# TOWARDS OPEN DISTRIBUTED FEEDER AUTOMATION SYSTEMS

Rogério PAULO
Efacec – Portugal
rdpaulo@efacec.com

Rui JORGE
Efacec – Portugal
rdjorge@efacec.com

## *ABSTRACT*

*The paper defines the concept of medium voltage feeder automation systems (DAS) based on distributed intelligence within control areas, supported by the IEC 61850 family of standards.*

*With DAS systems starting to be deployed, transitioning from pilots to industrial application, the authors propose three maturity levels as a means to support planning for industrial deployment.*

*Maturity levels are classified according to functional incorporation, functional distribution, architecture variants, and, management requirements. Higher maturity levels provide increased speed, resilience as well as optimization of QoS and use of resources.*

*Given the relevance of efficient engineering and management for industrial deployment of large scale distributed systems, the authors identify requirements and possible solutions considering (i) configuration, (ii) commissioning and field operations, (iii) version management, and, (iv) operation.*

## INTRODUCTION

Medium voltage feeder automation systems constitute an accelerated developing domain in distribution automation (DA). Currently available or upcoming information-level interoperability standards and core technology, including latest generation IEDs based on high-end processors and communication networks based on fibre infrastructure, Wimax or 4G, provide a high-performing industrial framework to deploy massive distributed intelligence.

Striving to increase overall grid performance and cope with the impact of new generation/demand options, multiple pilot projects have focused on different aspects from self-healing to integration of Distributed Energy Resources (DER[1]), test bedding communication infrastructures and protection and control strategies. Notwithstanding, current industrial practice for automating MV feeders is either non-communication-based (ex: local time/voltage-.based algorithms), local to primary substations (ex: Volt/VAr control), or, hosted at the SCADA/DMS/OMS control centre (CC), using the conventional hierarchical telecontrol infrastructure to access field RTUs (ex: FDIR).

With IP-based communication meeting the technical requirements for client/server (C/S) and peer-to-peer (P2P) data exchange [1,2], IEC 61850 becomes the key standard for open distribution MV feeder automation system (DAS) [3]. Ongoing initiatives such as [4,5,6] will complete the required set of first-level services and information models to support interoperability at information level [7,8,9] for the DA/DER domains.

## Distributed Automation – Key Factors

Distributed autonomous solutions push intelligence to the field and provide benefits when compared to fully centralized automation (CC-based), including speed and resilience (suited autonomous feeder or area schemes instead of complex global schemes), leading to higher grid optimization. The introduction of "smart-assets" (primary equipment with integrated IEDs and digital interface) is also expected to reduce integration and development costs from a grid perspective. Large scale deployment of field-level processors is required in any smart grid scenario (in the hundreds of thousands for an average DSO). Considering current embedded industrial processors a significant amount of available processing capability would hence be readily available.

However, high levels of functional distribution towards such processors are more complex to engineer and manage, namely when area/system-level information or calculations are required at each processing node. For that reason significant functional distribution grid-scale is today perceived as having either higher life-cycle engineering and O&M costs, reduced flexibility, and/or, limited feasible functionality when considering the lifecycle except for specific use cases.

Large scale deployments frequently imply adopting multi-vendor procurement strategies to prevent lock-in, and investment cycles imply that the DAS is expected to exhibit multi-generation technology for years to come. To solve the engineering and management dilemma interoperability is required.

## Engineering and Management – Key Factors

From an engineering and management perspective DAS have four main distinctive features when compared to substation automation (SAS) or similar distributed systems, now mature and heavily employed in the industry for HV/VHV. The first is scale of distribution (in a factor of 10 or more in number of nodes). The second is the widespread physical distribution of nodes without a containment perimeter. The third is that multiple organizations would manage different boundary systems with which information needs to be exchanged (DER/Consumers). The fourth is a higher invariance in types of primary equipment and grid topology.

One implication is that conventional systems engineering methodologies for T&D automation are not fully applicable. Design standardization as well as remote and automated engineering and management [8,9,10] are key options to keep lifecycle engineering costs to a reasonable level. With limited system variance between multiple feeder areas, these approaches have a high benefit/cost ratio at scale. Another implication is the fact that cybersecurity becomes more complex, namely for

1 DER includes DG, Storage, DR and related systems (VPPs).

engineering and management where system performance and status monitoring is combined with modification of software, settings and exchange of security keys.
Engineering and management interoperability is hence a cross-cutting issue that now constitutes one key deterrent for industry-wide application.

## DISTRIBUTED FEEDER AUTOMATION SYSTEMS

In this paper a DAS (fig.1 in annex) is defined as a communications-based system performing MV feeder protection, control, automation and monitoring functions through interoperating IEDs (processing nodes) using P2P and C/S services. A given system may span a single feeder or a set of feeders in a distribution control area and interfaces neighbouring systems through similar information exchange interfaces. Such boundary systems include, depending on system maturity level: (i) CC (grid operational monitoring and control), (ii) AMS (asset identification, condition and performance information), (iii) SAS (protection and control schemes), and, (iv) DER/Consumer systems (protection and control information exchange, including MV-connected DER stations or MV/LV connected virtual power plants). Table 1 identifies key operational functions of the DAS.

**Tab. 1 – Key operational functions considered for the DAS**

| Fun. | Description |
|---|---|
| RCM | Remote control and measurement/monitoring (conventional SCADA) |
| PQ | Power quality monitoring (sags/swells, harmonics, etc.) |
| CMD | Asset condition monitoring and diagnostics, and, asset management-related functions |
| FP | Feeder protection (fault, loading, anti-islanding) |
| FDIR | Fault detection, isolation and restoration |
| VVC | Voltage/VAr control (regulation for voltage profile control, loss minimization, fault prevention) |
| AS | Real-time management of adaptive settings (protection and control coordination) given power flow variations or topology changes. |
| FR | Automatic feeder reconfiguration (preventive or restorative, for loss optimization, balancing, congestion, fault prevention) |
| DC | DER(/DG/DR/VPP) control (technical optimization including also post-fault/disturbance remedial actions) |

Each atomic element of a given function (logical node) may be allocated to any processor (at field level close to the process (FIED) or centrally at the possibly redundant area controller (AC), deployed at the primary substation or other remote location, including the CC)[2]. The most suitable allocation, usage of services and corresponding data flows (logical architecture) depends on available communication subsystem technical and cost performance, available IED technology and required system functions. Higher levels of distribution (increased field-level allocation) provide higher speed and selectivity with more demanding latency requirements. Communication reliability requirements depend on expected level of system performance, but unavailability of data flow channels, IEDs or remote data is locally detectable with IEC 61850. In degraded operating scenarios high-performing functions may be inhibited and system may fall back to less performing secure alternatives.

### System Maturity Levels

Authors classify architectures and functions in three maturity levels. Higher maturity levels provide higher supply reliability, increased feeder usage, increased support for DER, and, faster fault recovery. Higher maturity levels also correspond to higher functional incorporation, sophistication in technology and level of field distribution. Please refer to tab. 2 and 3 in annex for details. Even though a level classification may not constitute an exact fit for all deployment scenarios, such model may be considered for planning different stages of industrial deployment.

## REQUIREMENTS FOR LIFE-CYCLE ENGINEERING AND MANAGEMENT

Towards the so-called "plug-and-play" architectures, engineering and management of such a system of systems in a multi-vendor adaptive environment requires automation and centralization of many related processes. In figure 1 (see annex) an architecture including centralized O&M Support System (OMSS), centralized Engineering Server (ES) and roaming tools is proposed.
Please note that at M0 requirements are rather straightforward to implement since FIEDs do not require a high level of flexibility nor are there significant interactions between them. In such scenarios automating classical RTU engineering and management procedures has been already deployed in successfully in the field for non-IEC 61850 solutions [11]. If for M0 deployments use of IEC 61850 can now be recommended, for M1/M2 deployments, use of standardized engineering methods is critical, since the cost of supporting proprietary solutions would only be attainable by very large utilities. A multi-vendor digital engineering environment based on a single system model across the life cycle, as proposed in [8], provides a solution.

### Configuration Management

Since nodes are expected to become more flexible as maturity levels increase, allowing vendors to target different markets and providing flexibility for users, the configuration process becomes highly relevant. The scope of many configuration settings is local to each node (addresses, services, I/O, information model, logics, etc.) and its variability may be significantly reduced through detailed standardised utility specifications. Others however require flexibility during the life-cycle, being intrinsically tied to the interactions between nodes (data flows, information model, functions and logics) and to changes in the grid itself, particularly when considering higher maturity levels.
Taking the FDIR function as an example[12,13,14,15], at lower maturity levels it may be programmed into the firmware of each FIED, at higher levels an automated configuration mechanism such as [10] is required to automatically cope

2 Grid-wide operation level allocation (CC) is also possible, but considered outside the boundaries of the DAS.

with changes in both the secondary and primary system (equipment and grid topology). This requires the central ES digital configuration repository to model the whole area/system, including the single line, electrical equipment characteristics, communication networks, IEDs, information model, data-flows, logics, etc.
Another example is updating the configuration of operation or area zone applications (SCADA, OMSS, AC or others). This can be highly automated for any maturity level if IEC 61850 self-description services and SCL exchange together with standardized information models are employed.

## Version Management

The distinct item classes to manage at the OMSS are hardware, firmware, configuration settings, cybersecurity keys, and operational settings. Requirements include remote: (i) tracking of IED/system inventory (nameplate, location, etc.), (ii) secure deployment and/or extraction, (iii) historical tracking of versions, and, since some items may be modified remotely or in the field, (iv) coherency validation.
Version management is closely tied to the configuration management process in terms of workflow (approval of settings, system configuration, etc.). At M1 and particularly at M2, configuration interaction outside system and company boundaries (SAS, DER, manufacturer) needs consideration, with the implication that such interfaces also require addressing in processes, information exchange and cybersecurity.
Configuration settings or firmware changes of an online system shall be remote, automated and minimize the impact on system availability. These changes may affect a given area, one IED or part of an IED, with different isolation and restart procedures, and also require verification. This is not only a device-level issue, but a system issue, at higher maturity levels.

## Commissioning and Other Field Operations

Operations such as installing a new recloser or secondary substation, retrofits, equipment replacements or specific maintenance of primary and/or secondary assets shall be carried out with minimum local effort. Roaming mobile tools with direct local access to devices and remote access to the OMMS server can assist field crews during such operations with step-by-step procedures, with personnel adopting a supervisory role.
Key requirements here include automating the following processes: (i) identification and registration of devices into the O&M inventory database, (ii) automatic download of pre-validated firmware, configuration settings and operational settings, (iii) update of SCADA and O&M server database, and, (iv) diagnostics and testing. Of the four steps above, three have been discussed and the third requires other optimization methods, namely (i) validated pre-design, (ii) self-testing/monitoring and (iii) "smart-assets".
To minimize testing of logical items in the field local settings can be pre-designed and pre-tested for given deployment configuration types, templated and then instantiated for each site by entering only a subset of local parameters. Note that for higher maturity levels system-level configuration settings are also included which would imply that the instantiation of templates, which are not globally applicable, require auto-configuration steps.
Self-monitoring and self-testing are functions that can be hosted at any node, significantly reducing the need for user-driven testing during commissioning, maintenance or operation. Examples range from phase sequence verification, ADC precision or measurement coherency checks, to, information structure validation through self-description, version comparison, quality bit checking, dataflow availability and message data structure checks. Introducing primary equipment with built-in digital technology further simplifies procedures by carrying out a significant part of the configuration and verification by the manufacturer at the production facility according to the pre-designed templates of each utility.

## Operation

During operation the OMMS key roles are to (i) ensure RBAC to the distribution area, (ii) host the version management service for all nodes, interacting with the ES and other systems, and, (iii) act as device and system supervisor, all of which are non-operational features.
The supervisory function includes capturing O&M information in near-real time from the DAS nodes including: (i) system operative status (HW status, function and device health checks, data flow status, communication status, operating modes), (ii) power grid information (PQ, Fault reports, SOE, etc), (iii) primary asset CMD information, and, (iv) cybersecurity auditing (security alerts, accesses to IED, configuration changes, operation reports, etc.). At a second level the OMSS is expected to perform higher-level analysis (CBM, function performance, maintenance alerts, behaviour prognosis, maintenance recommendation and root-cause analysis, etc.) and reporting/alerting.

# IEC 61850 STATUS

IEC 61850 provides adequate communication services and data types required for operational functions (C/S, GOOSE, SV, event/data, files, operational settings, controls, quality information, critical cybersecurity, etc.), as well as part of the required online/offline information exchange models (single line, communication networks and devices, FP, RCM, AS, PQ). The SCL format can be applied in several of the configuration exchange interfaces required for DAS. IEC 61850 is currently being enhanced with additional cybersecurity features, specific information models for critical DAS functions (FD, FDIR), new services, including identification and registration, new systems management models/processes, as well as logics integration. Some information models are still not expected to be available soon, but can be designed as utility extensions (equipment and device models and feeder communications constitute examples).
Current status makes M0 and M1 levels attainable today

with proprietary extensions being required mainly for systems management and tool integration through proprietary interfaces. M2 requires additional standardization work when considering automated engineering processes, device flexibility and reconfigurability, systems management, asset management, as well as cybersecurity. Required features for M2 may be integrated without backward compatibility issues.

## CONCLUSION

Open distributed feeder automation systems based on the IEC 61850 family of international standards will enable utilities to attain a very high level of QoS and optimized use of resources. Massively distributed systems add the benefits of speed and resilience and may support fault reconfiguration with virtually no unavailability and prevent failures, while optimizing power flows in active networks.

The drawbacks in engineering and management of multi-vendor, multi-generation, large-scale and multi-level systems can be mitigated by the use of adequate architectures and supporting standards development within this domain.

Such framework also enables long term deployment of evolving distribution area systems with different levels of maturity. Backward compatibility is ensured by information-level international standards that simplify the design of utility standards, minimize testing and enable optimized procurement while providing vendors with a significant and sustainable market.

Although the industry is not yet mature to fully deploy instant "plug-and-play" systems, such concepts can be supported to the level of what is required in a step-by-step evolution towards highly mature distributed automation solutions.

## REFERENCES

[1] IEC TC57, "IEC/TR 61850-90-5: Use of IEC 61850 to transmit synchrophasor information according to IEEE C37.118", IEC, 2012

[2] IEC TC57, "IEC/TS 62351: Data and communications security", IEC, 2007-2013

[3] CEN-CENELEC-ETSI Smart Grid Coordination Group, "Smart Grid Reference Architecture", 2012

[4] IEC, "IEC/TR 61850-80-3: Mapping to web protocols – Requirement analysis and technology assessment", WIP, 2014

[5] IEC, "IEC/TR 61850-90-6: Use of IEC 61850 for distribution automation systems", WIP, 2014

[6] IEC, "IEC 61850-7-420 Ed.2: Distributed energy resources logical nodes", WIP, 2014

[7] G. Huon et. al. "IEC61850 Based Substation Automation Systems - Users Expectations and Stakeholders Interactions", CIGRE 2014, Paris

[8] R. Paulo, "Next Step for IEC 61850: A Unified Power Utility Automation Language - Why and How", CIGRE 2014, Paris

[9] R. Paulo, F. Matos, "A Functionally-integrated Architecture for Online Monitoring and Real-time Diagnostics and Management of Substation Assets as a tool for Optimized Maintenance Management", CIGRE 2014, Paris

[10] R.Paulo, R.Jorge, "Auto-configuration of Multi-vendor Substation Control Systems: The Case for Interlocking", XII STPC, 2014, Rio de Janeiro

[11] F.Campos et. al., "Safe, simple and fast commissioning of smart devices for MV and LV networks using new support tools", CIRED 2015, Lyon

[12] F. Mekic et. al., "Fault Detection Isolation and Restoration on the Feeder (FDIR): Pick Your Technology", CIRED 2011, Frankfurt

[13] E. Coster, "Self Healing Distribution Networks Using Smart Controllers", CIRED 2013, Stockholm

[14] P. Parikh et. al., "Distributed Fault Detection, Isolation, and Restoration (FDIR) Technique for Smart Distribution System", 66th Annual Conference for Protective Relay Engineers, 2013

[15] S. Mohagheghi et. al., "Applications of IEC 61850 in Distribution Automation", IEEE/PES PSCE 2011

## ANNEX

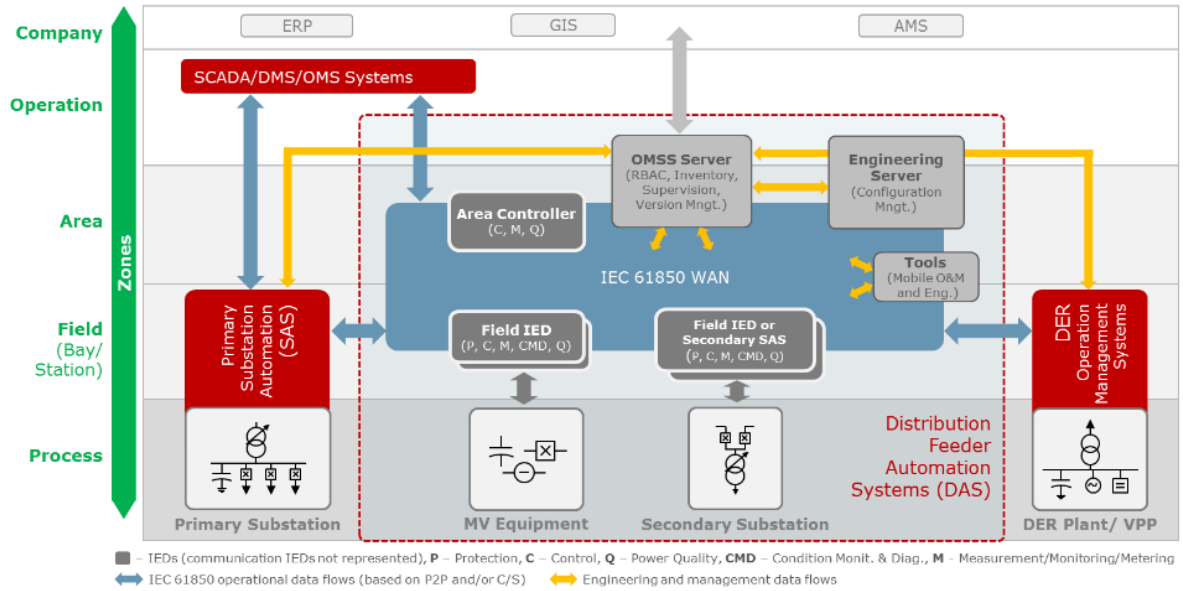


**Fig. 1 - Summarized DAS overview (mapped to the SGAM model [3], adapted).**

**Tab. 2 – Functional characterization of DAS maturity levels**

| Function | M0 | M1 | M2 |
|---|---|---|---|
| **RCM** | Conventional SCADA data including operational data/controls, and control of function operating modes/setpoints | | |
| | | | Use of synchronized measurements |
| **PQ** | Through event/data reporting (SOE, PQDIF, COMTRADE) | | |
| **CMD** | Basic data (equipment operations, measured electric quantities, operation times) | | |
| | | Distributed support for CBM including: (i) additional sensor data and critical alarms (temperature, humidity, loading), (ii) asset condition/health/ageing estimates and maintenance alarms. Identification, location and tracking of primary assets | |
| | | | Sophisticated and asset specific sensors. Accurate estimates of asset ageing and performance. Overloadability capacity assessment for dynamic rating. Maintenance prognoses/recommendations. Fault-prevention schemes. |
| **FP** | Substation and recloser-based coordinated feeder protection (I/U/Freq. functions). Relay operation/fault reporting (COMTRADE, fault reports) | | |
| | | Communication-based breaker and feeder protection schemes with use of feeder breakers/reclosers. Directionality as standard option for substation and feeder relays. Integration of DER/DG units. | |
| | | | Use of distance and differential protection functions. DER/DG integration using communication-based schemes. |
| **AS** | | Activation of calculated setting groups | Dynamic settings. |
| **FL,FD** | Use of substation relays and feeder fault level detectors (FD). | | |
| | | Use of directional elements and impedance calculations at FIEDs | |
| | | | Use of differential measurements and accurate FIED-level calculations. |
| **Isolation (FDIR)** | Use of local time, measurements and re-energising cycles | Faster isolation no re-energising cycles | Very fast isolation function distributed in communicating FIEDs |
| **Restoration (FDIR)** | Through pre-calculated scenarios | Use of topology methods, breaker/source capacity and load calculations (radial or mesh). | Very fast FDIR restoration function. Use of topology, state estimation and power flow (network models) for optimized reconfiguration (load balance, voltage, etc.). Control of DER for additional recovery scenarios. Support for islanded feeder operating mode and synchronized reconnection of sources. |
| **VVC** | | Substation OLTC control (and feeder capacitor banks) based on feeder measurements (VVC logic hosted in AC). Introduction of regulating feeder MV/LV transformers. | |
| | | | Use of controllable DER/DG/DR as additional control scenario |
| **FR,DC** | | Employed in critical feeders for specific scenarios | Employed through use of distributed applications based on network models. |

**Tab. 3 – Key architectures for DAS maturity levels**

| | M0 | M1 | M2 |
|---|---|---|---|
| **Typical DAS Architecture (IEC 61850)** | Hierarchical Telecontrol | Hierarchical Distribution Areas | Distributed Area Automation |
| **Typical Secondary Substation Architecture** | RTU | Proprietary | Distributed IEC 61850 Substation Automation System |
| **Use of Communication Services for Operation** | C/S (F-CC) | C/S (F-CC, F-A, A-C) | |
| | | GOOSE P2P (F-F) | GOOSE P2P (F-F) |
| | | | SV (F-F) |
| *Typical allocation of functions for DAS* | | | |
| **RCM** | FIED | FIED, AC | |
| **CMD, FP, FL, FD** | FIED | | FIED, AC |
| **AS** | FIED | AC | FIED, AC |
| **PQ** | FIED | | |
| **FDIR** | FIED | AC | FIED |
| **VVC** | | AC | FIED, AC |
| **FR, DC** | | | AC |