exceed; or

(b) tested to confirm they do not exceed,

the maximum operate times, expressed in cycles, in the following Table 2:

Table 2

Line Distance Protection

Voltage	Operate Time
500 kV	1.00 cycles
240 kV	1.00 cycles
138 kV	2.00 cycles

(3) For line differential relays, the primary protection relay operate times for phase-to-phase or 3 phase faults on **bulk transmission lines** with 2 terminals and 2 sources must be:

(a) specified to not exceed; or

(b) tested to confirm they do not exceed,

the maximum operate times, expressed in cycles, in the following Table 3:

Table 3

Line Differential Protection

Voltage	Operate Time
500 kV	2.00 cycles
240 kV	2.00 cycles
138 kV	2.00 cycles

(4) The primary protection relay operate times for phase-to-phase or 3 phase faults:

(a) within the zone of protection of equipment, including transformers, capacitor banks, reactors, and static VAR compensators; and

(b) close to the equipment's high voltage bushings that are connected to the **interconnected electric system**;

must be:

(c) specified to not exceed; or

(d) tested to confirm they do not exceed,

the maximum operate times, expressed in cycles, in the following Table 4:

Table 4

Equipment Protection

Voltage	Operate Time
500 kV	1.50 cycles
240 kV	1.50 cycles
138 kV	2.00 cycles

Instrument Transformers

5(1) The **legal owner** must ensure the facility uses protection class voltage and current transformers.

(2) Each **protection system** must have separate current cores and utilize separate secondary voltage transformer windings.

Voltage Transformers

6(1) Voltage transformers for a facility must be wire wound, capacitive or optical voltage transformers, and any other form of transformer is prohibited.

(2) For 240 kV or higher voltage facilities, **protection system** devices that require voltage transformer inputs to provide protection functions must be connected to voltage transformers that are directly connected to the protected **system element**.

(3) For 144 kV or lower voltage facilities that utilize simple bus design, the use of common bus voltage transformers is acceptable.

Fuse Failure Alarm for Voltage Transformers

7 A voltage transformer used for protective purposes, including synchronism checking, must have a loss of potential alarm.

Current Transformers

8(1) A current transformer used in a **protection system** must be either magnetic or optical, and must not be the limiting element in the **transmission facility's** rating.

(2) The maximum available current transformer ratio must be sized for the ultimate fault level of the facility as set out in the functional specification.

(3) A current transformer used in a **protection system** must meet the 2.5 L low internal secondary impedance accuracy requirement as set out in *CAN/CSA-C60044-1:07, Instrument transformer – Part 1: Current transformers, Table 1B*, or an equivalent accuracy requirement at its maximum possible ratio, regardless of the ratio actually being utilized.

Protection System Power Supply

9(1) The direct current supply for each of the 2 **protection systems** for a facility must be protected such that a direct current fault within one of the **protection systems** is isolated and will not affect the operation of the other **protection system**.

(2) A **protection system** must be such that it may be isolated from its direct current supply without affecting the operation of any other **protection system**.

Event Capture

10(1) For each zone of protection, there must be a **protection system** with no less than one relay or digital style fault event recorder to capture wave form event records.

(2) Faults within the zone of protection must trigger an event capture.

(3) The event recorder must be able to time stamp an event to an accuracy level within 1.0 milliseconds of Universal Time Constant.

(4) All event records must be retrievable within 24 hours of request.

Bulk Transmission Line

Ground Fault Resistance Coverage

11 If a **bulk transmission line** experiences a fault of the following type, then each of the 2 **protection systems** for the **bulk transmission line** must initiate isolation of the fault:

(a) single line-to-ground, with a minimum impedance of 5 ohms; or

(b) phase-to-phase-to-ground with a minimum impedance of 5 ohms.

Auto-Reclosing

12(1) The **ISO** must, for 240 kV or higher voltage **bulk transmission lines**, specify the type of auto-

reclosing in the functional specification.

(2) When single pole trip and reclose is specified in the functional specification for a 240 kV or higher voltage **bulk transmission line**, the following must be met:

(a) auto-reclose single pole upon a single phase fault and not reclose for any multiphase fault, unless 3 pole auto-reclosing operation or no reclosing is specifically requested in the functional specification;

(b) not allow for more than one attempt at each end of the **bulk transmission line** to auto-reclose the **bulk transmission line**; and

(c) have adequate dead time to ensure the secondary arc is extinguished.

(3) A 144 kV or lower voltage **bulk transmission line** must:

(a) trip and auto-reclose 3 pole once for all fault types unless no reclosing is specified in the project functional specification and

(b) have adequate dead time to ensure any secondary arc is extinguished

Auto–Reclosing Prohibition

13(1) If a **bulk transmission line** is a dedicated single line connecting from any **generating unit**, **aggregated facility**, or **energy storage resource** to the **interconnected electric system**, then the installation of auto-reclosing equipment is prohibited, unless specifically provided for in the functional specification.

(2) Auto-reclosing on cables is not permitted.

Switch onto Fault

14 Instantaneous tripping must occur for the entire length of the **bulk transmission line** if upon an auto-reclose the fault re-establishes.

Synchronism Check Relaying

15 For all 240 kV and higher voltage **bulk transmission line** breakers, a synchronism check relay must be used for all 3 pole closing but those breakers that switch only a load transformer, a capacitor, or a reactor, and have no power source of their own, do not require a synchronism check relay.

Distance or Impedance Protection Systems

16 A **protection system** for a **bulk transmission line** utilizing distance or impedance protection as a primary manner of protecting a 2 terminal, 2 source **bulk transmission line** must have:

(a) no instantaneous distance element, such as zone 1, reach past the remote bus; and

(b) at least 1 distance element, such as zone 2, overreach the remote bus.

Differential Protection Systems

17(1) On **bulk transmission lines**, the use of differential protection is acceptable.

(2) Upon communication failure:

(a) the **protection system** must still be capable of fault detection and tripping; and

(b) protection relay operate times slower than those specified in subsection 4(3) are acceptable.

Stub Protection

18 Any stubs created by opening line motorized disconnects must be protected by 2 **protection systems**.

Protection System Communications

19 Each communication system utilized in a **protection system** must be designed to have an overall availability of not less than 99.99% unless specified otherwise in the functional specification.

3 Terminal Lines

20(1) For a new 3 terminal **bulk transmission line**, regardless of source or load locations, communications between all 3 terminals is required.

(2) Notwithstanding subsections 2(c) and 20(1), if a protection study is undertaken identifying the level of mis-coordination and associated risks, the **ISO** may choose to grant an exemption in the functional specification.

(3) Clearing times for faults on the 3 terminal line must comply with the requirements the **ISO** specifies in the functional specification for the facility.

Bulk Transmission Line Connected Reactors

21(1) The line reactor for a 240 kV or higher voltage **bulk transmission line** must be equipped with 2 **protection systems**.

(2) The reactor **protection systems** must be in compliance with the following requirements:

(a) a phase reactor must be equipped with 2 differential **protection systems**;

(b) a phase reactor must be equipped with a phase and residual over-current **protection system**, which may be included in 1 of the differential **protection systems**;

(c) an oil-filled reactor must have non-electrical **protection systems** with the same requirement as an oil-filled transformer; and

(d) a neutral reactor must be either included in an overall zero sequence differential zone or equipped with a single phase differential **protection system** and must also be equipped with a second differential protection or over-current protection as backup.

Switch Onto Fault Protection – Manual Close

22(1) A **bulk transmission line** terminal must be equipped with switch onto fault protection as identified in subsection 14 for **operator**-initiated breaker close.

(2) For a manual switch onto fault event, auto-reclose must be blocked.

Positive, Negative, Zero, and Mutual Impedances

23 For the protection of a **bulk transmission line**, the **protection system** equipment and settings must take into account the zero sequence mutual coupling during fault conditions, and the under-reach or over-reach of the distance element must be either mitigated or the zone reaches adjusted accordingly.

500 kV Protection System Setting Verification

24 A 500 kV line **protection system** utilizing distance or impedance protection as its primary protection must have settings verified utilizing real-time digital simulation.

Substations

Transformers

25(1) All transformers with a base rating less than 25 MVA must have:

(a) one independent overcurrent **protection system** installed on the high voltage side;

(b) one independent differential **protection system**;

(c) an oil level alarm;

(d) a minimum of gas accumulation alarming and gas surge protection tripping; and

(e) 2 levels for thermal alarm and the time between the first alarm and the second alarm must allow time to take action to unload the transformer.

(2) A transformer with a base rating of 25 MVA or larger must have:

(a) one overcurrent **protection system** which may be combined with a differential protection **system**;

(b) 2 independent differential **protection systems**;

(c) an oil level alarm;

(d) a minimum of gas accumulation alarming and gas surge protection tripping; and

(e) 2 levels for thermal alarm and the time between the first alarm and the second alarm must allow time to take action to unload the transformer.

(3) All transformers with tertiary windings that are used for loads, such as station service, must have the tertiary windings included in the transformer differential protection zone.

240 kV and Higher Voltage Substation Bus Protection

26(1) All 240 kV and higher voltage substation buses must have 2 bus **protection systems**.

(2) All 240 kV and higher voltage substation bus **protection systems** must trip all associated breakers to isolate the fault.

144 kV and Lower Voltage Substation Bus Protection

27(1) All 144 kV and lower voltage substation buses must have 2 bus **protection systems.**

(2) If protection studies show that the remote line **protection systems** can clear a bus fault in 0.6 seconds, then the remote line **protection systems** can be considered to be one of the 2 **protection systems** required in subsection 27(1).

(3) All 144 kV and lower voltage substation bus **protection systems** must trip all associated breakers to isolate the fault.

Ring Bus Protection

28 Notwithstanding subsections 26 and 27, ring bus configured substations that have 2 overlapping

protection systems that are capable of stub protection as identified in subsection 18 do not require additional bus protection.

Substation Shunt Capacitor Banks

29(1) Auto-restoration of a faulted capacitor bank is prohibited.

(2) 2 over-current **protection systems** must be applied to shunt capacitor banks to detect major faults such as a phase-to-phase fault or phase-to-ground fault.

(3) For wye or wye-wye shunt capacitor banks, at least one **protection system** must be applied which provides both an alarm and a trip level to detect capacitor bank unit or capacitor bank element failure.

Substation Shunt Reactor Banks

30 The **protection systems** for shunt reactor banks must comply with the following:

(a) 144 kV and lower voltage reactors must be equipped with a minimum of 1 independent phase differential and one independent over-current **protection systems**;

(b) 240 kV and higher voltage reactors must be equipped with 2 differential **protection systems** and overcurrent protection which may be included in one of the differential **protection systems**; and

(c) an oil filled reactor, in addition, must have a minimum of gas accumulation alarming and gas surge protection tripping.

Breaker Failure Protection

31(1) All breakers must have a minimum of one breaker failure **protection system** and all protection trips excluding **remedial action scheme** trips must initiate a current or contact supervised breaker failure **protection system**.

(2) The **ISO** must identify the need for **remedial action schemes** to initiate breaker fail in the functional specifications on a project basis.

(3) For 240 kV and higher voltage breakers, the breaker failure **protection system** must utilize direct tripping of all remote breakers utilizing communications.

(4) For 144 kV and lower voltage breakers, a breaker failure **protection system** must be installed which trips all:

(a) local breakers; and

(b) remote breakers:

(i) by a communication system which, notwithstanding subsection 19, must be designed to have an availability of at least 99.5%; or

(ii) within a definite time period the **legal owner** of a **generating unit**, **aggregated facility**, **energy storage resource**, or **transmission facility**, as applicable, defines, and without thermally damaging additional facilities beyond the faulted facility.

(5) The maximum time delay for breaker fail operate time measured from the primary **protection system**'s trip output contact closing to the last local breaker receiving the open signal for solid single line-to-ground or 3 phase faults that generate high fault currents must not be longer than:

(a) 6 cycles, being 0.100 seconds, for 500 kV breakers;

(b) 7 cycles, being 0.117 seconds, for 240 kV breakers; and

(c) 12 cycles, being 0.200 seconds, for 138 kV and 144 kV breakers.

(6) For applications where free standing current transformers are used with live-tank breakers it is acceptable to have a breaker fail operation for faults located between the breaker and the current transformer.

Substation Transformer Ended Lines

32 For 144 kV and lower voltage transformer ended **transmission lines** without a breaker, the substation must be equipped with 2 independent direct transfer trip communication channels to trip any remote end breakers.

Generating Unit, Aggregated Facility, and Energy Storage Resource Protection

Inadvertent Energization

33 No facility may be designed, engineered or constructed such that there may be inadvertent energization of any **generating unit**, **aggregated facility**, or **energy storage resource**, including through the station service bus.

Protection from Interconnected Electric System Faults

34 The **legal owner** of a **generating unit**, **aggregated facility**, or **energy storage resource** must each ensure that their facilities have appropriate **protection systems** to protect the facilities from the effects of faults on the **interconnected electric system**.

Tripping

35(1) If a **generating unit**, **aggregated facility**, or **energy storage resource** fault occurs, the **protection system** at a minimum must isolate the fault from the **interconnected electric system** by opening the appropriate breakers and initiating breaker failure protection.

(2) If it is possible to energize or back-feed the **generating unit**, **aggregated facility**, or **energy storage resource** through the station service, then the **protection system** must also trip the low voltage station service breakers, including those with high-speed bus transfer schemes.

Auto-Reclosing

36 Auto-reclosing of generator breakers after a **generating unit**, **aggregated facility**, or **energy storage resource** fault is prohibited.

Synchronizing

37 A synchronous **generating unit**, **aggregated facility** or **energy storage resource** must be equipped with full synchronizing equipment, capable of assuming full control of the **governor system** and **automatic voltage regulator** during the synchronizing process.

60 Hz Synchronous Generating Units and Energy Storage Resources (other than Aggregated Facilities) Electrical Protection

38 A 60 Hz synchronous **generating unit** or **energy storage resource**, excluding any **aggregated facility**, must meet the following protection requirements:

(a) 2 **generating unit** differential **protection systems**;

(b) 2 **generating unit** and facility step up transformers **protection systems**;

(c) 2 high voltage bus **protection systems**; and

(d) **generating unit** excitation transformers must have 2 **protection systems**.

Out of Step Condition

39 For any 60 Hz synchronous **generating unit** or **energy storage resource**, excluding an **aggregated facility**, impedance protection at the **generating unit** or **energy storage resource** step-up transformer terminals must be applied to mitigate any out-of-step condition when an electric energy swing traverses the **generating unit**, **energy storage resource**, **generating unit** step-up transformer, or **energy storage resource** step-up transformer.

Aggregated Facilities and Energy Storage Resources (Excluding 60 Hz Synchronous Energy Storage Resources)

40 An **aggregated facility** or **energy storage resource**, excluding any 60 Hz synchronous **energy storage resources**, must meet the following protection requirements:

(a) 2 **aggregated facility** step-up transformer **protection systems**; and

(b) 2 high voltage bus **protection systems**.

Reverse Electric Energy Condition

41 Two **protection systems** must be capable of detecting reverse power flowing into the **generating unit** and the **generating unit** must be removed from service if either of the **protection systems** detects reverse power flow.

Revision History

Date	Description
2024-04-01	Amended, as approved in **Commission** Decision 28176-D01-2023 issued on June 13, 2023. See *Table of Concordance for the Transition from Division 502 to Division 503* on www.aeso.ca for further information regarding the change from Division 502 – Technical Requirements to Division 503 – Technical and Operating Requirements
2019-12-11	Removed duplication with new Section 103.14, Waivers and Variances; standardized functional specifications language; capitalized references to “Section”.
2018-09-01	Revised references to “wind aggregated generating facilities” to “aggregated generating facilities”; revised applicability section; and administrative revisions.

Date	Description
2016-08-30	Inclusion of the defined term **system element**.
2015-03-27	Replaced “effective date” with the initial release date in sections 2, 3 and 5; and replaced the word “Effective” in the Revision History to “Date”.
2012-12-31	Initial release