SMART GRID INTEROPERABILITY PANEL

Basic Application Profile for Distribution Feeder Measurement based on the IEC 61850 Standard

A Testing Profile Developed by the Smart Grid Interoperability Panel

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About the Smart Grid Interoperability Panel

The Smart Grid Interoperability Panel (SGIP) is a public-private non-profit collaborative working to identify requirements for interoperability and technical standards. SGIP members work together to accelerate interoperability, testing and certification so that efficient, secure electrical power can reliably maintain and increase standards of living around the world. Members also have privileged access to the collected knowledge and expertise of all the domains in the Grid Modernization ecosystem. Visit **www.sgip.org**.

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1 Introduction

IEC 61850 represents an extensive set of standards including conformance testing and certification. Conformance testing is aimed at determining whether a product complies with the standard but does not guarantee interoperability between devices of different manufacturers. To address the challenge of multi-vendor interoperability within the context of IEC 61850, additional constraints and definitions are needed.

One approach to developing such constraints is the concept of Profiles. A Profile is a description of a well-defined subset of the standard that has been agreed upon by a user community, testing authority or standards body. The subset may refer to mandatory and optional implementation of a subset of supported data types, logical nodes, logical node elements, services and other aspects of the overall standard. The specification and use of Profiles allows the interoperability gap to be narrowed by reducing the degrees of freedom of implementation flexibility in the context of interest by the device supplier, implementer and system owner. Although there are multiple profile types, the most appealing and arguable the most valuable is the Application Profile.

1.1 Purpose

The purpose of this document is to define a Basic Application Profile (BAP) for measurement of an electrical distribution feeder circuit. The BAP identifies a subset of functionality defined by the IEC 61850 standards in order to facilitate multi-vendor interoperability. It is focused on the function of measurement of and electrical distribution feeder circuit and not intended to directly define device requirements. It is anticipated that an individual BAP will not cover all functionality within a single device or system component within an automation system and that utilities may utilize multiple BAPs to define these device level requirements based on the devices defined functionality.

2 Use Cases

The use cases outlined in this section were selected in order to elicit a thorough and useful set of requirements. As such, the use of the guidance contained within this document is intended to also be suitable for other use cases where feeder measurement data may be communicated such as those involving microgrids or Distributed Energy Resources (DER) integration.

2.1 Supervisory Control and Data Acquisition (SCADA)

2.1.1 Narrative

In this application, an Intelligent Electronic Device (IED) providing monitoring and measurement capabilities, referred to as a Monitoring Device in this use case, is installed by the utility within its electrical distribution system. These capabilities may be provided by a standalone monitoring and measurement IED or as part of a multi-function IED such as a protection relay. This IED provides sensor functionality by monitoring current and voltage inputs associated with the head end of a feeder within one of the utility's distribution substations. This IED then provides this directly measured data, or data which is computed from it, to one or more SCADA master stations via the utility's communication network as illustrated in Figure 1.

Data within the SCADA master station may be utilized by the power system operator for real-time monitoring and control and outage restoration. The SCADA master station may also be supporting the utility's larger Distribution Management System (DMS) functionality and/or other operation applications including Advanced Distribution Automation (DA), Outage Management, Volt/VAR management, or Conservation Voltage Reduction (CVR).

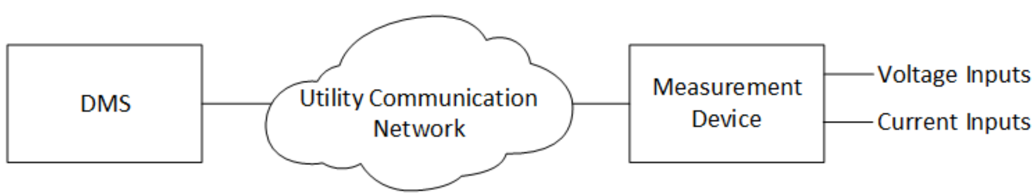

Figure 1- Use case diagram for Supervisory Control and Data Acquisition (SCADA)

It is important to note that because the focus on the exchange of feeder measurement data, the use of this document is not intended to be constrained only to cases where a utility architecture aligns with the architecture represented in Figure 1. Examples of these cases would include instances where the measurement device might be deployed downstream on the feeder rather than the head end of the feeder or where a substation gateway might be utilized to aggregate data from multiple measurement devices within a substation and interface the utility's SCADA master station.

2.1.2 Assumption

- Current and Voltage inputs into the measurement device are not part of this use case
- The Measurement Device has been configured to provide the required data to the SCADA master station
- The SCADA master station has been configured to retrieve the required data from the Measurement Device

2.1.3 Preconditions

- The internal clocks of the SCADA Master Station and the IED have been synchronized to a local precision time source.

2.1.4 Actors

Name	Role Description
Measurement Device	An Intelligent Electronic Device (IED) which monitors and measures grid conditions via current and voltage inputs.
Distribution Management System (DMS)	Retrieves data from Measurement Device and makes this data available to system operator(s) or operational applications.
DMS Operator	Human user of the DMS whose role is to monitor the operational status of the power system and take action, if necessary.
Operational Application	Applications employed by utilities which support real-time operations of the electric power system. These applications may be monitoring only with output utilized by system operators for decision making or may be closed-loop and take direct control actions based on observed power system data.

2.1.5 Operations

Name	Service or information provided
Data sampling & estimation	The IED measures voltage and current inputs and provides a digitized sample of this data. The IED also calculates/estimates additional data points

	(e.g. kwh, watts, VARs, etc.).
Data request	The SCADA master initiates an on-demand request for data from the IED
Data sending	The IED sends data requested by the SCADA master applications

2.1.6 Basic Flow

Data Originating and Sending

Use Case Step	Description
Step 1	Measurement Device monitors current and voltage inputs, computes associated data, and populates internal database
Step 2	Measurement Device makes specific internal database elements available within the communication interface based on predefined device configuration
Step 3	Measurement Device determines status of logical connection to DMS
Step 4	Measurement Device sends data to the DMS

Data Receipt and Processing

Use Case Step	Description
Step 1	DMS receives data from the Measurement Device
Step 2	DMS populates/updates the individual elements of the DMS database associated with the Measurement Device based on a predefined configuration
Step 3	DMS makes the data from the DMS database, linked to the data received from the Measurement Device, available for the DMS Operator
Step 3 (Alternate)	DMS makes the data from the DMS database, linked to the data received from the Measurement Device, available for operational applications (Advanced DA, Outage Management, Volt/VAR Management, CVR)

2.1.7 Constraints

The following constraints and special needs have been identified to further define the requirements associated with the applications outlines in Section 2.1.1.

2.1.7.1 Data Update Rates and Time Synchronization Accuracy

Data supporting SCADA applications can be communicated in a variety of update rates. The following table summarizes typical applications which may utilize the feeder measurement data from within SCADA master station and their associated transmission rates and time synchronization accuracy requirements.

Application Type	Minimum Update Rate	Time synchronization accuracy
SCADA (Typical)	4 seconds	100ms
Advanced DA	4 seconds	100ms
Outage Management	30 seconds	1 second
Volt/VAR Management	60 seconds	1 second
CVR	60 seconds	1 second

It is important to note that this table is intended to identify minimum performance criteria for these applications in general. It is anticipated that for some local applications such as recloser control or substation based centralized protection, these criteria will be more stringent.

2.1.7.2 Data Representation

This basic application profile requires the measurement of three phase quantities. It is important to note that the measurement of three phase voltages is dependent on the fundamental configuration of the feeder to be measured. Feeders can be grounded or ungrounded (fed by a WYE-Grounded, DELTA or WYE-Ungrounded transformer secondary) and if grounded with or without Neutral conductor. These feeder configurations will determine which MMXU logical node elements are appropriate for voltage measurement.

For ungrounded systems, only Phase-Phase voltage measurements are valid. In a grounded system, Phase-Phase and Phase-Ground voltage measurements are possible. Best distribution system measurement practices suggest that both measurement types be taken but Phase-Ground measurements be utilized as a minimum to facilitate per-phase Volt/VAR management in grounded systems. In a grounded system with neutral conductor, Phase-Phase, Phase-Ground, and Phase-Neutral voltage measurements are possible especially if the neutral and ground are only occasionally bonded together along the feeder. Best distribution system measurement practices suggest that all three measurement types be taken but that Phase-Neutral measurements be utilized as a minimum in this case to facilitate per-phase Volt/VAR management in grounded systems with a neutral conductor. Following these practices allows the implementer to expect what the minimum available data will be for three phase voltage measurement.

2.1.7.3 Data Format

Utilizing both instantaneous and deadbanded measurement values is considered a best practice to support both basic SCADA and Volt/VAR control use cases. For basic SCADA, it is common practice to utilize deadbanded values to minimize data traffic by only communicating a value (usually a voltage) when it changes from the last reported reading by a configured amount. The deadband value is chosen to suit the applications for which the measurement is intended to be used. For applications involving highly localized Volt/VAR control, external controllers will generally have a requirements for an on-demand read of the actual (instantaneous, non-deadbanded) value to facilitate the control objective. For this reason, data elements both deadbanded and instantaneous values are required in this basic application profile to ensure that both of these common use cases are supported.

2.1.7.4 Multiple Applications

Typical utility operations may warrant that communication sessions are active for multiple applications concurrently or temporary ad-hoc connections be supported without interrupting ongoing communications. An example of this would be an IED which may be supporting communication interface for the utility's SCADA master as well as one for a condition monitoring application. In this case, the utility may also need the capability to be able to initiate temporary connections to the IED for maintenance and testing purposes.

2.1.7.5 Loss of Communications

A utility may require that in the event of a loss of communications, events and changes which occur during the outage be reported upon restoration of the communications.

3 Requirements

This section represent a minimum set of requirements and is not intended to constrain vendors from implementing features and functionality beyond that specified.

3.1 Functional Requirements

3.1.1 Informational

REQ ID	Requirement
INF1	Frequency (Hz)

INF2	3-phase voltage-Phase-to-Neutral
INF3	3-phase voltage-Phase-to-Ground
INF4	3-phase voltage- Phase-to-Phase
INF5	3-phase current + neutral (in a 4-wire system)
INF6	Per phase and Total real power
INF7	Per phase and Total reactive power
INF8	Per phase and Total apparent power
INF9	Displacement/fundamental power factor
INF10	Sequence based unbalance (V2/V1 and I2/I1 in 3-wire and 4-wire systems)
INF11	Per phase THD and TDD
INF12	Device health
INF13	Cold Load Pickup

3.1.2 General

REQ ID	Requirement
GEN1	Data quality attributes shall be available for all data
GEN2	All data shall be time stamped at the point of measurement
GEN3	All analog data shall be reported as floating point values
GEN4	All analog data shall be reported as primary values
GEN5	Indication of the current analog value with respect to its operating range shall be provided

3.2 Non-Functional

REQ ID	Requirement
NF1	A minimum of three concurrent communications sessions shall be supported

4 Mapping to IEC-61850

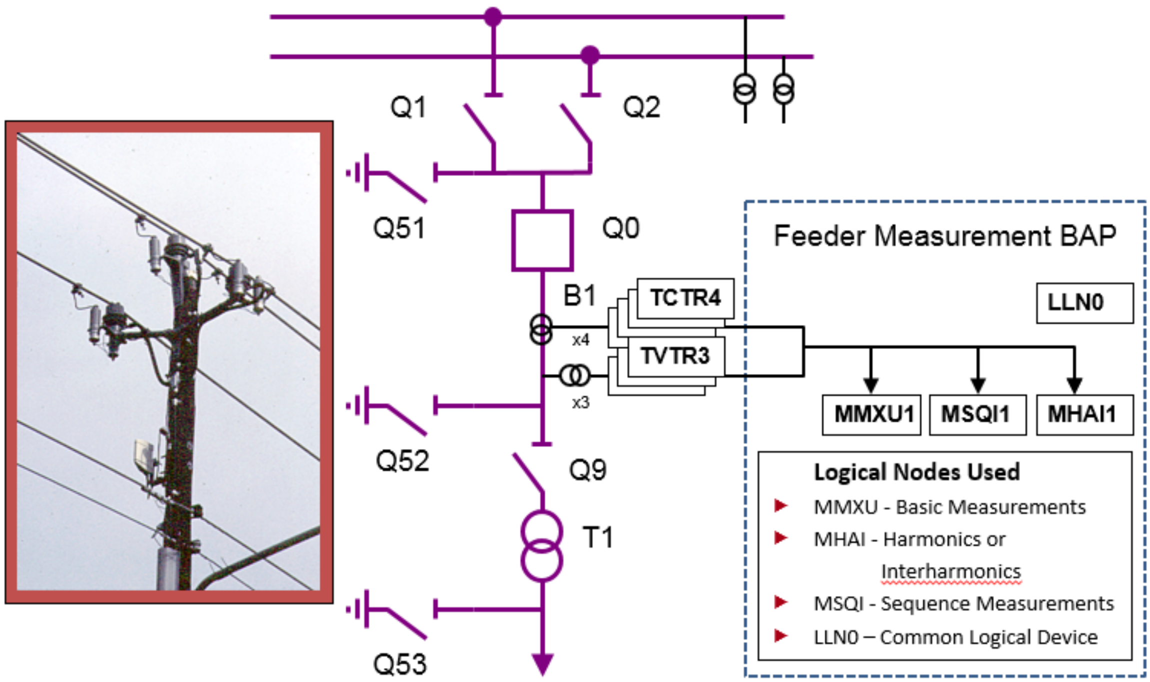

Figure 1 - LN Mapping Example for Distribution Measurement BAP

4.1 Logical Nodes

The following logical nodes, defined in IEC-61850-7-4, Edition 2.0, shall be required.

All measurement data shall be provided in both instantaneous and deadband forms. Instantaneous values shall be updated on each occurrence of a read operation performed by an IEC-61850 client. The deadbanded value (data attribute = mag or cVal) shall be updated to the current instantaneous value (data attribute = instMag or instCVal) when the value has changed according the configuration parameter db as outlined in IEC-61850-7-3.

Data	IEC 61850 Mapping	
	Logical Node	Data Element

Data	IEC 61850 Mapping	
	Logical Node	Data Element
Frequency (Hz)	MMXU	MX.Hz.mag.f
		MX.Hz.instMag.f
		MX.Hz.range
		MX.Hz.q
		MX.Hz.t
3-phase voltage-Phase-to-Neutral (A-N)	MMXU	MX.PNV.phsA.cVal.mag.f
		MX.PNV.phsA.instCVal.mag.f
		MX.PNV.phsA.range
		MX.PNV.phaA.q
		MX.PNV.phaA.t
3-phase voltage-Phase-to-Neutral (B-N)	MMXU	MX.PNV.phsB.cVal.mag.f
		MX.PNV.phsB.instCVal.mag.f
		MX.PNV.phsB.range
		MX.PNV.phaB.q
		MX.PNV.phaB.t
3-phase voltage-Phase-to-Neutral (C-N)	MMXU	MX.PNV.phsC.cVal.mag.f
		MX.PNV.phsC.instCVal.mag.f
		MX.PNV.phsC.range
		MX.PNV.phaC.q
		MX.PNV.phaC.t
3-phase voltage-Phase-to-Ground (A-G)	MMXU	MX.PhV.phsA.cVal.mag.f
		MX.PhV.phsA.instCVal.mag.f
		MX.PhV.phsA.range
		MX.PhV.phaA.q
		MX.PhV.phaA.t
3-phase voltage-Phase-to-Ground (B-G)	MMXU	MX.PhV.phsB.cVal.mag.f
		MX.PhV.phsB.instCVal.mag.f
		MX.PhV.phsB.range
		MX.PhV.phaB.q
		MX.PhV.phaB.t
3-phase voltage-Phase-to-Ground (C-G)	MMXU	MX.PhV.phsC.cVal.mag.f
		MX.PhV.phsC.instCVal.mag.f
		MX.PhV.phsC.range
		MX.PhV.phaC.q
		MX.PhV.phaC.t
3-phase voltage- Phase-to-Phase (A-B)	MMXU	MX.PPV.phsAB.cVal.mag.f

Data	IEC 61850 Mapping	
	Logical Node	Data Element
		MX.PPV.phsAB.instCVal.mag.f
		MX.PhV.phsAB.range
		MX.PhV.phaAB.q
		MX.PhV.phaAB.t
3-phase voltage- Phase-to-Phase (B-C)	MMXU	MX.PPV.phsBC.cVal.mag.f
		MX.PPV.phsBC.instCVal.mag.f
		MX.PhV.phsBC.range
		MX.PhV.phaBC.q
		MX.PhV.phaBC.t
3-phase voltage- Phase-to-Phase (C-A)	MMXU	MX.PPV.phsCA.cVal.mag.f
		MX.PPV.phsCA.instCVal.mag.f
		MX.PhV.phsCA.range
		MX.PhV.phaCA.q
		MX.PhV.phaCA.t
3-phase current (A)	MMXU	MX.A.phsA.cVal.mag.f
		MX.A.phsA.instCVal.mag.f
		MX.A.phsA.range
		MX.A.phaA.q
		MX.A.phaA.t
3-phase current (B)	MMXU	MX.A.phsB.cVal.mag.f
		MX.A.phsB.instCVal.mag.f
		MX.A.phsB.range
		MX.A.phaB.q
		MX.A.phaB.t
3-phase current (C)	MMXU	MX.A.phsC.cVal.mag.f
		MX.A.phsC.instCVal.mag.f
		MX.A.phsC.range
		MX.A.phaC.q
		MX.A.phaC.t
3-phase current (N) (for 4-wire system)	MMXU	MX.A.neut.cVal.mag.f
		MX.A.neut.instCVal.mag.f
		MX.A.neut.range
		MX.A.neut.q
		MX.A.neut.t
Real power: Total	MMXU	MX.TotW.mag.f
		MX.TotW.instMag.f

Data	IEC 61850 Mapping	
	Logical Node	Data Element
		MX.TotW.range
		MX.TotW.q
		MX.TotW.t
Real power: A-phase	MMXU	MX.W.phsA.cVal.mag.f
		MX.W.phsA.instCVal.mag.f
		MX.W.phsA.range
		MX.W.phaA.q
		MX.W.phaA.t
Real power: B-phase	MMXU	MX.W.phsB.cVal.mag.f
		MX.W.phsB.instCVal.mag.f
		MX.W.phsB.range
		MX.W.phaB.q
		MX.W.phaB.t
Real power: C-phase	MMXU	MX.W.phsC.cVal.mag.f
		MX.W.phsC.instCVal.mag.f
		MX.W.phsC.range
		MX.W.phaC.q
		MX.W.phaC.t
Reactive power: Total	MMXU	MX.TotVAr.mag.f
		MX.TotVAr.instMag.f
		MX.TotVAr.range
		MX.TotVAr.q
		MX.TotVAr.t
Reactive power: A-phase	MMXU	MX.VAr.phsA.cVal.mag.f
		MX.VAr.phsA.instCVal.mag.f
		MX.VAr.phsA.range
		MX.VAr.phaA.q
		MX.VAr.phaA.t
Reactive power: B-phase	MMXU	MX.VAr.phsB.cVal.mag.f
		MX.VAr.phsB.instCVal.mag.f
		MX.VAr.phsB.range
		MX.VAr.phaB.q
		MX.VAr.phaB.t
Reactive power: C-phase	MMXU	MX.VAr.phsC.cVal.mag.f
		MX.VAr.phsC.instCVal.mag.f
		MX.VAr.phsC.range

Data	IEC 61850 Mapping	
	Logical Node	Data Element
		MX.VAr.phaC.q
		MX.VAr.phaC.t
Apparent power: Total	MMXU	MX.TotVA.mag.f
		MX.TotVA.instMag.f
		MX.TotVA.range
		MX.TotVA.q
		MX.TotVA.t
Apparent power: A-phase	MMXU	MX.VA.phsA.cVal.mag.f
		MX.VA.phsA.instCVal.mag.f
		MX.VA.phsA.range
		MX.VA.phaA.q
		MX.VA.phaA.t
Apparent power: B-phase	MMXU	MX.VA.phsB.cVal.mag.f
		MX.VA.phsB.instCVal.mag.f
		MX.VA.phsB.range
		MX.VA.phaB.q
		MX.VA.phaB.t
Apparent power: C-phase	MMXU	MX.VA.phsC.cVal.mag.f
		MX.VA.phsC.instCVal.mag.f
		MX.VA.phsC.range
		MX.VA.phaC.q
		MX.VA.phaC.t
Average power factor	MMXU	MX.TotPF.mag.f
		MX.TotPF.instMag.f
		MX.TotPF.range
		MX.TotPF.q
		MX.TotPF.t
Imbalance negative sequence current	MSQI	MX.ImbNgA.mag.f
		MX.ImbNgA.instMag.f
		MX.ImbNgA.range
		MX.ImbNgA.q
		MX.ImbNgA.t
Imbalance negative sequence voltage	MSQI	MX.ImbNgV.mag.f
		MX.ImbNgV.instMag.f
		MX.ImbNgV.range
		MX.ImbNgV.q

Data	IEC 61850 Mapping	
	Logical Node	Data Element
		MX.ImbNgV.t
Per phase THD (A)	MHAI	MX.ThdA.phsA.cVal.mag.f
		MX.ThdA.phsA.instCVal.mag.f
		MX.ThdA.phsA.range
		MX.ThdA.phsA.q
		MX.ThdA.phsA.t
Per phase THD (B)	MHAI	MX.ThdA.phsB.cVal.mag.f
		MX.ThdA.phsB.instCVal.mag.f
		MX.ThdA.phsB.range
		MX.ThdA.phsB.q
		MX.ThdA.phsB.t
Per phase THD (C)	MHAI	MX.ThdA.phsC.cVal.mag.f
		MX.ThdA.phsC.instCVal.mag.f
		MX.ThdA.phsC.range
		MX.ThdA.phsC.q
		MX.ThdA.phsC.t
Per phase TDD (A)	MHAI	MX.TddA.phsA.cVal.mag.f
		MX.TddA.phsA.instCVal.mag.f
		MX.TddA.phsA.range
		MX.TddA.phsA.q
		MX.TddA.phsA.t
Per phase TDD (B)	MHAI	MX.TddA.phsB.cVal.mag.f
		MX.TddA.phsB.instCVal.mag.f
		MX.TddA.phsB.range
		MX.TddA.phsB.q
		MX.TddA.phsB.t
Per phase TDD (C)	MHAI	MX.TddA.phsC.cVal.mag.f
		MX.TddA.phsC.instCVal.mag.f
		MX.TddA.phsC.range
		MX.TddA.phsC.q
		MX.TddA.phsC.t
Device health	LLN0	ST.Health.stVal
		ST.Health.q
		ST.Health.t

4.1.1 Cold Load Pickup (CLP)

An application important for distribution feeder monitoring includes Cold Load Pickup (CLP). CLP refers to the additional current observed on a feeder when energized after an extended outage (roughly an hour or more). There are two components to the phenomenon – current inrush upon energization contributed from transformers, capacitors and other reactive devices, and the higher steady state current demand due to the loss of load diversity (e.g. all HVAC systems out of temperature tolerance wanting to activate all at once). This basic application profile does not require any special consideration for CLP since other required elements of the profile can be configured to record the phenomena and report on it. Typically a measuring system complying with this profile could be configured for CLP by utilizing the reporting features of 61850 to report on changes to feeder current measurements using a deadband configuration to ensure that current measurements are reported quickly during the inrush phase when the current is changing rapidly and slow down reporting to integrity interval only as the inrush dissipates and the current changes more slowly as load diversity is regained. Analysis of the phenomena is an application specific function using the data captured by a device meeting this BAP.

4.2 Services

4.2.1 Data Sets

Services necessary to support data sets shall be implemented in both the client and server. There are several options possible for implementation of data sets; fixed (data sets which are fixed within the device and not changeable), configured (data sets defined at the time of device configuration and represented within the relevant SCL files), dynamically created persistent data sets, and dynamically created non-persistent data sets.

For the purposes of this guidance, the minimum implementation shall be the support of configured data sets (data sets defined at the time of device configuration and represented within the relevant SCL files).

4.2.2 Reporting

Services necessary to support reporting shall be implemented in both the client and server. Buffered reporting (Buffered report control block (BRCB)) shall be utilized for server-initiated transmission of the information models outlined in Section 3.1.1 to the client.

4.2.3 Logging

The implementation of services required to support logging is not required to be complaint to this application profile.

5 Document References

[1] IEC 61850-7-1, Communication networks and systems for power utility automation – Part 7-1: Basic communication structure – Principles and models, Edition 2.0

[2] IEC 61850-7-2, Communication networks and systems for power utility automation – Part 7-2: Basic information and communication structure – Abstract communication service interface (ACSI) , Edition 2.0

[3] IEC 61850-7-3, Communication networks and systems for power utility automation – Part 7-3: Basic communication structure – Common data classes, Edition 2.0

[4] IEC 61850-7-4, Communication networks and systems for power utility automation – Part 7-4: Basic communication structure – Compatible logical node classes and data object classes, Edition 2.0