ElectraNet

Substation Automation System

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This functional requirements document is in line with the organisation's 1-09-ACS-03 Substation SCADA and Automation Asset Class Strategy

Contents

1. Definitions

In this document the following words and expressions will have the following meanings:

Item	Meaning
AC	Alternating Current
AEMO	Australian Energy Market Operator
BCU	Bay Control Unit
BUCC	Back up Control Centre
CT	Current Transformer
DC	Direct Current
DNP3	Distributed Network Protocol
DNSP	Distribution Network Service Provider
EMS	Energy Management System
FBD	Function Block Diagram
FMEA	Failure Modes and Effects Analysis
FSC	Field Service Continuous, electrical junction box used for construction
GIS	Gas Insulated Switchgear
HMI	Human Machine Interface
HV	High Voltage
I/O	Input/output
IED	Intelligent Electronic Device
IP	Internet Protocol
LAN	Local Area Network
LV	Low Voltage
LVAC	Low Voltage Alternate Current
MTBF	Mean Time between Failure
MTTF	Mean Time to Failure
MTTR	Mean Time to Repair
OLTC	On-Load Tap Changer
NER	National Electricity Rules
NTP	Network Time Protocol

Item	Meaning
PLC	Programmable Logic Controller
PSDCS	Power System Data Communication Standard
RTU	Remote Terminal Unit
SAP	Systems, Applications and Products, a software application used by ElectraNet for asset management functions
SAS	Substation Automation System
SCADA	Supervisory Control and Data Acquisition
SMSC	System Monitoring and Switching Centre
SVC	Static Var Compensator
third party IUSA	Has the same meaning as defined in the National Electricity Rules
VT	Voltage Transformer
WAN	Wide Area Network

2. Purpose

This document details the common functional requirements for ElectraNet's Substation Automation System.

3. Scope

This document defines the common functional requirements for the Substation Automation Systems (SAS) applied to ElectraNet's 275 kV, 132 kV and 66 kV transmission network assets. The detailed requirements for specific Substation Automation System functions are detailed within the documents 1-09-FR-22 Substation SCADA System and 1-09-FR-23 Operator Control Interface. The setting of Substation Automation system IEDs is defined within 1-09-AG-02 Protection and Control Setting Application Guide

4. Referenced Documents

The table below lists applicable legislations, standards, referenced documents:

Legislation	
NER	National Electricity Rules
AEMO PSDCS	AEMO Power System Data Communication Standard
SAEA	Electricity Act 1996 (SA)
TC/08	Electricity Transmission Code
International Standards	
IEEE	C37.1-2007 IEEE Standard for SCADA and automation systems
ElectraNet's Documentation	
1-09-ACS-01	Protection System – Digital
1-09-FR-09	Protection Signalling and Intertripping
1-09-FR-14	Switchgear Interlocking
1-09-FR-21	Time Synchronisation
1-09-FR-22	Substation SCADA System
1-09-FR-23	Operator Control Interface
1-09-FR-26	Cubicles and Panels
1-09-FR-26	Circuitry
1-09-FR-28	Protection and Automation - Equipment Hardware and Software
1-09-AG-02	Protection and Control Setting
1-10-ADM-20	Internet Protocol Network Equipment

5. Functional Requirements

The SAS refers to an integrated system of Intelligent Electronic Devices (IEDs) in a substation providing remote monitoring, supervisory control, automatic control and remote engineering access of the substation assets necessary for the management of the electricity transmission network.

This document describes the functional requirements of the SAS but does not include the specific protection and protection related components described in the document 1-09-FR-01 - Protection Common Functional Requirements and Operational Technology Systems, described in 1-10-ADM-20-IP/MPLS Network Equipment.

5.1 Safety (and Environmental) Requirements

SAS are classified, by ElectraNet, as safety critical systems. They must be designed such that the failure of a single system component does not result in the loss of remote monitoring, control and management of the complete or multiple parts of a substation.

5.2 Planning and Design Requirements

5.2.1 General Requirement

5.2.1.1 SAS Philosophy

a) The SAS design must meet the necessary operational, maintenance, asset management and regulatory requirements for the remote monitoring, control and access of the substations assets in accordance with ElectraNet's obligations as Transmission Network Service Provider. These are described in the NER and 1-09-FR-22 Substation SCADA System.

b) The SAS must carry out the acquisition of all the necessary indications, alarms, controls and measurements associated with the various assets in the substation and remote systems using variety of industry standard physical interfaces and communication protocols.

c) The SAS design must comply with the performance requirements of ElectraNet's Asset management system described in this document and that of NER in accordance with AEMO's PSDCS.

d) The SAS design must be equipped with the state of the art processing and communication technologies as well as legacy systems support to acquire, exchange and integrate the data associated with the various primary and secondary assets of the substation, in its ultimate layout. It must achieve it without any deterioration of the required performance levels over its projected useful life.

e) The SAS design must be efficient and scalable to allow the expansion of the system over its projected useful life with minimal impact on the in-service system components.

f) The SAS architecture design must be segregated into the Station Level and Bay Level to maintain the life cycle of the Station and Bay level

components independent of each other across the life of the substation. It must be achieved by the use of open standard communication protocols in the devices at each level.

g) The SAS devices described in this document, other than those described in 1-09--FR-01 Protection Common Functional Requirements, must be physically segregated from the later to provide complete integrity of the protection systems.

h) One SAS must manage all the various voltage levels within a substation at any site with the exception of site specific requirement by ElectraNet.

5.2.1.2 Equipment Technology

ElectraNet's SAS must be established utilising microprocessor based equipment that is capable of providing integrated functionality, a high degree of self-supervision, event recording and information exchange via communication channels. The requirements for equipment hardware platforms are specified within 1-09-FR-28 Protection and Automation - Equipment Hardware and Software.

5.2.2 Supervisory Control Points

a) The supervisory control of the primary plant to isolate or energise a piece of substation equipment or circuit must be performed only via remote control facilities in the substation control room HMI (computer based or mimic control panels) or SCADA system at SMSC/BUCC.

b) The provision of supervisory controls must not be implemented in the proximity of the primary plant unless plant risk assessment to do so with appropriate operating procedure is approved by ElectraNet.

c) Any control provisions in the vicinity of the primary plant must be for use during maintenance while the plant is isolated.

d) The design must allow for the concurrent availability of supervisory controls from remote SCADA at SMSC/BUCC and substation-local HMI at any given of time.

e) The SAS must allow the monitoring and control of the complete substation from any control building within the substation

5.2.3 SAS Elements

The SAS design must be segregated into the following two levels:

a) Station Level; and

b) Bay Level.

5.2.3.1 Station Level

The Station level SAS devices must collect substation indications, status, measurements and controls from bay level devices to provide remote control, monitoring and engineering access of substation assets via the substation control room, ElectraNet's System Monitoring & Switching Centre (SMSC), corporate IT network and third party facilities (where applicable). The main devices at Station level must include:

a) Substation SCADA Gateway;

b) Data Concentrator;

c) HMI; and

d) Remote engineering access Controller.

5.2.3.1.1 Substation SCADA Gateway

a) The Substation SCADA Gateway, sometimes referred to as Substation RTU, exchanges data and controls with the Bay/Process level devices. It then processes and exchanges it with Substation local HMI, SCADA/EMS system at SMSC and BUCC and third parties' SCADA systems (where applicable).

b) It must use a variety of industry-standard communication interfaces and protocols to exchange data and control with the afore-mentioned systems. These are described in 1-09-FR-22 Substation SCADA System

c) Two SCADA Gateways must be provided in the substation to provide higher availability required for operational purposes and meet statutory obligations under the NER.

d) The Substation SCADA Gateway must also perform station wide plant interlocking for the motorised/solenoid type switchgear and other primary equipment in the substation to provide safe control from remote and the plant local control panel.

e) ElectraNet's SCADA/EMS system at SMSC/BUCC must act as an intervening facility under AEMO's PSDCS to exchange the data of ElectraNet's or third party transmission network user facilities with AEMO.

f) The SCADA Gateways in ElectraNet's substation must not be used to exchange DNSPs' or third party transmission network users' facility data with AEMO.

5.2.3.1.2 Data Concentrator

a) Data concentrator shall exchange data and controls from substation IEDs, other SCADA masters in the substation and/or third party facilities. It must process the acquired afore-mentioned day and exchange it with the substation SCADA Gateway.

b) Data Concentrator shall be required in exceptional cases where there is a limited capability of the substation SCADA Gateway to communicate with the legacy or proprietary system devices.

c) The Bay Control Unit may perform Data concentrator function for any new bay level devices with legacy/proprietary interface where they are not able to communicate directly with the SCADA Gateway(s).

5.2.3.1.3 Human Machine Interface (HMI)

It must perform the following:

a) Provide local monitoring and control of the complete substation from the substation control room.

b) Consist of computer-based system on control desk with keyboard, mouse, two display monitors and a printer, referred to as local HMI.

c) The HMI system must allow the Operators to independently monitor and control the substation from any control building while sharing the same alarm management, sequence of events and archiving system.

d) Use off-the-shelf software providing the substation status, alarms and control provisions via graphics on an intuitive and user-friendly video display. The software must be maintainable over the projected useful life of the HMI system.

e) Provide an alarm management system to acknowledge and clear any substation alarms and provides a log of all the substation events including operator actions from the HMI.

f) Provide archiving of the Sequence of Events and System events and measurements for subsequent retrieval for post fault analysis.

g) Provide a read only access from corporate IT network to assist in fault investigations and corrective maintenance. Running remote access HMI application must be seamless to the HMI Operator in the substation control room.

h) A dedicated supervisory control must be provided for each circuit breaker in the control room independent of any of SAS devices.

5.2.3.1.4 Remote engineering access Controller

Remote engineering access Controller must enable remote access to the substation IEDs for remote configuration, access, and data retrieval. The Controller must access the relays via the substation IP based LAN in accordance with the Operational Technology Systems, described in 1-10-ADM-20 Internet Protocol Network Equipment.

5.2.3.2 Bay Level

The Bay/Process level devices must collect associated inputs and controls of the various substation assets via hardwired interface. They then process and exchange those inputs and controls with the Substation SCADA Gateway for the purpose of remote monitoring and control of the substation.

The main devices at Bay/Process level must include:

a) BCU;

b) Protection and Special Control IEDs; and

c) Condition Monitors and miscellaneous devices.

5.2.3.2.1 Bay Control Unit

It must:

d) Collect the hardwired I/O signals from the primary and secondary system assets of the associated bay and exchange them with the Substation SCADA Gateway using industry standard communication interfaces and protocols;

e) Calculate the station metering measurements using CT and VT inputs with the required accuracy and communicate them to the SCADA Gateway;

f) Be provided on per substation Bay basis in order to achieve the desired system availability described in Section 5.1 above. The design must assess it in the case of partially-populated substation bays where substation is not built to its ultimate layout; and

g) Collect the non-bay specific miscellaneous I/Os. A Miscellaneous Bay Control unit(s) must be provided in each control building.

Bay: A Bay normally consist of a circuit breaker and its associated equipment such as Isolators, Current transformers, earth switches etc.

5.2.3.2.2 Protection and Special Control IEDs

These IEDs are dedicated for automatic power system related functions such as protection, automatic reclosing, synch check, system synchronising, automatic voltage regulation, automatic switching of reactive plant, point on wave, wide area control, synchro phasors etc.

They make part of the SAS but are described separately in 1-09-FR-01 – Protection Common Functional Requirements. These devices exchange data and control either with the SCADA Gateways or data concentrators via a communication protocol or hardwired interface to the peripheral I/O Units.

5.2.3.2.3 Condition Monitors and miscellaneous devices

These IEDs are dedicated for condition monitoring or other miscellaneous applications in the substation and will be subjected to site specific requirements.

5.2.3.3 Communication Systems

a) The SAS devices must communicate with each other within the substation and remote system via the substation IP based LAN and WAN infrastructure in accordance with the with the Operational Technology System Systems, described in 1-10-ADM-20 Internet Protocol Network Equipment.

b) The SAS must make use of the state-of-the-art communication technologies and protocols while replacing or augmenting any new assets in the substation.

c) The SAS devices must exchange data and controls with each other via DNP3 protocol.

d) The devices must exchange data and control with each other via IEC 61850 MMS or Modbus communication protocols for site-specific requirements as exception.

e) Use of legacy and customised technology and communication protocols must be considered as exception only where their technical and economic feasibility clearly outweigh the costs and risks associated with the current standards option. The legacy systems may include serial communications, outdated communication protocols and hardwired I/O interfaces to exchange signals via the Bay level devices viz, Protection IEDs, Control IEDs, and Condition Monitors etc.

f) The SAS must be able to communicate with the remote SCADA systems at SMSC/BUCC, other substations and third parties facilities over private or public telecommunication network while maintaining the reliability and security of the data.

5.2.4 SAS Key Functions

The SAS must perform the following key functions for the remote control and monitoring of the substation:

5.2.4.1 Measurements

The SAS must provide the following measurements:

a) Energy flows such as Active Power, Reactive Power, Apparent Power through the line exits, transformers, capacitor, reactors, SVCs etc. Auxiliary LVAC systems energy flows shall be provided only if they are significant enough to adversely affect the required performance of Power system Network applications in SCADA/EMS system;

b) HV, frequency and power factor;

c) Transformer tap positions;

d) Set points for automatic switching schemes; and

e) Condition monitoring of auxiliary systems such as:

(i) Transformer oil and winding temperature;

(ii) Transformer dissolved gas levels;

(iii) Substation Control room(s) temperature; and

(iv) Diesel generator fuel level.

The desired performance criteria for latency, dead bands, accuracy, availability and engineering units of various types of measurements are described in 1-09-FR-22 Substation SCADA System.

5.2.4.2 Status monitoring

The SAS must provide the status of the following:

a) Open and close status of HV circuit breakers, reclosers, disconnectors, earthing switches using the plant auxiliary contacts. LV systems and Auxiliary transformers related switchgear status must only be provided if specified explicitly in the project contract specifications;

b) Setting groups of the protection relays described in 1-09-FR-01 – Protection Common Functional Requirements;

c) Armed and Disarmed status of automatic control schemes; and

d) Health of the SAS devices and communication equipment.

5.2.4.3 Control

a) Selecting, Opening and closing of HV circuit breakers, motorised disconnectors and earthing switches;

b) Safe operation of the circuit breakers, motorised disconnectors and earthing switches via Station wide interlocking;

c) Tap change control for OLTCs;

d) Arming/Disarming of Automatic control schemes;

e) Switching Protection relays setting group;

f) Dispatching Set points for Automatic Control schemes; and

g) Dispatching Set points for Generators (where applicable).

5.2.4.4 Alarming

a) The SAS must provide the alarm for all the adverse conditions associated with primary and secondary substation assets which may represent a risk to substation integrity and system security.

b) It must include the abnormal or faulty conditions of the primary plant, infrastructure, auxiliary and secondary systems:

(i) HV Circuit breakers, CTs, VTs;

(ii) Power Transformers, Capacitor banks, Reactors, SVCs;

(iii) Cables;

(iv) GIS;

(v) Protection operation;

(vi) SAS devices and Communications;

(vii) Auxiliary AC and DC distribution;

(viii) Auxiliary AC and DC supply systems;

(ix) Fire and Security System;

(x) Condition monitors and Disturbance recorders;

(xi) Power Quality Meters;

(xii) Revenue Meters; and

(xiii) Site-specific systems.

c) The status, alarms, measurements and controls associated with a non-standard / uncommon applications viz. Battery Energy Storage Systems, SVCs, FSCs, Synchronous Condensers, and Power System Integrity Protection Scheme etc. must be provided according the equipment vendor and site specific operational requirements.

d) The detailed physical interface and functional/performance requirements of measurements, status monitoring, controls and alarms are described in the document 1-09-FR-22 Substation SCADA System and 1-09-FR-28 Protection and Automation - Equipment Hardware and Software.

5.2.4.5 Time synchronisation

a) The SAS must provide a Global Position Satellite based Clock System in each Control building to synchronise all the IEDs in the substation to South Australian local time.

b) The time synchronisation system must enable all the IEDs to store and report the status, alarms, events and disturbance records in the IEDs, SCADA/EMS and HMI system in the local time with resolution and accuracy of 1ms.

c) The GPS clock must have multiple channels to provide modulated and unmodulated IRIG-B time signals as well NTP over Ethernet.

d) The time synchronisation system must make use of repeaters within the Control building should the aggregated impedance of all the IEDs deteriorates the performance of the time synchronisation system.

e) The detailed requirements of time synchronisation are described in the document 1-09-FR-21 Time Synchronisation

5.2.4.6 Programmed logic functions

The SAS must perform the following calculations for the safe operation and improved alarm performance:

a) Station wide Plant Interlocking; and

b) Grouping / Calculation of alarms and indications.

5.2.4.6.1 Station wide Plant Interlocking

a) The SAS must provide the station wide plant interlocking to ensure safe switching operations to be carried out in the aspect of personnel safety and system security.

b) The interlocking schemes must be implemented to ensure that all switchgears are operated only in the intended sequence.

c) It must be implemented in the SCADA Gateways(s) where the status, indications and alarms will be available to use in the interlocking. It must be achieved by means of PLC application in the SCADA Gateways using IEC61131-1 programming language preferably using FBD.

d) All the remote supervisory controls from the substation HMI and SCADA/EMS System at SMSC/BUCC, must be processed within the SCADA Gateway for interlocking purposes the SCADA Gateway issues the control command to the plant via Bay level devices.

e) SCADA Gateway must enable control on per plant basis, in the respective BCUs, for use in the plant control circuit to enable safe supervisory control of from the plant's local control panel, where such control is made available.

f) The design must ensure a failsafe degradation of the interlocking functions should one or more inputs become faulty or unavailable.

g) The detailed Interlocking requirements are described in the document 1-09-FR-14 Switchgear Interlocking.

5.2.4.6.2 Grouping / Calculation of alarms and indications

The SAS must perform the calculations to create grouped or derived alarms for reporting to the local HMI, SCADA/EMS or third party SCADA systems. It must comprise of:

a) Grouping multiple signals such that any one of them will raise the grouped indication/alarm;

b) Derive alarms where the alarms require some masking under certain conditions or status of the substation primary or secondary assets; and

c) The design must ensure a failsafe degradation of the derived/group alarms should one or more individual alarms/indications become faulty or unavailable.

SAS Station level and Bay level devices, other than those specified in 1-09-FR-01 Protection Common Functional Requirements, must not perform any automatic control scheme or function, unless ElectraNet has a site-specific requirement.

5.2.4.7 Ancillary services

a) The SAS must include provisions for the configuration, file transfer, log and data capture, and diagnostic observation of the SAS devices from the engineering workstation for substation local or remote engineering access via ElectraNet's corporate IT network.

b) Although these services would often involve movement of large blocks of data as well as interaction with SAS devices, they must not adversely affect the required performance and security of critical real time operational services on SAS devices (including protection devices).

5.2.5 Security requirements

The SAS must ensure the following:

a) Access control: Controlled access to selected devices, information or both to protect against unauthorised interrogation of the device or information;

b) Use control: Control use of selected devices, information or both to protect against unauthorised operation of the device or use of information;

c) Data integrity: Integrity of data on selected communication channels to protect against unauthorised changes;

d) Data confidentiality: Confidentiality of data on selected communication channels to protect against eavesdropping;

e) Restrict data flow: Restrict the flow of data on communication channels to protect against the publication of information to unauthorised sources;

f) Timely response to event: Respond to security violations by notifying the proper authority, reporting needed forensic evidence of the violation, and automatically taking timely corrective action in mission critical or safety critical situations; and

g) Network resource availability: Ensure the availability of all network resources to protect against denial of service attacks.

These requirements must be implemented in conjunction with the requirements of Operational Technology Systems, described in 1-10-ADM-20 Internet Protocol Network Equipment.

It must include the physical security including physical access to the automation system network and equipment, but also includes securing network equipment and cables. Electronic security may include items such as encryption, network intrusion detection, and authentication, firewalls, and IED access detection to establish an electronic perimeter of the system.

5.2.6 Characteristics

5.2.6.1 Availability

Station Level: Higher availability must be considered in the Station level design by providing adequate redundancy in the system components used for interlocking and data exchange with the Bay level devices and Network Control centres.

Bay Level: The failure of a system component at this level should not render the remote monitoring and control of overall substation unavailable via the other healthy system components. To cater for the failure of bay control unit, a supervisory hardwired trip and close control with back indications must be provided for each breaker on the associated protection panel independent of the Protection and other SAS devices.

5.2.6.2 Expandability

a) The SAS design must be easily expandable to add new points and/or functions, or both while connecting new SAS devices for new applications or substation augmentation during its projected life in the ultimate layout of the substation.

b) The SAS design must allow seamless expansion or with a minimal downtime, preferably in the order of 5-10 minutes.

c) The SAS design expandability must not result in the degradation of the required performance of any SAS element or function at any given time

d) The expandability of the SAS must be applicable to the following elements:

   (i) Physical space;

   (ii) Power supply capacity;

   (iii) Processor throughput and number of processors;

   (iv) Memory capacity of all types;

   (v) Point limits of hardware, software, or protocol;

   (vi) Communication bus length, loading, and traffic;

   (vii) Program routines, addresses, labels; and

   (viii) Communications buffers and scan times.

5.2.7 Security of Operation

a) The SAS design must be able to recognize an inappropriate or undesirable operation or condition in such a fashion that causes an appropriate alarm, a non-operation, or both.

b) The SAS devices must use both a select-before-execute user interface sequence and a checkback-before-operate communication sequence for control operations.

5.2.8 Diagnostics

The repair times following hardware or software failures can be minimized if the system provides good diagnostic tools. The diagnostic tools must be designed with the following functionality:

a) Defining failure inside or outside the system;

b) Localizing failure inside the system and to a particular device;

c) Remote operation; and

d) Highly effective in minimising the repair/downtime times of hardware and software failures.

5.3 Constructability Requirements

The Substation Automation System must be designed with the following functionality:

a) Each bay level device must be designed such that its input / output capability is expandable. The preferred method of expansion is through the addition of modular input / output boards;

b) The Substation Automation System design must allow the space for ultimate capacity of the expansion of the system in adjacent panels for Bay Control Units and in the Control Building;

c) Hardware and software requirements as defined within 1-09-FR-28 Protection and Automation - Equipment Hardware and Software;

d) Build requirements as defined within 1-09-FR-26 Cubicles and Panels;

e) Circuitry and connections requirements as defined within 1-09-FR-27 Circuitry;

f) Mimic panel or soft push buttons on the front facia of the Bay Control Unit must not be provided or used to execute controls to the switchgear or other assets; and

g) All testing connection points and isolation facilities must be provided at the front of protection and control panels with clear labels.

5.4 Maintainability Requirements

Substation Automation systems must be designed with the maintenance facilities described below:

a) Each device must be equipped with self-monitoring and diagnostic capabilities to minimise hidden failures;

b) The Bay Control Units should be of the modular design which allows the replacement of the defective module only;

c) Where equipment incorporates firmware, a unique number, traceable to the release of the firmware and the version of the system to which it pertains, must be clearly marked on the component, or be available from the informative interface, as well as being documented in the instruction manual;

d) Maintenance aids such as printed wiring extension boards, jumper leads and other special tools must be provided;

e) Full facilities and range of adjustment must be provided to allow the calibration of the equipment to be maintained over its design life, whilst installed on site;

f) Each device, which is in service, must be capable of being safely isolated from the rest of secondary system without the need for primary system outages, specialist tools and knowledge;

g) If the device, which is to be isolated, is connected to other device(s) to form a protection or control scheme (e.g. feeder protection), the isolation must be conditioned with the isolation status of the remotely connected device(s);

h) Each device must be capable of being tested by analogue and digital injections from external test set after being isolated from the rest of secondary system. This requirement is also extended to the ability of capturing communication messages to the substation automation system; and

i) If a device becomes defective, the failed equipment must be capable of being removed and replaced without primary system outages.

5.5 Operability Requirements

The Substation Automation system must be designed with the following functionality:

a) It must provide alarms, indications and measurements to the operators and maintenance personnel in an unambiguous fashion to perform the required operational and maintenance activities. It should allow the controls to be securely executed in a two-step process avoiding inadvertent execution by a mouse click touching without pushing or leaning;

b) The design must be ergonomic as far as practically possible without any adverse impact on their physical health and safety of the personnel using the system;

c) The system must degrade in fail-safe manner in case of defect in any of the system component and must provide sufficient unambiguous information to the remote and local personnel related to the unavailability and defect; and

d) The SAS devices must not mal-operate during primary equipment energisation or de-energisation.

5.6 Availability Requirements

The SAS design must comply with the availability requirements listed in 1-09-ACS-03 Substation SCADA and Automation Asset Class Strategy. The SAS supplier must clearly state the Mean Time between Failure (MTBF) and Mean Time to Repair (MTTR) for SAS devices and system.

5.7 Reliability Requirements

a) The SAS design must comply with the availability requirements listed in 1-09-ACS-03 Substation SCADA and Automation Asset Class Strategy.

b) The SAS supplier must clearly state the Mean Time to Failure (MTTF) for the devices and system. The failure modes of equipment and the effects of these failures must be formally analysed by the supplier. The results of these FMEA must be made available for review upon request.

c) Failure distribution vs. time data for equipment while in the possession of the supplier, and for those field units for which data are available from the users, must be made available upon request.

d) Manufactured and/or supplier-procured parts and components that can cause a critical or major system failure are subject to these requirements described above. When these values are not within acceptable limits, redundant systems and/or components must be utilised.

5.8 Testing and Validation Requirements

Each secondary system device must comply with the requirement listed in 1-09-FR-28 Protection and Automation - Equipment Hardware and Software.

6. SAP Data Capture Requirements

The following information on each of the Station level and field level devices are required to be captured in SAP or relevant software database:

a) Device functional location;

b) Device model and series number;

c) Firmware version that has been deployed in service;

d) Test and verification results; and

e) Device configurations.

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