Alberta Reliability Standard
Disturbance Monitoring and Reporting Requirements
PRC-002-AB-4

A. Introduction

1. Title: Disturbance Monitoring and Reporting Requirements

2. Number: PRC-002-AB-4

3. Purpose: To have adequate data available to facilitate analysis of **disturbances** on the **bulk electric system**.

4. Applicability:

4.1. Functional Entities

4.1.1. the **ISO**;

4.1.2. the **legal owner** of a **transmission facility** that is part of the **bulk electric system**; and

4.1.3. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility** that are part of the **bulk electric system**.

5. Effective Date: January 1, 2028.

B. Requirements and Measures

R1. Each **legal owner** of a **transmission facility** must: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify buses that are part of the **bulk electric system** for which sequence of events recording and **fault** recording data is required by using the methodology in PRC-002-AB-4, Attachment 1.

1.2. Notify the other **legal owners** of **system elements** that are part of the **bulk electric system** directly connected[1] to those buses that are part of the **bulk electric system**, that sequence of events recording or **fault** recording data is required for those **system elements** that are part of the **bulk electric system**, only if the **legal owner** of a **transmission facility** who identified the buses that are part of the **bulk electric system** in Requirement R1, Part 1.1 does not have sequence of events recording or **fault** recording data. This notification is required within 90 **days** of completion of Requirement R1, Part 1.1.

1.3. Re-evaluate all buses that are part of the **bulk electric system** at least once every five calendar years in accordance with Requirement R1, Part 1.1 and notify other **legal owners** in accordance with Requirement R1, Part 1.2.

[1] For the purposes of this standard, "directly connected" **system elements** that are part of the **bulk electric system** are **system elements** that are part of the **bulk electric system** which are connected at the same voltage level within the same physical location sharing a common ground grid with the bus that is part of the **bulk electric system** identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

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M1. The **legal owner** of a **transmission facility** for Requirement R1, Part 1.1 has a dated electronic or hard copy list of buses that are part of the **bulk electric system** for which sequence of events recording and **fault** recording data is required, identified in accordance with PRC-002-AB-4, Attachment 1; has dated electronic or hard copy evidence that it notified other **legal owners** of **system elements** in accordance with Requirement R1, Part 1.2; and evidence that all buses that are part of the **bulk electric system** have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

R2. Each **legal owner** of a **transmission facility, legal owner** of a **generating unit,** and **legal owner** of an **aggregated generating facility** must have sequence of events recording data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the buses that are part of the **bulk electric system** identified in Requirement R1 and associated with the **system elements** that are part of the **bulk electric system** at those buses that are part of the **bulk electric system**. *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

M2. The **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** or the **legal owner** of an **aggregated generating facility** has evidence, electronic or hard copy, of sequence of events recording data for circuit breaker position as specified in Requirement R2. Evidence may include (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings or other equivalent evidence.

R3. Each **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** and the **legal owner** of an **aggregated generating facility** must have **fault** recording data to determine the following electrical quantities for each triggered **fault** recording for the **system elements** that are part of the **bulk electric system** it owns directly connected to the buses that are part of the **bulk electric system** identified in Requirement R1: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

3.1. Phase-to-neutral voltage for each phase of each specified bus that are part of the **bulk electric system**.

3.2. Each phase current and the residual or neutral current for the following **system elements** that are part of the **bulk electric system**:

3.2.1. Transformers that have a low-side operating voltage of 100 kV or above.

3.2.2. Transmission lines.

M3. The **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** or the **legal owner** of an **aggregated generating facility** has evidence, electronic or hard copy, of **fault** recording data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings or other equivalent evidence.

R4. Each **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** and the **legal owner** of an **aggregated generating facility** must have **fault** recording data as specified in Requirement R3 that meets the following: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

4.1. A single record or multiple records that include:

4.1.1. A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or

4.1.2. At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the **fault** as seen by the **fault** recorder.

4.2. A minimum recording rate of 16 samples per cycle.

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** or the **legal owner** of an **aggregated generating facility** has evidence, electronic or hard copy, that **fault** recording data meets Requirement R4. Evidence may include, (1) documents describing the device specification (Requirement R4, Part 4.2) and device configuration or settings (Requirement R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations or other equivalent evidence.

R5. The **ISO** must: *[Alberta Risk Rating: Lower] [Time Horizon: Long- term Planning]*

5.1 Identify **system elements** that are part of the **bulk electric system** for which dynamic **disturbance** recording data is required, including the following:

5.1.1. **Generating unit**(s) and **aggregated generating facility**(ies) with:

5.1.1.1. An individual **maximum authorized real power** greater than or equal to 450 MW.

5.1.1.2. An individual **maximum authorized real power** greater than or equal to 270 MW where the plant/facility aggregate **maximum authorized real power** rating is greater than or equal to 900 MW.

5.1.2. Any one **system element** that is part of the **bulk electric system** that is part of a stability (angular or voltage) related **system operating limit**.

5.1.3. Each terminal of a high voltage direct current circuit with a **normal rating** greater than or equal to 270 MW, on the alternating current portion of the converter.

5.1.4. One or more **system elements** that are part of the **bulk electric system** that are part of an **interconnection reliability operating limit**.

5.1.5. Any one **system element** that is part of the **bulk electric system** within a major voltage sensitive area as defined by an area with an in-service **under voltage load shed** program.

5.2 Identify a minimum dynamic **disturbance** recording coverage, inclusive of those **system elements** that are part of the **bulk electric system** identified in Requirement R5, Part 5.1, of at least:

5.2.1. One **system element** that is part of the **bulk electric system**; and

5.2.2. One **system element** that is part of the **bulk electric system** per 3,000 MW of the **ISO's** historical simultaneous peak Alberta internal load.

5.3 Notify all **legal owners** of identified **system elements** that are part of the **bulk electric system**, within 90 **days** of completion of Requirement R5, Part 5.1, that their respective **system elements** that are part of the **bulk electric system** require dynamic **disturbance** recording data.

5.3A Notify all **legal owners** of identified **system elements** that are part of the **bulk electric system**, in accordance with Requirement R5, Part 5.3, that the **legal owner** must stream the data to **ISO**.

5.4 Re-evaluate all **system elements** that are part of the **bulk electric system** within the **ISO**'s area at least once every five calendar years in accordance with Requirement R5, Parts 5.1 and 5.2, and notify **legal owners** in accordance with Requirement R5, Part 5.3 and Part 5.3A. to implement the re-evaluated list of **system elements** that are part of the **bulk electric system** as per the Effective Date.

M5. The **ISO** has a dated electronic or hard copy list of **system elements** that are part of the **bulk electric system** for which dynamic **disturbance** recording data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The **ISO** has dated evidence electronic or hard copy that each **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit** or the **legal owner** of an **aggregated generating facility** has been notified in accordance with Requirement 5, Part 5.3 and Part 5.3.A. Evidence may include, letters, emails, electronic files, hard copy records demonstrating transmittal of information, or other equivalent evidence.

R5.A1 Each **legal owner** notified in accordance with Requirement R5, Part 5.3A must stream identified **system element** data to the **ISO** in accordance with the requirements set out in the Institute of Electrical and Electronics Engineers *C37.118.1a–2014 – IEEE Standard for Synchrophasor Measurements for Power Systems* and *IEEE Standard C37.118.2-2011 – IEEE Standard for Synchrophasors Data Transfer for Power Systems* specific to a synchrophasor measurement unit.

M5.A1 The **legal owner** has evidence (electronic or hard copy) that stream data meets Requirement R5.A1. Evidence may include documents describing the device specification meets IEEE C37.118 standards.

R6. Each **legal owner** of a **transmission facility** must have dynamic **disturbance** recording data to determine the following electrical quantities for each **system element** that is part of the **bulk electric system** it owns for which it received notification as identified in Requirement R5: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

6.1. One phase-to-neutral or positive sequence voltage.

6.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3A. Unless requested by the **ISO** to stream data in accordance with Requirement R5.3A, **real power** and **reactive power** flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

6.4. Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The **legal owner** of a **transmission facility** has evidence (electronic or hard copy) of dynamic **disturbance** recording data to determine electrical quantities as specified in Requirement R6.

Evidence may include, (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings or other equivalent evidence.

R7. Each **legal** owner of a **generating unit** and the **legal owner** of an **aggregated generating facility** must have dynamic **disturbance** recording data to determine the following electrical quantities for each **system element** that is part of the **bulk electric system** it owns for which it received notification as identified in Requirement R5: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3A. Unless requested by the **ISO** to stream data in accordance with Requirement R5, Part 5.3A, **real power** and **reactive power** flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The **legal owner** of a **generating unit** or the **legal owner** of an **aggregated generating facility** has evidence (electronic or hard copy) of dynamic **disturbance** recording data to determine electrical quantities as specified in Requirement R7. Evidence may include, (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings or other equivalent evidence.

R8. Each **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** and the **legal owner** of an **aggregated generating facility** responsible for dynamic **disturbance** recording data for the **system elements** that are part of the **bulk electric system** identified in Requirement R5, must have continuous data recording and storage, unless it complies with subsection 6(2) of Section 503.13 of **ISO Rules**, *Synchrophasor Measurement System* or is required to stream data in accordance with Requirement R5, Part 5.3A. If the equipment was installed prior to October 1, 2019 and is not capable of continuous recording, triggered records must meet the following: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

8.2.1 Off nominal frequency trigger set at:

	Low	High
○ Intentionally left blank (inapplicable)	Intentionally left blank	Intentionally left blank
○ **Western interconnection**	<59.55 Hz	>61.0 Hz
○ Intentionally left blank (inapplicable)	Intentionally left blank	Intentionally left blank
○ Intentionally left blank (inapplicable)	Intentionally left blank	Intentionally left blank

8.2.2 Rate of change of frequency trigger set at:

○ Intentionally left blank (inapplicable)	Intentionally left blank	Intentionally left blank
○ **Western interconnection**	< -0.05625 Hz/sec	>0.125 Hz/sec
○ Intentionally left blank (inapplicable)	Intentionally left blank	Intentionally left blank
○ Intentionally left blank (inapplicable)	Intentionally left blank	Intentionally left blank

8.2.3 Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** and the **legal owner** of an **aggregated generating facility** has dated evidence electronic or hard copy of data recordings and storage in accordance with Requirement R8. Evidence may include (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings, or other equivalent evidence.

R9. Each **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** and the **legal owner** of an **aggregated generating facility** responsible for dynamic **disturbance** recording data for the **system elements** that are part of the **bulk electric system** identified in Requirement R5 must have dynamic **disturbance** recording data that meet the following: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

9.1. Input sampling rate of at least 960 samples per second.

9.2. Output recording rate of electrical quantities of at least 30 times per second.

M9. The **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** or the **legal owner** of an **aggregated generating facility** has evidence (electronic or hard copy) that dynamic **disturbance** recording data meets Requirement R9. Evidence may include (1) documents describing the device specification, device configuration, or settings (Requirement R9, Part 9.1; Requirement R9, Part 9.2); or (2) actual data recordings (Requirement R9, Part 9.2) or other equivalent evidence.

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R10. Each **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** and the **legal owner** of an **aggregated generating facility** must time synchronize all sequence of events recording and **fault** recording data for the buses that are part of the **bulk electric system** identified in Requirement R1 and dynamic **disturbance** recording data for the **system elements** that are part of the **bulk electric system** identified in Requirement R5 to meet the following: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2A. Synchronized device clock accuracy must be within ± 2 milliseconds of UTC. If requested by the **ISO** to stream data in accordance with Requirement R5, Part R5.3A, the **legal owner** must instead comply with the requirements set out in the Institute of Electrical and Electronics Engineers *C37.118.1a–2014 – IEEE Standard for Synchrophasor Measurements for Power Systems* and *IEEE Standard C37.118.2-2011 – IEEE Standard for Synchrophasors Data Transfer for Power Systems* specific to a synchrophasor measurement unit.

M10. The **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** or the **legal owner** of an **aggregated generating facility** has evidence, electronic or hard copy, of time synchronization described in Requirement R10. Evidence may include, (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or (3) station drawings or other equivalent evidence.

R11. Each **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** and the **legal owner** of an **aggregated generating facility** must provide, upon request, all sequence of events recording and **fault** recording data to the **ISO** for the buses that are part of the **bulk electric system** identified in Requirement R1. Unless the **legal owner** complies with subsection 6(2) of Section 503.13 of **ISO Rules**, *Synchrophasor Measurement System* or is required to stream data in accordance with Requirement R5, Part 5.3A, the **legal owner** must provide dynamic **disturbance** recording data for the **system elements** that are part of the **bulk electric system** identified in Requirement R5 to the **ISO** in accordance with the following: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

11.1. Data will be retrievable for the period of 10 **days**, inclusive of the **day** the data was recorded.

11.2. Data subject to Requirement R11, Part 11.1 will be provided within 30 **days** of a request unless an extension is granted by the **ISO**.

11.3. Sequence of events recording data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4. **Fault** recording and dynamic **disturbance** recording data will be provided in electronic files that are formatted in conformance with C37.111, *IEEE Standard Common Format for Transient Data Exchange (COMTRADE*), revision C37.111-1999 or later.

11.5. Data files will be named in conformance with C37.232, *IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME)*, revision C37.232-2011 or later.

M11. The **legal owner** of a **transmission facility**, the **legal owner** of a **generating unit,** and the **legal owner** of an **aggregated generating facility** has evidence, electronic or hard copy, that data was submitted upon request in accordance with Requirement R11 within 30 **days** of a request or other equivalent evidence.

R12. Each **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** and the **legal owner** of an **aggregated generating facility** must, unless requested by the **ISO** to stream data in accordance with Requirement R5, Part 5.3A, within 90 **days** of the discovery of a failure of the recording capability for the sequence of events recording, **fault** recording or dynamic **disturbance** recording data, either: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

12.1 Restore the recording capability, or

12.2 Submit a **corrective action plan** to the **ISO** and implement it.

M12. The **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** or the **legal owner** of an **aggregated generating facility** has dated evidence, electronic or hard copy, that meets Requirement R12. Evidence may include (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated corrective action plan transmittals to the **ISO** and evidence that it implemented the **corrective action plan** or other equivalent evidence.

R13. Each **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** and the **legal owner** of an **aggregated generating facility** must: *[Alberta Risk Rating: Lower] [Time Horizon: Long-term Planning]*

13.1. Within five (5) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have sequence of events recording or **fault** recording data as applicable for **system elements** that are part of the **bulk electric system** directly connected to the identified buses that are part of the **bulk electric system**.

13.2. Within five (5) calendar years of receiving notification under Requirement R5, Part 5.4, have dynamic **disturbance** recording data for **system elements** that are part of the **bulk electric system** identified during the re-evaluation, unless the **ISO** specifies, in the notification, an alternative implementation time of between 3 to 5 calendar years.

M13. The **legal owner** of a **transmission facility,** the **legal owner** of a **generating unit,** or the **legal owner** of an **aggregated generating facility** has dated evidence electronic or hard copy that meets Requirement R13. Evidence may include, letters, emails, drawings, or settings files or other equivalent evidence.

C. Compliance

[Intentionally left blank]

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

AESO Information Document ID #2018-022, *Disturbance Monitoring and Reporting Requirements* and any amendments made from time to time.

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G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NERC Reliability Standard PRC-002-4: Technical Rationale.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003).

Version History

Version	Effective Date	Description of Change
AB-4	2028-01-01	Revised based on the NERC's latest version, PRC-002-4, as approved by FERC (Docket No. RD23-4-000); added the Alberta deviation for streaming Dynamic Disturbance Recording data
AB-2	2019-10-01	Initial release

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Attachment 1

Methodology for Selecting Bulk Electric System Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored buses that are part of the **bulk electric system** for sequence of events recording and **fault** recording data required by requirement R1, each **legal owner** of a **transmission facility** must follow sequentially, unless otherwise noted, the steps listed below:

Step 1 Determine a complete list of buses that are part of the **bulk electric system** that it owns.

For the purposes of this standard, a single bus that is part of the **bulk electric system** includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in **fault** studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2 Reduce the list to those buses that are part of the **bulk electric system** that have a maximum available calculated 3-phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3 Determine the 11 buses that are part of the **bulk electric system** on the list with the highest maximum available calculated 3-phase short circuit MVA level. If the list has 11 or fewer buses that are part of the **bulk electric system**, proceed to Step 7.

Step 4 Calculate the median MVA level of the 11 buses that are part of the **bulk electric system** determined in Step 3.

Step 5 Multiply the median MVA level determined in Step 4 by 20%.

Step 6 Reduce the buses that are part of the **bulk electric system** on the list to only those that have a maximum available calculated 3-phase short circuit MVA higher than the greater of:

(a) 1,500 MVA; or

(b) 20% of median MVA level determined in Step 5.

Step 7 If there are no buses that are part of the **bulk electric system** on the list: the procedure is complete and no **fault** recording and sequence of events recording data is required. Proceed to Step 9.

If the list has 1 or more, but less than or equal to 11 buses that is part of the **bulk electric system**: **Fault** recording and sequence of events recording data is required at the bus that are part of the **bulk electric system** with the highest maximum available calculated 3-phase short circuit MVA as determined in Step 3. Proceed to Step 9.

During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified bus that is part of the **bulk electric system** is within 15% of the three phase short circuit MVA of the currently applicable bus that is part of the **bulk electric system** with

sequence of events recording and **fault** recording data then it is not necessary to change the applicable bus that is part of the **bulk electric system**. Proceed to Step 9.

If the list has more than 11 buses that are part of the **bulk electric system**: sequence of events recording and **fault** recording data is required on at least the 10% of the buses that are part of the **bulk electric system** determined in Step 6 with the highest maximum available calculated 3-phase short circuit MVA. Proceed to Step 8.

Step 8 Sequence of events recording and **fault** recording data is required at additional buses that are part of the **bulk electric system** on the list determined in Step 6. The aggregate of the number of buses that are part of the **bulk electric system** determined in Step 7 and in this Step 8 are at least 20% of the buses that are part of the **bulk electric system** determined in Step 6.

The additional buses that are part of the **bulk electric system** are selected, at the discretion of the **legal owner** of a **transmission facility**, to provide maximum **wide-area** coverage for sequence of events recording and **fault** recording data. The following bus that is part of the **bulk electric system** locations are recommended:

- electrically distant buses that are part of the **bulk electric system** or electrically distant from other **disturbance monitoring equipment** devices;
- voltage sensitive areas;
- cohesive load and generation zones;
- buses that are part of the **bulk electric system** with a relatively high number of incident transmission circuits
- buses that are part of the **bulk electric system** with **reactive power** devices; and
- major facilities interconnecting outside the area of the **legal owner** of a **transmission facility**.

Step 9 The list of monitored buses that are part of the **bulk electric system** for sequence of events recording and **fault** recording data for Requirement R1 is the aggregate of the buses that are part of the **bulk electric system** determined in Steps 7 and 8.

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Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[2]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[2] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.