

# interscada

## System Operator Needs & Requirements for Future SCADA Systems / D1.1

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WP1, T1.1

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# Executive Summary

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The transition to a decarbonized, decentralized, and digitalized energy system is reshaping the operational landscape for Transmission and Distribution System Operators (TSOs and DSOs). The proliferation of Distributed Energy Resources (DERs), the emergence of hybrid AC/DC networks, and the increasing complexity of grid operations demand a new generation of Supervisory Control and Data Acquisition (SCADA) systems. This deliverable D1.1 of the InterSCADA project addresses these challenges by identifying the current limitations, future needs, and strategic directions for SCADA evolution.

This report provides a comprehensive analysis of existing SCADA, Energy Management Systems (EMS), and Advanced Distribution Management Systems (ADMS), focusing on their capabilities, limitations, and integration with emerging technologies. It outlines the necessity of architectural evolution from monolithic to modular and open-source SCADA platforms, emphasizing the need for interoperability, scalability, and cybersecurity. Furthermore, a thorough examination of the technical aspects pertinent to hybrid AC/DC systems is presented, differentiating between High Voltage Direct Current (HVDC) and Medium Voltage Direct Current (MVDC) applications, their respective control mechanisms, and the prevailing state of regulatory and standardization frameworks.

A key contribution of this deliverable is the extensive engagement with worldwide TSOs and DSOs achieved through a series of bilateral interviews and a survey. The aggregated findings from this investigation have been synthesized into a SWOT analysis, revealing strengths such as robust data handling and established functionalities, alongside weaknesses like vendor lock-in, fragmented architectures, and limited DER visibility. Opportunities include AI integration, open-source development, and enhanced interoperability, while threats encompass cybersecurity risks and regulatory complexity.

The report identifies critical gaps in current SCADA systems, particularly in supporting hybrid AC/DC operations, real-time data synchronization, and modular scalability. It highlights the need for advanced algorithms, improved training tools, and standardized frameworks to manage the behavior of modern grids.

In summation, this deliverable identifies critical shortages in contemporary SCADA functionalities, particularly concerning hybrid AC/DC integration, real-time data exchange and comprehensive DER monitoring. This substantiates the InterSCADA project's methodological approach towards the development of a modular and open-source platform. Additionally, the findings presented herein are expected to inform and guide InterSCADA's contributions to relevant regulatory and standardization efforts within the continually evolving energy sector.



# Table of contents

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Executive Summary.....	5
Table of contents .....	6
List of Tables .....	8
List of Figures .....	9
1. Introduction.....	14
1.1. The Evolution of SCADA-Enabled Control Centres: Meeting New Operational Challenges .....	14
1.2. Structure of the Document.....	17
2. Supervisory Control and Data Acquisition.....	18
2.1. Functionality Diagram.....	19
2.2. Operator Room Station.....	23
2.3. Communication Infrastructure .....	24
2.4. Master and Remote Terminal Units.....	28
2.5. SCADA Cybersecurity .....	29
2.6. Energy Management System and Distribution Management System.....	32
2.6.1. Energy Management Systems.....	33
2.6.2. Distribution Management System (DMS) and Advanced Distribution Management System (ADMS) .....	37
2.6.3. Advanced Metering Infrastructure.....	50
2.6.4. Distributed Energy Resource Management System.....	52
3. Open Architectures.....	55
3.1. Barriers to Openness in Control System Architectures.....	55
3.2. Potential Solutions.....	55
3.2.1. Control Algorithm Visibility and Development Capability .....	56
3.2.2. Transferability and Access Rights of Control Algorithms.....	57
3.3. Open Environment.....	58
4. Hybrid AC/DC Systems .....	62



4.1.	DC Technology.....	62
4.2.	DC in Hybrid AC/DC Systems .....	63
4.2.1.	HVDC .....	63
4.2.2.	MVDC .....	68
4.2.3.	Configuration of MVDC and HVDC Networks .....	70
4.3.	Operation of Hybrid AC/DC Networks .....	72
4.3.1.	Control of HVDC systems .....	72
4.3.2.	Control of MVDC Systems .....	74
4.3.3.	Protection for DC Systems .....	76
4.4.	Regulatory and Standardization Overview .....	77
4.4.1.	HVDC Regulations and Standards .....	77
4.4.2.	MVDC Regulations and Standards.....	80
4.5.	SCADA for AC/DC Networks .....	82
5.	Grid Operators Viewpoint .....	84
5.1.	Interviews .....	85
5.2.	SWOT Analysis .....	86
5.2.1.	Strengths.....	88
5.2.2.	Weaknesses .....	89
5.2.3.	Opportunities.....	91
5.2.4.	Threats.....	92
5.3.	Gaps.....	94
5.4.	Survey .....	98
5.4.1.	Analysis of Survey Results .....	107
6.	Conclusions .....	109
	Appendix A - Interview questions .....	110
	Appendix B - Survey questions .....	112
	Bibliography .....	115



# List of Tables

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Table 1. Acronyms used in this document .....11

Table 2. Common Types of Cyberattacks Targeting SCADA Systems and Their Characteristics (adapted from [5]) .....30

Table 3. Example of Data Exchange Between DMS and OMS Systems .....52

Table 4. SWOT Analysis for the grid operators' viewpoints. ....87

Table 5. Identified gaps .....94





## List of Figures

---

Figure 1. Evolution of the TSO operator's decision-making environment over the decades [1] .....	15
Figure 2. Technologies That Have Transformed Distribution Grid Operation [2] .....	16
Figure 3 Evolution of SCADA systems [3] .....	18
Figure 4. Representative Data Acquisition and Communication in SCADA Systems .....	20
Figure 5. Illustrative Example of a Monolithic SCADA Architecture .....	21
Figure 6. Illustrative Example of a Distributed SCADA Architecture .....	22
Figure 7. Illustrative Example of a Networked SCADA Architecture .....	23
Figure 8 Layers of Transmission System SCADA: The four functional layers of power system SCADA (left) a SCADA architecture in HV transmission networks (right) [13].....	25
Figure 9. Fibre Optic Topology in SCADA Communication Networks [].....	27
Figure 10. SCADA communication infrastructure: PLCC topology [12] .....	27
Figure 11. SCADA communication infrastructure: WiMAX topology [12] .....	28
Figure 12 Example EMS architecture for a TSO, showing core and advanced functionalities integrated with SCADA interfaces. ....	33
Figure 13. Illustrative DMS Architecture Showing System-Level Interoperability.....	38
Figure 14. DMS Application Architecture .....	39
Figure 15. DMS Application Architecture - Broken Down by Areas .....	40
Figure 16. Reference Model for GIS and ADMS System Integration .....	42
Figure 17. Example Architecture of an Outage Management System .....	44
Figure 18. Illustrative Architecture of AMI and MDMS Integration .....	51
Figure 19. Example Architecture of a Distributed Energy Resource Management System .....	54
Figure 20. Example reference architecture for DMS systems.....	56
Figure 21. Overview of an Open Architecture for SCADA/EMS/DMS Platforms.....	59
Figure 22. Example of CSC [1] .....	66
Figure 23. Example of VSC [24]. ....	67



Figure 24. Conceptual representation of hybrid AC/DC distribution networks [25].	68
Figure 25. MVDC network configurations: (a) point-to-point, (b) radial, (c) meshed and (d) ring (only for MVDC) [25].	71
Figure 26. General continuous control architecture for HVDC systems [27].	73
Figure 27. Methodology for the analysis and process of grid operators' viewpoints.	85
Figure 28. Survey Results – Responses to Question 1	99
Figure 29. Survey Results – Responses to Question 2	100
Figure 30. Survey Results – Responses to Question 3	101
Figure 31. Survey Results – Responses to Question 4	101
Figure 32. Survey Results – Responses to Question 5	102
Figure 33. Survey Results – Responses to Question 6	103
Figure 34. Survey Results – Responses to Question 7	103
Figure 35. Survey Results – Responses to Question 8	104
Figure 36. Survey Results – Responses to Question 9	105
Figure 37. Survey Results – Responses to Question 10	105
Figure 38. Survey Results – Responses to Question 11	106
Figure 39. Survey Results – Responses to Question 12	107



## List of Acronyms

Table 1. Acronyms used in this document

AC	Alternate Current
ADMS	Advanced Distribution Management System
AGC	Automatic Generation Control
AOR	Area of Responsibility
API	Application Programming Interface
BESS	Battery Energy Storage Systems
COTS	Commercial Off-The-Shelf
CA	Contingency Analysis
CSC	Current Source Converters
DC	Direct Current
DC-FRT	DC- Fault Ride Through
DG	Distributed Generation
DER	Distributed Energy Resources
DMS	Distribution Management System
DOPF	Distribution Optimal Power Flow
DSO	Distribution System Operator
ELS	Emergency Load Shedding
EMI	Electromagnetic Interference
EMS	Energy Management System
FLISR	Fault, Location, Isolation, and Service Restoration
FSDs	Fault Separation Devices
FSZs	Fault Separation Zones
GIS	Geographic Information Systems
GPS	Global Positioning System
GUI	Graphical User Interface



HIS	Historical Information System
HMI	Human Machine Interface
HV	High Voltage
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IGBT	Insulated Gate Bipolar Transistor
IP	Internet Protocol
IT	Information Technology
LAN	Local Area Network
LTE	Long-Term Evolution
LVDC	Low Voltage DC
MTM	Multiple to Multiple
MTU	Master Terminal Unit
MV	Medium Voltage
MVDC	Medium Voltage DC
NDA	Non-Disclosure Agreement
OLE PC	Object Linking and Embedding for Process Control
OLPF	On-Line Power Flow
OMS	Outage Management System
ONR	Optimal Network Reconfiguration
OPF	Optimal Power Flow
OTS	Operator Training Simulator
PAS	Power Application Software
PLC	Programmable Logic Controller
PLCC	Power Line Carrier Communication
PTM	Point to Multiple
PTP	Point to Point



PV	Photovoltaic
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SOM	Switch Order Management
SONET	Synchronous Optical Networking
STLF	Short Term Load Forecast
SVCs	Static VAR Compensators
TCP	Transmission Control Protocol
TSO	Transmission System Operator
VSC	Voltage Source Converter
VVC	Voltage/Var Control
VVO	Volt-VAR Optimization
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access



# 1. Introduction

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The large-scale introduction of renewable-based technologies in the energy sector—such as photovoltaic (PV) systems, wind turbines, and Battery Energy Storage Systems (BESS)—is profoundly transforming the management of electrical grids. While the proliferation of Distributed Energy Resources (DERs) is significantly contributing to the replacement of fossil-fuel-based energy generation, it has also introduced several challenges in the monitoring and control of networks, placing additional pressure on the daily operations of System Operators (SOs).

An additional factor contributing to this grid transformation is the deployment of Direct Current (DC) technology. While DC systems are already widely implemented at the High Voltage (HV) level—e.g., through High Voltage Direct Current (HVDC) systems—their adoption at the Medium Voltage (MV) level is still in its early stages. Alongside the electrification of the heating and mobility sectors, DC technology is facilitating the efficient integration of electrical assets. This is leading to the emergence of DC sub-networks, which, when combined with existing Alternating Current (AC) infrastructure, result in hybrid AC/DC networks for both transmission and distribution systems. Like the spread of DERs, these hybrid networks introduce new challenges for grid management, necessitating the development of advanced solutions and tools.

This deliverable focuses on the challenges faced by System Operators—both Transmission System Operators (TSOs) and Distribution System Operators (DSOs)—in the current landscape and in anticipation of increased DER penetration and the rise of hybrid AC/DC networks. It lays the foundation for several activities within the InterSCADA project, emphasizing the priorities for developing monitoring and control algorithms for AC/DC networks, as well as outlining the features of the InterSCADA platform. Furthermore, this document will provide substantial input for the analysis of regulatory and standardization frameworks.

## 1.1. The Evolution of SCADA-Enabled Control Centers: Meeting New Operational Challenges

As SCADA systems have evolved—driven by advances in information technology, communications, and system integration—the role and configuration of control centers for transmission grid operations have undergone a significant transformation (Figure 1). Traditionally, these control rooms depended heavily on manual operator intervention for real-time activities such as generation dispatch, demand forecasting, power flow



management, and the coordination of planned and unplanned outages. These processes were often repetitive, time-consuming, and cognitively demanding, offering limited benefits in terms of enhancing situational awareness.

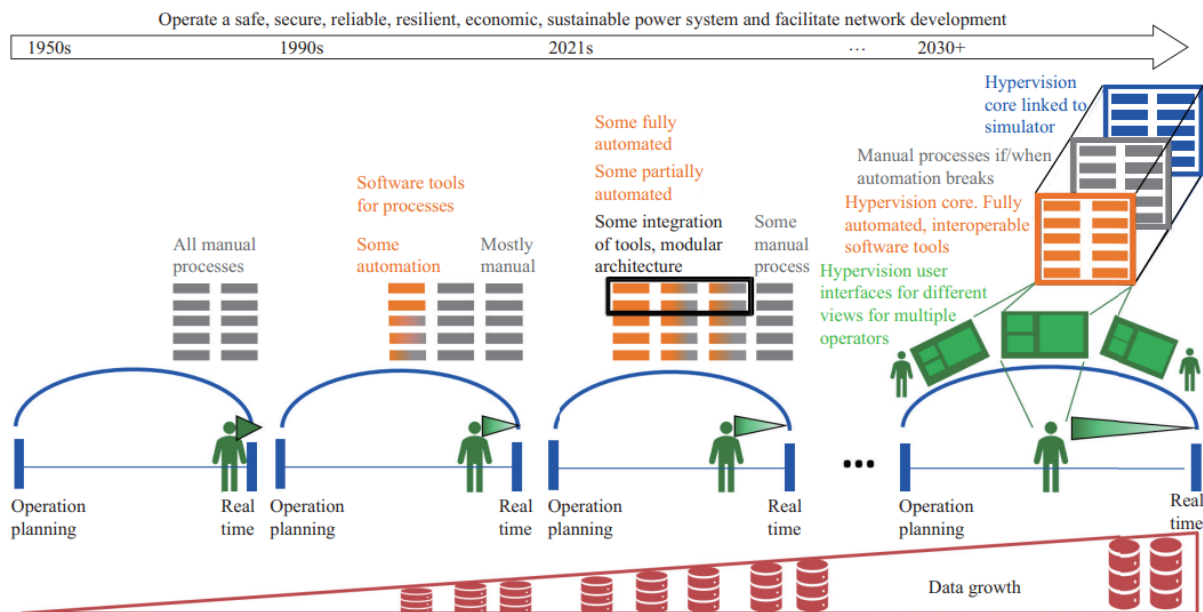


Figure 1. Evolution of the TSO operator's decision-making environment over the decades [1]

In response to growing system complexity, transmission control centers have increasingly adopted automation to support core functions. Automatic Generation Control (AGC), enhanced market systems, automated forecasting tools, voltage regulation, and protection schemes are now widely deployed, reducing the need for operator involvement in routine tasks. This shift enables operators to focus on rare or critical events where human expertise is essential. However, several administrative and coordination processes—such as incident logging, reporting, asset condition monitoring, and workforce management—are still primarily handled manually. These tasks often absorb valuable operator time without directly contributing to real-time decision-making or system visibility.

Looking ahead, further advancements in SCADA platforms are expected to extend automation into these areas. Integrating applications under a unified interface and providing operators with better support across extended time horizons will be critical. The overarching objective is to reduce the cognitive burden associated with routine actions, while enhancing decision quality and readiness in an increasingly complex grid environment.

This need is further reinforced by the growing deployment of hybrid AC/DC architecture and HVDC links, which introduce new operational dynamics and monitoring requirements. These systems often feature fast-acting controls, multi-terminal configurations, and complex



protection schemes that cannot be managed using traditional SCADA functionalities alone. Future transmission control centers will need to incorporate enhanced situational awareness tools, real-time analytics, and interoperable platforms capable of supporting hybrid system coordination—ensuring stability, reliability, and optimal system performance across both AC and DC domains.

Similarly to TSOs, DSOs have evolved significantly over past decades to meet increasing demands for productivity, reliability, and safety. Today's DSOs are equipped with advanced tools to convert large volumes of data into actionable insights, but this capability is the result of a long technological evolution.

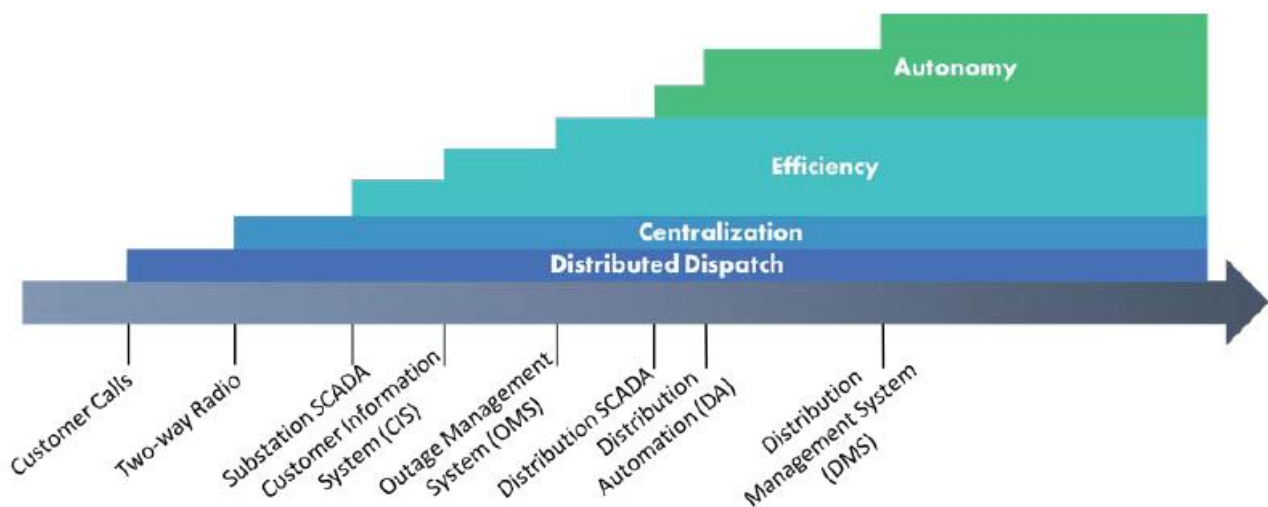


Figure 2. Technologies That Have Transformed Distribution Grid Operation [2]

Initially, control center operators—often called “dispatchers”—primarily served as communication hubs, handling customer calls and relaying instructions to line crews who independently managed system operation and switching. Their role was largely administrative, with limited real-time control. Technological advances transformed this role. Two-way radios enabled centralized coordination, and SCADA deployment at substations gave DSOs direct control over critical equipment, shifting operational authority from field crews. Customer Information Systems (CIS) and Outage Management Systems (OMS) further streamlined processes, improving outage response times.

The introduction of Distribution Automation (DA) devices increased system complexity, requiring DSOs to manage automated assets and clearance authority while handling growing volumes of data and alarms, particularly during high-stress events. To manage these challenges, many utilities have adopted Distribution Management Systems (DMS) with advanced capabilities such as Volt/VAR Optimization (VVO), Distribution System State





Estimation (DSSE), and Fault Location Isolation and Service Restoration (FLISR). These applications transform diverse data streams into automated, actionable operations.

SCADA and DMS platforms must continue to evolve to integrate distributed energy resources (DERs) and manage emerging technologies like hybrid AC/DC grids and HVDC links. These advancements require enhanced situational awareness, interoperability, and control functionalities to ensure efficient and reliable grid operation.

SCADA/EMS/ADMS providers closely guard their proprietary control algorithms, creating challenges for utilities to independently understand, customize, and transition these critical systems as grid complexity and diversity increase, leading to vendor lock-in that limits utility autonomy. One of the primary goals of the InterSCADA project is to develop open, interoperable SCADA solutions that empower utilities with greater transparency, flexibility, and independence in managing complex and evolving power systems.

## 1.2. Structure of the Document

The content of this deliverable is organized as follows: Chapter 2 traces the historical evolution of SCADA, EMS, and DMS systems alongside the growing complexity of power systems. In turn, Chapter 3 introduces the current landscape and challenges of creating open SCADA architectures—highlighting the need for frameworks that enable utilities to preserve and transfer their control logic across platforms through open, interoperable solutions. Subsequently, Chapter 4 describes the outline of DC, for HVDC and MVDC applications; together with the analysis of the existing technologies, the overview of control solutions as well as the standardization situation is included. Chapter 5 presents the grid operators' viewpoints on SCADA systems; the outcomes of their interviews allowed the identification of existing gaps; moreover, the same section includes the results of the conducted survey for DSOs and TSOs. The chapter 6 concludes the document.



## 2. Supervisory Control and Data Acquisition

Supervisory Control and Data Acquisition (SCADA) systems are crucial for monitoring, collecting, and processing data across various industries, including electric power systems. The concept of SCADA emerged in the 1970s to describe systems that oversee and control automated processes.

Over the years, SCADA systems have significantly evolved, especially with the advent of local area networks (LANs) and modern information technology (IT) standards. These advancements have enhanced SCADA's functionality and its ability to interconnect with other systems (Figure 3). A modern SCADA for electrical power systems comprises several key components. Measurement and control devices play a vital role in monitoring system parameters such as voltage and current and executing control functions like opening breakers or reclosers. These devices are interfaced with units that provide access to the communication network, which facilitates data transfer between the devices and the SCADA host. The SCADA host processes data from various devices and sends command signals to them, ensuring efficient system operation.

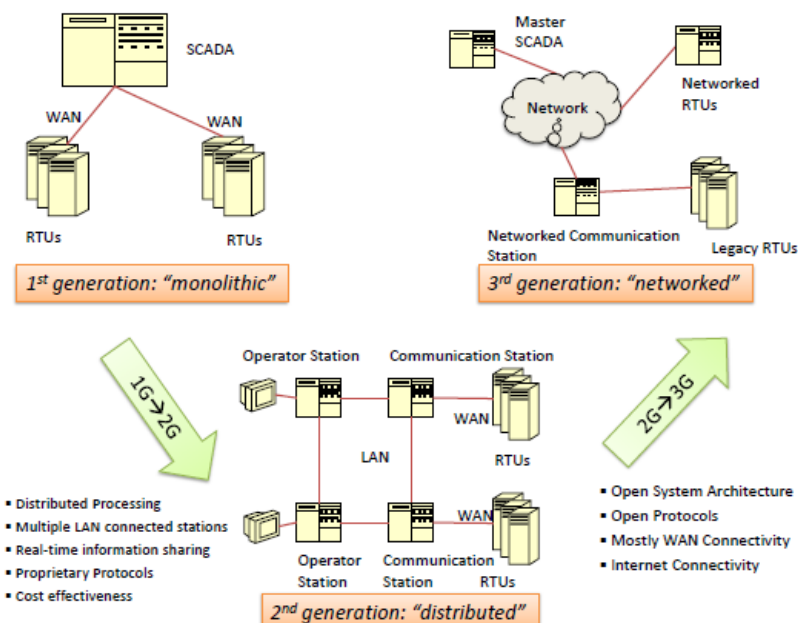


Figure 3 Evolution of SCADA systems [3]



The integration of Human Machine Interface (HMI) has greatly improved the usability of SCADA systems, contributing to their widespread deployment [4]. In electric power systems, SCADA allows for near real-time monitoring and control of substation and field devices. Data is typically updated every second's scale (with variance in granularity depending on the systems in use) and can be archived for trend analysis and event investigation, providing valuable insights into past power system events.

In earlier SCADA systems, devices were individually and directly connected to remote terminal units (RTUs), which interfaced with the broader communication system [5]. However, modern SCADA systems have transitioned to using Intelligent Electronic Devices (IEDs) instead of RTUs. IEDs enable direct network connections, eliminating the need for dedicated RTUs in newer substations. The SCADA host, connected to the communication network, processes data from RTUs and IEDs, making information available to system operators and processing command signals from them.

Most commercially available SCADA systems can categorize and prioritize gathered data, providing display and alarm functions. They also support accurate time synchronization and event time-tagging. Advanced event logging, data analysis, and filtering capabilities help utility operators locate precise information, enabling effective data collection and decision-making.

## 2.1. Functionality Diagram

In power systems, data is collected from various field devices, some of which also serve as control devices. For instance, a shunt capacitor can provide voltage magnitude values and can be opened or closed remotely via the Distribution Management System (DMS). Depending on the size and complexity of a substation and its associated distribution feeders, there can be numerous measurement points and controllable devices. Similarly, in transmission systems, SCADA systems—usually integrated with the EMS—collect data and issue control signals to key assets such as circuit breakers, power transformers (e.g., tap changer control), and Flexible AC Transmission Systems (FACTS) devices like Static VAR Compensators (SVCs). These devices help manage voltage levels, reactive power flow, and system stability over wider areas.

In modern substations, each measurement and control device are typically an IED connected to the substation's local area network (LAN). This LAN then connects to the enterprise communications network, linking the IEDs to the SCADA host. In some cases, there may also be a SCADA host located at the substation itself, depending on the specific system architecture.



SCADA systems generally consist of several subsystems. Measurement and control devices are individual units that measure data and control physical actions, such as voltage potential transformers, current transformers, breakers, and capacitors. The communications interface connects these devices to the communications network. While older RTUs would connect multiple devices to the network, newer IEDs have integrated communications interfaces, such as programmable logic controllers (PLCs) with built-in networking capabilities.

The communications network, which may consist of one or more networks depending on the system architecture, is responsible for transmitting data and control signals between different locations. A data historian is a centralized database that logs all system information. It gathers and archives grid information collected by sensors on the network. IEDs provide operators with a significant amount of data, which the historian's data logging and reporting functionality can analyze to generate valuable information. This enables operators to consider both current operational scenarios and past events. For example, a historian can provide details on transformer loading or a list of triggered alarms

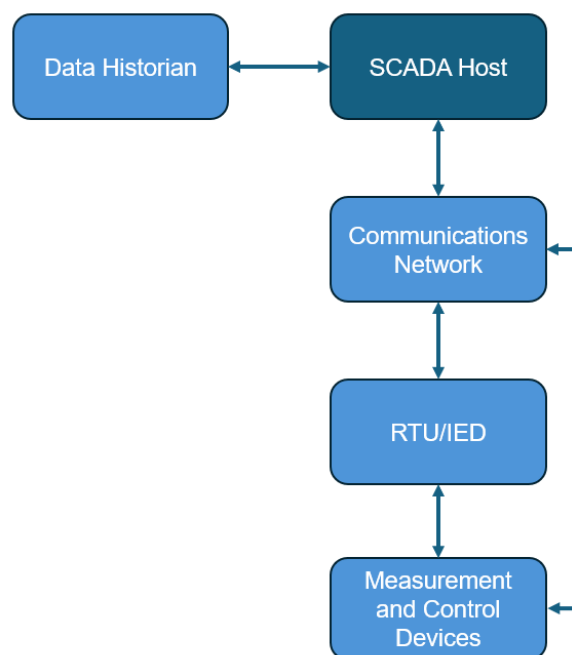


Figure 4. Representative Data Acquisition and Communication in SCADA Systems

The discussion above outlines a generic SCADA system (Figure 4), noting that specific deployments are tailored to utility requirements and can evolve over time. SCADA systems



in the electric power industry are generally categorized [5] as monolithic, distributed, or networked. The first generation of SCADA systems, known as monolithic systems (Figure 5), were deployed by electric utilities during the era of mainframe computing. These highly centralized systems were typically isolated from other systems and used proprietary wide-area network (WAN) protocols designed by equipment vendors. These protocols only allowed for the measurement and control of remote devices. In a monolithic SCADA system, each RTU communicates directly with the SCADA host, also known as the "SCADA Master." It is possible for a single substation to have multiple RTUs in this architecture.

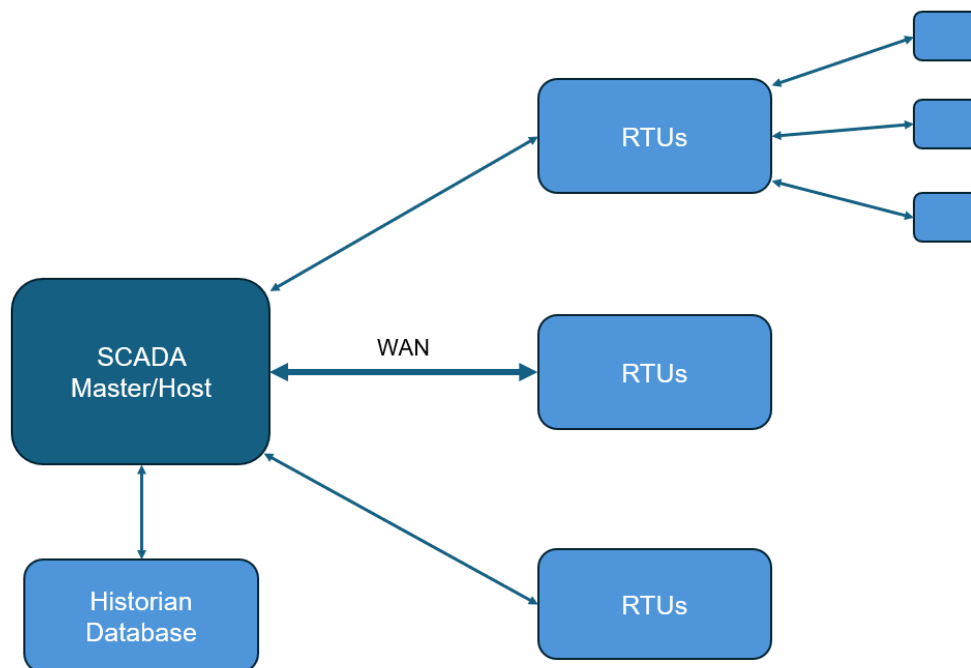


Figure 5. Illustrative Example of a Monolithic SCADA Architecture

The second generation of SCADA systems, known as distributed SCADA (Figure 6), featured a three-level control-center hierarchy. While the substation architecture remained similar to the first generation, with multiple devices communicating through one or more RTUs, the communication process changed. Instead of RTUs communicating directly with the SCADA host, they interfaced with a communication or front-end server located in the control center [5]. This server was part of a LAN accessible by internal utility systems, including the SCADA host.



In a distributed SCADA system, the LAN allowed multiple systems to access the SCADA infrastructure. However, the LAN protocols were typically proprietary, limiting the ability to interconnect the SCADA system with other utility systems. Additionally, the external WANs were usually restricted to RTU protocols.

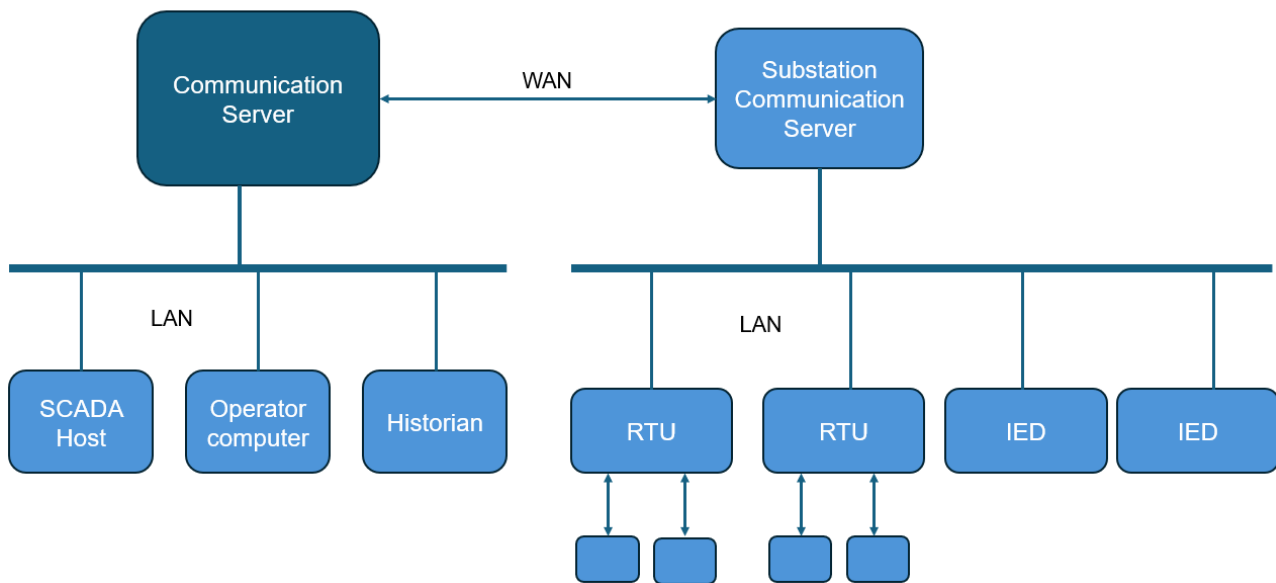


Figure 6. Illustrative Example of a Distributed SCADA Architecture

Modern SCADA systems resemble the second-generation distributed systems but feature enhanced networked communication at both the substation and control center levels. In substations, IEDs connect directly to the substation's wide-area network (WAN), which includes a communications server acting as the gateway for the entire substation. This server connects to the control center via the WAN. Newer deployments may also include sub-networks, known as process buses, for high-speed data exchange between devices, representing a higher level of system integration.

At the control center, the traditional SCADA Master's role has evolved, with communications now handled by the WAN, facilitated by the adoption of open standards and protocols like Internet Protocol (IP). A communications server at the control center connects to a LAN, allowing multiple systems to access SCADA. While new substations typically follow this architecture, existing substations can integrate a mix of IEDs and legacy RTUs. This setup allows for greater integration, with systems like the Outage Management System (OMS) also connected to the LAN, and potentially numerous other systems as well.



Figure 7 represents a networked SCADA system incorporating newer IEDs, some of which utilize a process bus [5]. The figure also depicts enhanced integration at the control center, where the Outage Management System (OMS) is connected to the local area network (LAN). Nowadays, SCADA systems are accessible via web browsers and mobile devices, allowing users to monitor and control operations remotely with greater convenience [6].

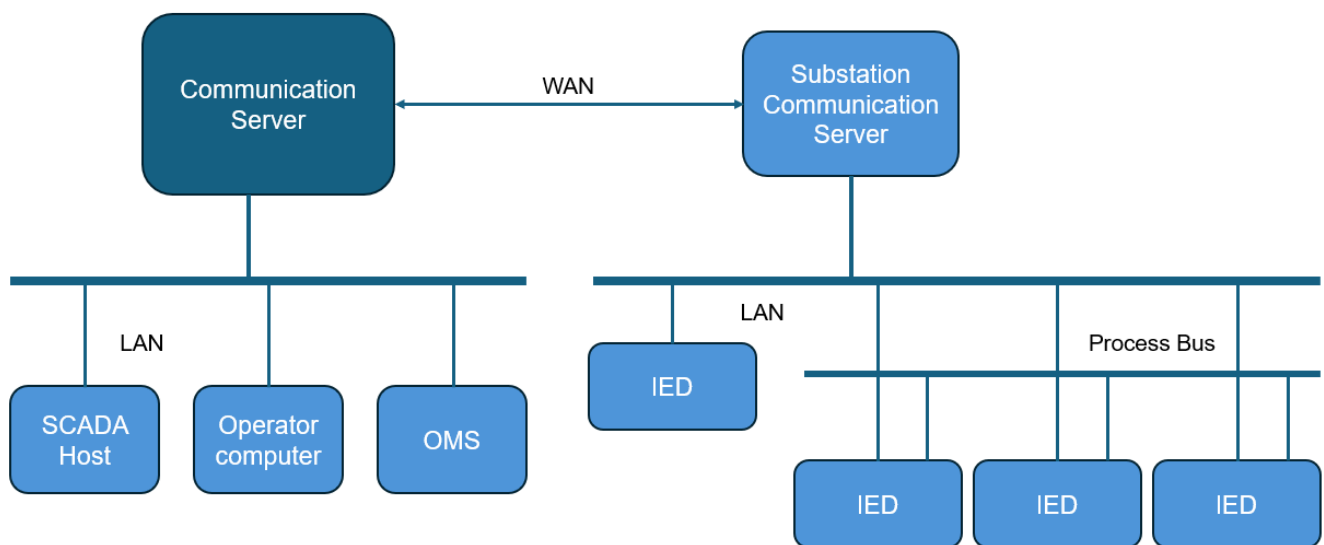


Figure 7. Illustrative Example of a Networked SCADA Architecture

## 2.2. Operator Room Station

The operations room of a SCADA system is a critical component, featuring a user interface unit known as the Human Machine Interface (HMI). The HMI visually represents the hardware, software, and communication components of the system. Its specifications vary based on network structure needs, with some designed to be rigid and others, like Commercial Off-The-Shelf (COTS) SCADA systems, being more flexible and compatible with various hardware and software.

The HMI offers several key services to operators:



1. It visually presents the SCADA components using familiar symbols, such as green lights for "OK" states and red lights for "Alarm" states.
2. It provides operational functions to control MTUs, RTUs, and PLCs.
3. It displays values from analog and digital I/O devices, often using gauges or bars to show minimum and maximum allowed values, such as the voltage level of a substation.
4. It includes an alarm system that detects and responds to various alarm scenarios. These can be automated actions, like pre-programmed safety procedures, or notifications to operators via emails or text messages.

## 2.3. Communication Infrastructure

The communication infrastructure of SCADA systems presents challenges due to its reliance on coverage area, materials, and protocols. Various technologies have been employed in the SCADA field, including radio waves, serial modems, LANs, WANs, and Transmission Control Protocol/Internet Protocol (TCP/IP) over Synchronous Optical Networking (SONET) [7], [8]. The communication monitoring network can have different topologies, such as Point to Point (PTP), Point to Multiple (PTM), and Multiple to Multiple (MTM) [9], [10]. For large-scale SCADA systems, fiber optic, satellite, and microwave technologies are commonly used as communication mediums.

SCADA systems employ various communication protocols, some of which operate in on-demand mode, sending data only when requested. These protocols include RP-570, RS-485, Modbus, Profibus, and Conitel. Additionally, several standardized protocols are available, such as the International Electrotechnical Commission (IEC) 60870-5-101/104, IEC 61850, and Distributed Network Protocol (DNP3) [9]. Many of these protocols can function over TCP/IP, enhancing security. However, it is generally advised that SCADA systems should not be connected to the internet to avoid potential denial of services or cyber-attacks.

In 1996, Object Linking and Embedding for Process Control (OLE PC) was developed, enabling real-time data communication between different terminal manufacturers, RTUs, and MTUs [11]. Data in a SCADA system typically flows from field devices to a control center, with control signals sent from the control center to the field devices. Generally, signals and commands are only transmitted when there is a query from the SCADA master





station, and the actual data exchange is governed by the implemented communication protocols.

Older SCADA systems were developed before industry-wide standards for interoperability were established, leading to the creation of numerous proprietary protocols. These proprietary protocols were sometimes developed to encourage customer loyalty. Common SCADA protocols include Modbus RTU, RP-570, and Profibus, which are vendor-specific but widely adopted in many utilities. Standard protocols recognized by most SCADA vendors include IEC 60870-5-101/104, IEC 61850, and DNP3 (now also IEEE Standard 1815-2012). Many of these protocols now have extensions to operate over TCP/IP, simplifying system engineering and enabling seamless data exchange and communication. Typically, redundancy is provided to improve fault tolerance and communication system reliability.

SCADA communication networks have evolved through successive generations—Monolithic, Distributed, Networked, and Internet of Things (IoT)—driven by increasing system size and the number of connected devices [12]. For transmission systems, the SCADA network is typically structured into three hierarchical levels, as illustrated in Figure 8.

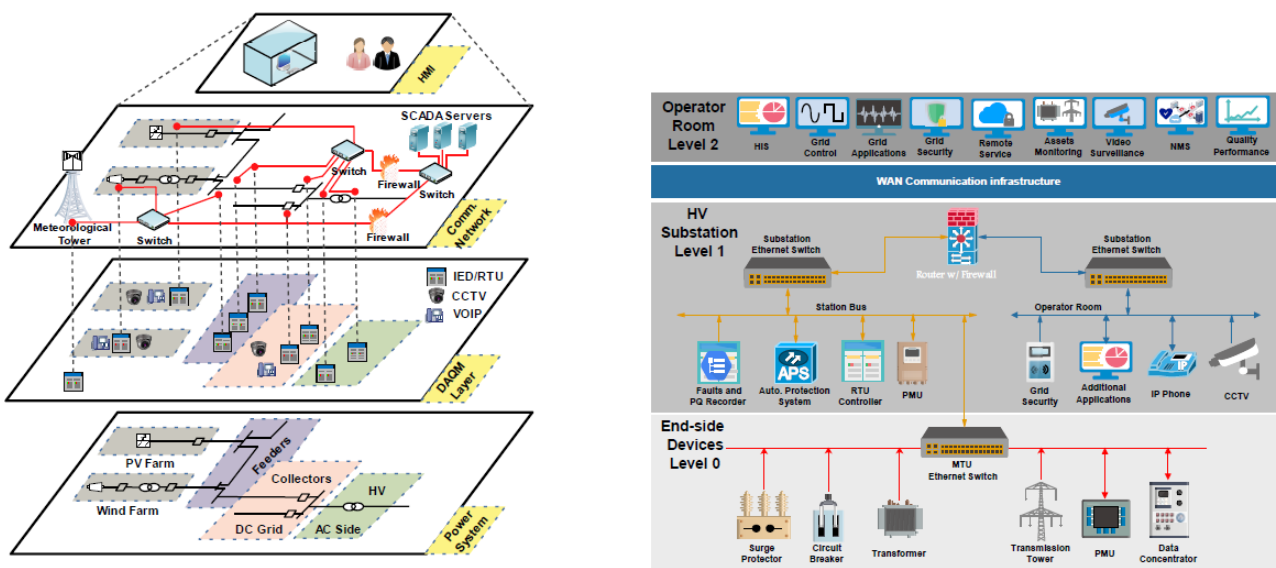


Figure 8 Layers of Transmission System SCADA: The four functional layers of power system SCADA (left) a SCADA architecture in HV transmission networks (right) [13]

A modern SCADA communication infrastructure is typically structured into four distinct layers, as illustrated in Figure 8 (left):



- **Power System Layer:** This foundational layer encompasses all physical electrical components in the power system, including generators, transformers, converters, feeders, and collector buses.
- **Data Acquisition and Monitoring Layer:** This layer comprises sensors and actuators—primarily Remote Terminal Units (RTUs)—responsible for collecting measurements at varying data rates and frequencies. It also includes circuit breaker controllers and power protection devices, forming the interface between the electrical assets and the communication infrastructure.
- **Communication Network Layer:** Serving as the backbone of the SCADA system, this layer interconnects various system levels and ensures reliable data flow. As shown in Figure 8 (right), it includes three key sub-networks:
  - **Controller Area Network (CAN):** A local communication network within each RTU, linking microcontrollers with their associated sensors and actuators.
  - **Power Area Network (PAN):** A narrow-area network that connects the Master Terminal Unit (MTU) with multiple RTUs. The communication protocol used depends on the specific controller architecture.
  - **Station Area Network (SAN):** A wide-area network providing communication between the PAN and the SCADA control center.
- **Human-Machine Interface (HMI) Layer:** This top layer includes software tools and graphical user interfaces (GUIs) designed to support operators. The HMI presents multiple menus, views, and control screens tailored to the different layers of the SCADA system, enabling effective system oversight and decision-making.

The distribution network has more electrical nodes to be monitored compared to the HV transmission network, making communication infrastructure a significant challenge for a robust SCADA system. Various communication topologies are available to address these challenges:

- **Fiber Optics:** Fibre optics are highly compatible with medium and low voltage distribution networks (Figure 9). Although the deployment cost is high due to civil works and expensive equipment, fiber optics offer robustness, noise-free transmission, wide data bandwidth, and an extendable communication medium.



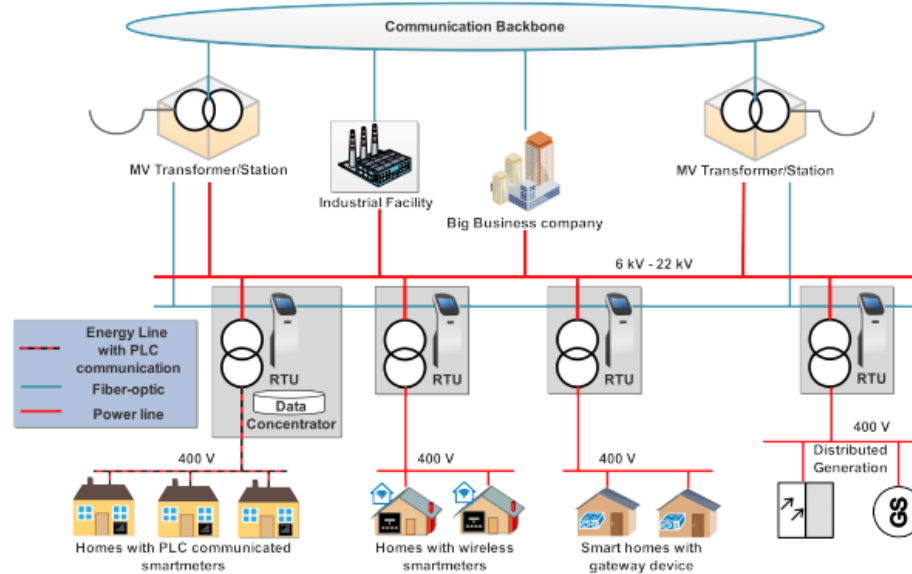


Figure 9. Fiber Optic Topology in SCADA Communication Networks [14]

- Power Line Carrier Communication (PLCC):** PLCC is advantageous because it is compatible with the traditional power grid, requiring no new assets or structures. It is often used as a fallback solution when other options are unavailable (Figure 10). However, the quality of communication depends on the type and age of the cables and the number of joints. Accurate planning of PLCC unit installation is essential to ensure low latency, reliable connections, and stable data metering.

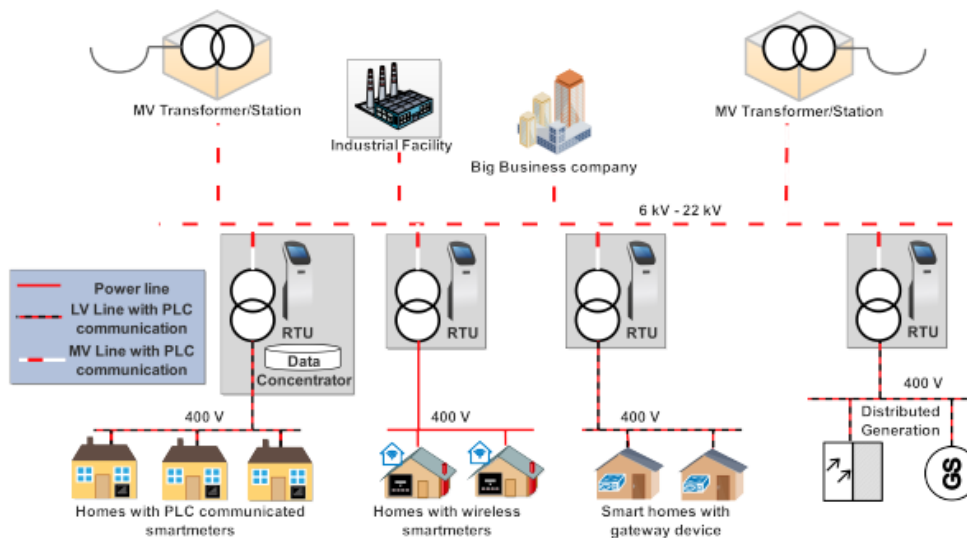


Figure 10. SCADA communication infrastructure: PLCC topology [14]

- **WiMAX and LTE:** WiMAX (Worldwide Interoperability for Microwave Access) and LTE (Long-Term Evolution) technologies are used in power system communication to connect lower networks with higher ones through backhauling mechanisms (Figure 11). Lower networks typically contain RTUs and data concentrators. This communication medium allows local networks to communicate privately with regional networks.

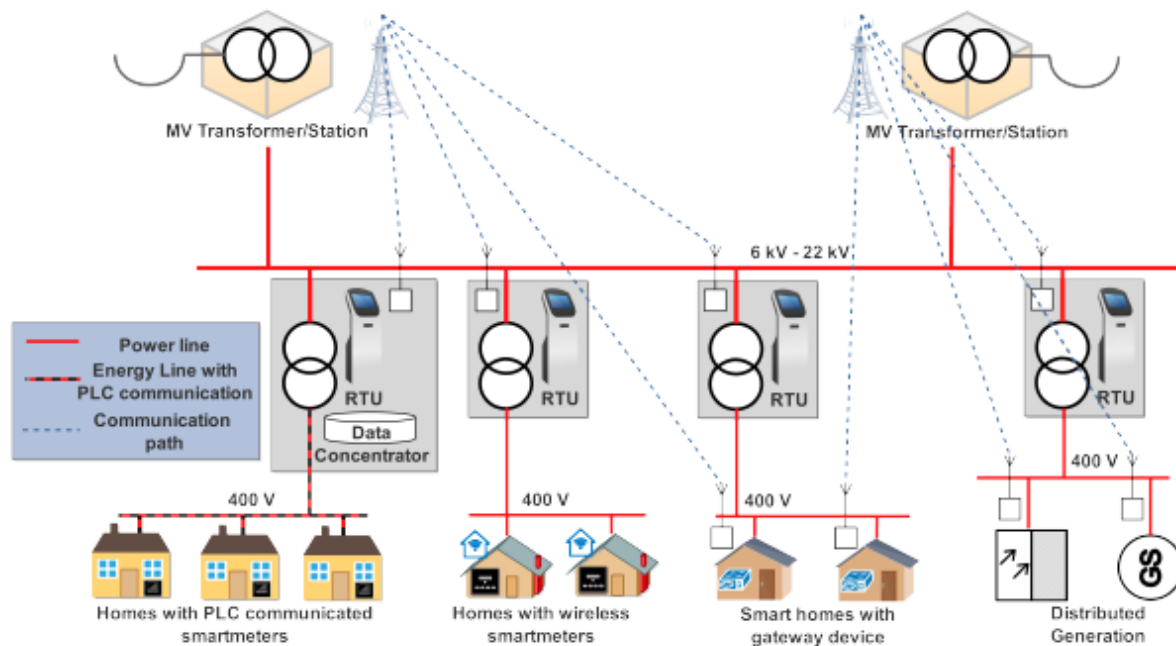


Figure 11. SCADA communication infrastructure: WiMAX topology [14]

## 2.4. Master and Remote Terminal Units

MTUs serve as the second control unit (Level 1) after the main station (Level 2) and are typically installed in substations, as represented in Figure 8. MTUs share similar characteristics with the main station, including HMIs and servers, and are connected to other MTUs via communication mediums like LAN or WAN. The HMI enables operators to control connected RTUs through predefined procedures and provides visual presentations of geographical and textual information, making it easy for MTU operators to understand.

RTUs act as the subordinates to the master station and MTUs. They are more advanced than PLCs and are considered an extended version of them. RTUs contain sensors, actuators, and a controller unit, operating in real-time and synchronized with the network. They can transmit data to the master terminal periodically or on-demand. Additionally, RTUs



have predefined emergency procedures to send high-priority signals and data to the master station in case of disasters or high-risk faults.

RTUs are geographically distributed and often equipped with Global Positioning System (GPS) modules to timestamp measurements. The communication medium for RTUs is typically a LAN or WAN link, utilizing various technologies such as radio, fiber optics, telephone wires, and microwaves. The standard for functional block programming, IEC 61131-3, is commonly used to develop PLC and RTU programs.

## 2.5. SCADA Cybersecurity

The evolution of SCADA systems has brought significant advancements but also increased their complexity and vulnerability. Modern SCADA architectures now include numerous new components such as computers, operator stations, communication servers, and various interconnected resources, all of which contribute to more complex data exchange and interactions within the system. As the number of components grows, so does the volume of data transmitted between them, creating additional challenges for maintaining system performance and reliability.

Furthermore, the integration of security measures like firewalls and antivirus software—while essential for protection—can introduce processing delays that impact timely data transfer and system responsiveness. Many organizations require SCADA systems to operate continuously with minimal data delay or loss, which places tight constraints on system timing and performance. In addition to increased complexity, SCADA communications are now more exposed to a wide range of cyber threats. The frequency and sophistication of cyberattacks targeting critical infrastructure—such as power plants, water treatment facilities, gas distribution, and nuclear control systems—have escalated in recent years. These attacks have evolved beyond basic methods like Denial of Service or Man-in-the-Middle attacks, posing significant risks to the availability, integrity, and security of SCADA networks [6].

SCADA networks face multiple cybersecurity threats, including [6], [15] :

- **Loss of availability:** Can cause power outages and disrupt power supply, potentially leading to cascading physical failures. Maintaining availability is a top security priority.
- **Loss of integrity:** Occurs when attackers alter data, such as through Man-in-the-Middle attacks, malware injection, or IP spoofing, leading to incorrect information being received.
- **Loss of confidentiality:** Happens when attackers eavesdrop on communications, exposing private data and violating privacy.



- **Repudiation:** When a sender denies having transmitted certain data, complicating accountability.
- **Specific attack tools:** Examples include Slowloris, GoldenEye, and Low Orbit Ion Cannon (LOIC).
- **Protocol vulnerabilities:** For example, Distributed Network Protocol 3.0 (DNP3) lacks strong authentication, enabling impersonation attacks.

The integration of internet connectivity, cloud computing, wireless communication, and social engineering has increased SCADA vulnerabilities, mainly due to weak encryption and insufficient real-time monitoring. Attacks can target all levels—from supervisory systems to field devices—and fall into three categories:

- **Hardware attacks:** Unauthorized physical access to tamper with devices, with access control being the main defense challenge.
- **Software attacks:** Exploits such as SQL injection, trojans, and buffer overflows targeting software weaknesses.
- **Network attacks:** Targeting communication layers (network, transport, application) and compromising confidentiality, integrity, availability, and non-repudiation.

Table 2 provides an overview of common cyberattack types that target SCADA systems, summarizing their main characteristics and typical impact on system security and operation.

Table 2. Common Types of Cyberattacks Targeting SCADA Systems and Their Characteristics  
(adapted from [6])

Type of SCADA Cyberattacks	Description
Eavesdrop	An attacker intercepts data during transmission between SCADA components (e.g., sensors, RTUs, control centers), compromising confidentiality without altering the data. Often used to collect sensitive information for later attacks.
Man-in-the Middle (MiM)	The attacker positions themselves between two legitimate devices, intercepting, modifying, or injecting messages. This compromises both integrity and



	confidentiality and can be used to alter control commands or falsify sensor data.
Masquerade	An attacker pretends to be an authorized user or device (e.g., a PLC or HMI) to gain unauthorized access. Often exploits authentication weaknesses in protocols like Modbus or DNP3.
Virus and Worms	Malicious software designed to infect SCADA systems. Viruses require human action to spread (e.g., via USB), while worms spread autonomously across networks, potentially causing denial of service or corrupting data.
Trojan Horse	Malware disguised as legitimate software. In SCADA, a trojan might appear as an update or utility but contains hidden malicious functions that open backdoors or leak data.
Denial of Service (DoS)	Overwhelms SCADA servers, HMIs, or communication links with excessive traffic, making systems unavailable. May halt operations or blind operators to real-time grid conditions.
Fragmentation	Sends deliberately fragmented or malformed packets to SCADA devices to exhaust resources or crash protocols that cannot properly reassemble them. Targets low-power or legacy field devices.
Cinderella	Bombards the authentication system (e.g., with repeated access attempts) to lock out legitimate users, exploiting limited login attempts or lockout thresholds in SCADA interfaces.





### Doorknob Rattling

Low-effort probing attack where an attacker repeatedly tries common passwords, ports, or default configurations to find weaknesses—similar to checking which doors are left unlocked.

## 2.6. Energy Management System and Distribution Management System

Power system operation and management rely on a suite of specialized platforms that support decision-making and operational control across different voltage levels of the electrical grid. Among these platforms, EMS and DMS play a central role in enabling safe, reliable, and efficient grid operations. Despite operating at different levels—EMS typically at the transmission level and DMS at the distribution level—both systems share the common goal of maintaining grid stability, optimizing operational performance, and ensuring continuity of service.

EMS and DMS share several key functionalities, including capabilities for monitoring the network in real time, detecting and responding to abnormal conditions, and supporting the operator through decision-making tools and analysis. Common functionalities include real-time data acquisition and visualization, network topology processing, alarm management and event logging, as well as support for operational planning and contingency analysis.

However, the specific capabilities and operational focus of EMS and DMS differ in response to the distinct characteristics of transmission and distribution networks. Transmission networks tend to be meshed and centrally controlled, while distribution networks are increasingly decentralized and shaped by the integration of DER, electric vehicles (EVs), and active consumers.

In the transmission domain, EMS is used by TSOs to manage large-scale power flows, support system balancing, and perform advanced functions such as state estimation, contingency analysis, and generation dispatch across wide geographic areas. EMS provides the centralized intelligence required to maintain the reliability and security of the high-voltage grid in real time.

In the distribution domain, DMS often acts as the central platform integrating other critical systems such as Geographic Information Systems (GIS) for spatial network modelling, Outage Management Systems (OMS) for restoration workflows, and Advanced Metering Infrastructure (AMI) for high-resolution, two-way metering. Furthermore, the emergence of





DER Management Systems (DERMS) has expanded the operational scope, enabling utilities to monitor, forecast, and coordinate DERs to provide grid services.

As distribution grids become more dynamic and complex, the boundary between DMS and these adjacent systems is increasingly blurred, requiring tighter integration and interoperability to deliver the required level of flexibility, observability, and control. Similarly, coordination between EMS and DMS is becoming more relevant, particularly in the context of high DER penetration and the growing need for TSO-DSO cooperation.

### 2.6.1. Energy Management Systems

An EMS is an integrated suite of computer-based tools, communication networks, and hardware that enables TSOs to monitor, control, and optimize the operation of electric power generation and transmission systems. EMS plays a crucial role in ensuring the reliable, secure, and efficient functioning of the transmission grid by providing advanced analytical capabilities and real-time operational support. Some foundational and advanced applications of the EMS are outlined below and illustrated in Figure 12.

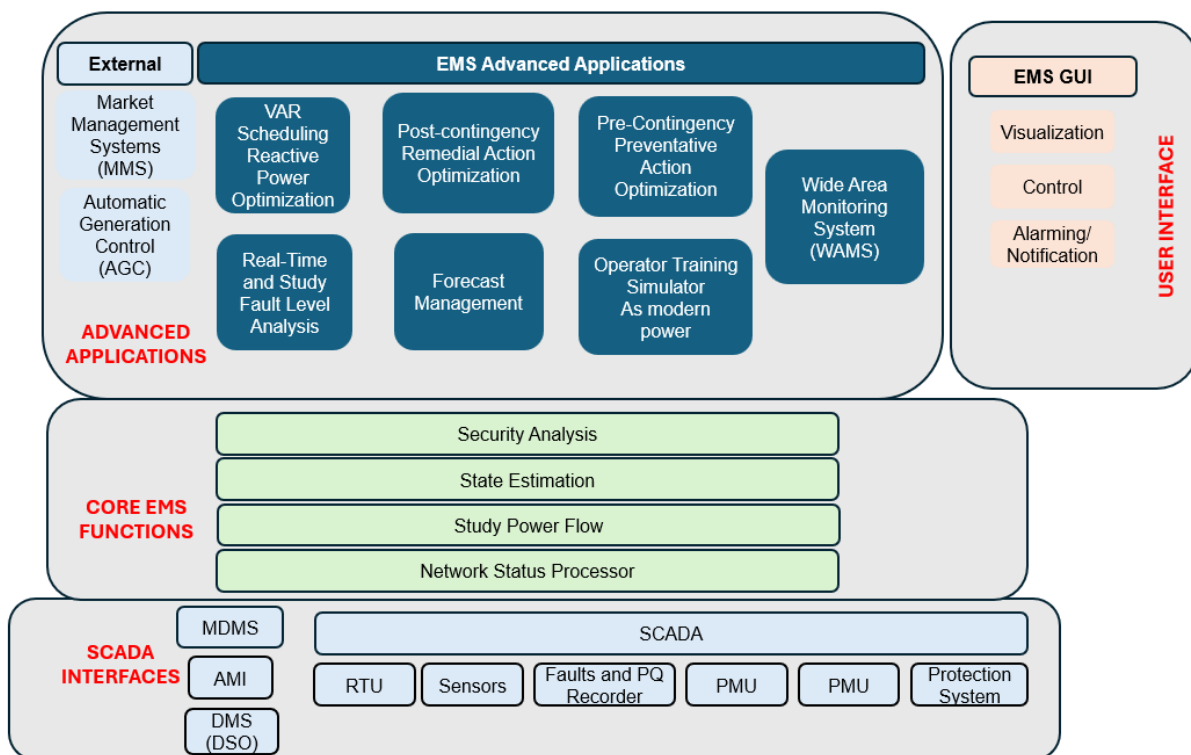


Figure 12 Example EMS architecture for a TSO, showing core and advanced functionalities integrated with SCADA interfaces.



### 2.6.1.1. EMS Core Functionalities

#### Network Status Processor

Network Status Processor (NSP) provides a precise determination of electrical connectivity at the individual bus section level. Rather than relying on user-defined calculations that must be maintained over time, NSP uses a detailed connectivity model in conjunction with generalized Boolean logic to accurately determine electrical connectivity and resulting energization status for each individual power system component.

#### Study Power Flow

Study Power Flow employs algorithmic methods—such as Newton and Fast-Decoupled techniques—to analyze the transmission network within the transmission system model. These power flow engines generate a base case offline solution, which serves as a foundation for conducting further studies and analysis.

#### State Estimation (SE)

SE processes measured data, equipment status, and network topology to estimate voltage levels, phase angles at all buses, and real and reactive power flows throughout the transmission system. It corrects for measurement errors and infers unmeasured states, creating an accurate, coherent and complete model of the system's current operating conditions. The output from SE serves as the baseline for other EMS functions and alerts operators to any violations of system limits, such as overloads, voltage deviations, or power transfer restrictions.

#### Security Analysis

This function assesses the system's resilience to potential disturbances by performing real-time contingency analysis (RTCA). Typically conducted every 1 to 15 minutes, RTCA simulates "what-if" scenarios including equipment outages or changes in power flows. Operators leverage these insights along with established operational guidelines to take corrective actions—such as generation adjustments, switching operations, or load curtailments—to maintain system stability. Contingency Analysis tools enable the evaluation of how topological changes or variations in generation output (MW) affect a base case solution. These tools support batch processing, allowing multiple contingency scenarios to be analyzed collectively. This provides users with the ability to assess the impact of numerous contingencies under defined system conditions efficiently.

### 2.6.1.2. EMS Advanced Functionalities

#### Voltage/VAR Scheduling Reactive Power Optimization

Constraint violations can be mitigated using various selectable objective function methods that leverage reactive power controls. Users have the flexibility to optimize either all system limits or focus specifically on reactive power constraints.



### Post-contingency Remedial Action Optimization

The remedial action module enables the generation of independently optimized corrective rescheduling plans for each harmful contingency identified through Contingency Analysis. For every identified case, the module determines a set of active and reactive power control actions that aim to minimize user-defined objectives while ensuring compliance with all enforced operating limits during the post-contingency period.

### Pre-Contingency Preventative Action Optimization

The preventative action module provides the capability to develop optimized scheduling strategies ahead of potential contingencies. It identifies a set of active and reactive power control actions that, when applied in the pre-contingency timeframe, ensure system security in the event of any listed contingency. The optimization process minimizes user-defined objectives while adhering to all enforced operating limits in both the base case and the contingency scenarios.

### Real-Time and Study Fault Level Analysis

Fault level analysis tools support both real-time and offline simulations of various fault types, including three-phase, phase-to-ground, phase-to-phase, and phase-to-phase-to-ground faults. These simulations can be performed using either user-defined or pre-configured fault scenarios within any active system case.

### Voltage and Transient Stability

The Voltage and Transient Stability analysis tools within the EMS enable TSOs to evaluate the system's ability to maintain stable voltage profiles and recover from disturbances such as faults, load fluctuations, or generator outages. These tools simulate the dynamic behavior of the grid over time and assess whether the system can return to a secure operating state. This functionality supports proactive decision-making and enhances system reliability under both normal and stressed operating conditions.

### Forecast Management

This employs data from Historical Information Systems (HIS) and weather forecasting to generate multiple forecasts critical for system planning and operation, such as:

- Short-term Load Forecasting
- Wind Speed and Direction Forecasting
- Renewable Generation Forecasting

### Operator Training Simulator

As modern power systems become increasingly complex due to higher integration of renewables, distributed resources, and advanced grid technologies, effective training tools are essential to prepare system dispatchers. This module offers a realistic simulation environment that reflects the intricacies of current grid operations. It enables operators to



build proficiency with advanced control functions, test new operational strategies, and practice managing emergencies, helping ensure reliable system management amid growing operational challenges.

#### Visualization and Situational Awareness

EMS provides operators with real-time displays of equipment status, alarms, and operational metrics. This visualization supports quick identification of system issues and facilitates timely intervention. Alerts for system violations and operational anomalies are presented through visual and audible alarms, enabling proactive management.

#### Automatic Generation Control (AGC)

AGC regulates the output of generators within a control area by continuously balancing supply and demand. It implements two core functions:

- **Load Frequency Control (LFC):** Maintains system frequency and scheduled power exchanges by calculating an Area Control Error (ACE) signal based on frequency deviations and tie-line flow imbalances, which directs generator output adjustments.
- **Security-Constrained Economic Dispatch (SCED):** Determines the optimal, cost-effective generation dispatch every 5 to 15 minutes, ensuring load is met without violating transmission constraints or operational limits. AGC delivers precise generation setpoints to maintain reliability and economic efficiency.

#### Wide Area Monitoring System (WAMS)

Incorporates synchrophasor technology and forecasting modules that enhance grid awareness and planning. WAMS utilizes high-speed, time-synchronized measurements to monitor wide-area voltage angles, system oscillations, damping, and islanding detection, contributing to improved dynamic stability monitoring.

- **Synchrophasor Integration:** Some EMS implementations integrate synchrophasor measurement technology, offering high-resolution, time-synchronized data across wide areas. This capability enhances monitoring of voltage angles, system oscillations, and islanding conditions, thereby improving the grid's dynamic stability and operational responsiveness.

#### Market Management System (MMS)

Often integrated with or closely connected to the EMS, the Market Management System (MMS) supports the operation and management of electricity markets. It facilitates market settlement and bid management while ensuring that market operations respect physical system constraints and security limits provided by the EMS. The MMS utilizes data from state estimation, security analysis, and forecasting modules to optimize market dispatch and pricing, balancing economic efficiency with system reliability.



To interface effectively with various regional market systems, the EMS offers flexible connectivity options. Typical market interfaces use ICCP data links to exchange primary data such as base points and net scheduled interchange, complemented by XML files as supplementary or backup communication channels. The system can operate either in full market mode or independently as a backup for regional market platforms. Given that market interfaces vary by region, the system is customizable to meet the specific requirements of each utility or market environment.

### **2.6.2. Distribution Management System (DMS) and Advanced Distribution Management System (ADMS)**

Moving closer to the end consumer, DMS enhance this functionality by offering advanced capabilities such as fault detection, isolation, and restoration, as well as voltage and reactive power optimization within the distribution network. Building further on these capabilities, integrate DER management and advanced analytics to enhance situational awareness, optimize grid operations, and meet the evolving demands of decentralized and renewables-rich networks.

While a SCADA system enables utilities to monitor and control end-use devices, a full DMS allows a dispatcher to securely and efficiently oversee and operate the distribution network. A DMS provides a real-time, centralized view of the distribution system and coordinates field operations to ensure a safe and efficient workflow. It stores technical data about substations and feeders, receiving near real-time field measurements from SCADA and other sources like Advanced Metering Infrastructure (AMI).

A DMS can be integrated with a variety of operational and enterprise-level systems. The specific systems it connects depend on the architecture of DMS deployment, which may support both client-based and web-based interfaces. Like other control systems, a DMS can store local data and computation results and may also interface with historian systems or other long-term data archiving tools. It may interconnect with multiple auxiliary or standalone subsystems. The overall DMS architecture can generally be categorized into two main components: the individual functional subsystems and the enterprise communication bus that enables data exchange among them. Figure 13 illustrates a representative DMS architecture, highlighting how a DMS can interact and operate with both internal utility systems and external platforms.



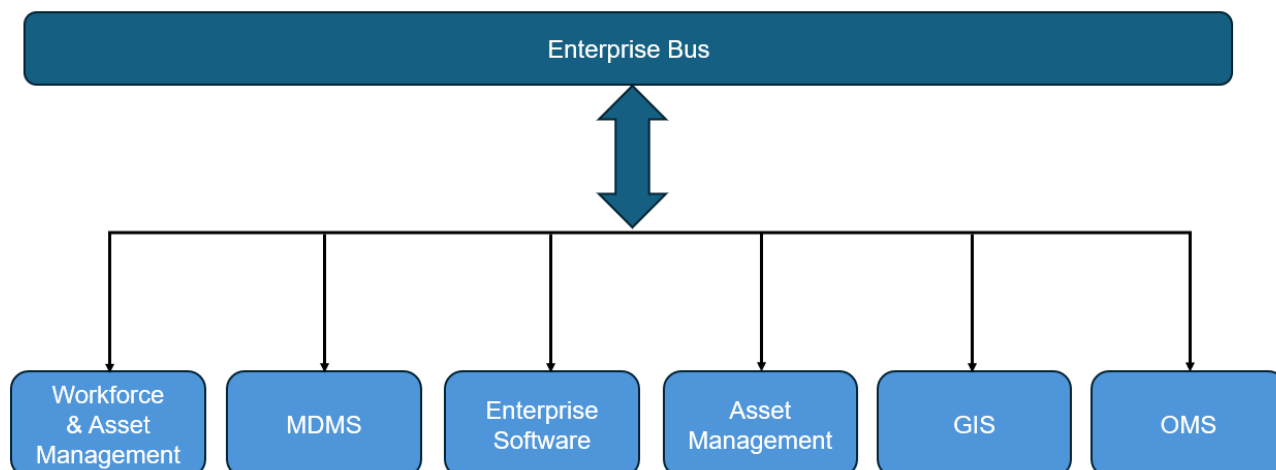


Figure 13. Illustrative DMS Architecture Showing System-Level Interoperability

At the core of a DMS is an operational power flow application, which uses SCADA measurements and the power system model to create a comprehensive view of the power flow in the network, viewable through an electronic map (Figure 14). Additionally, a DMS can include various analytic applications that process network model parameters and field measurements. These applications may encompass state estimation, fault location, and switch management, among others.



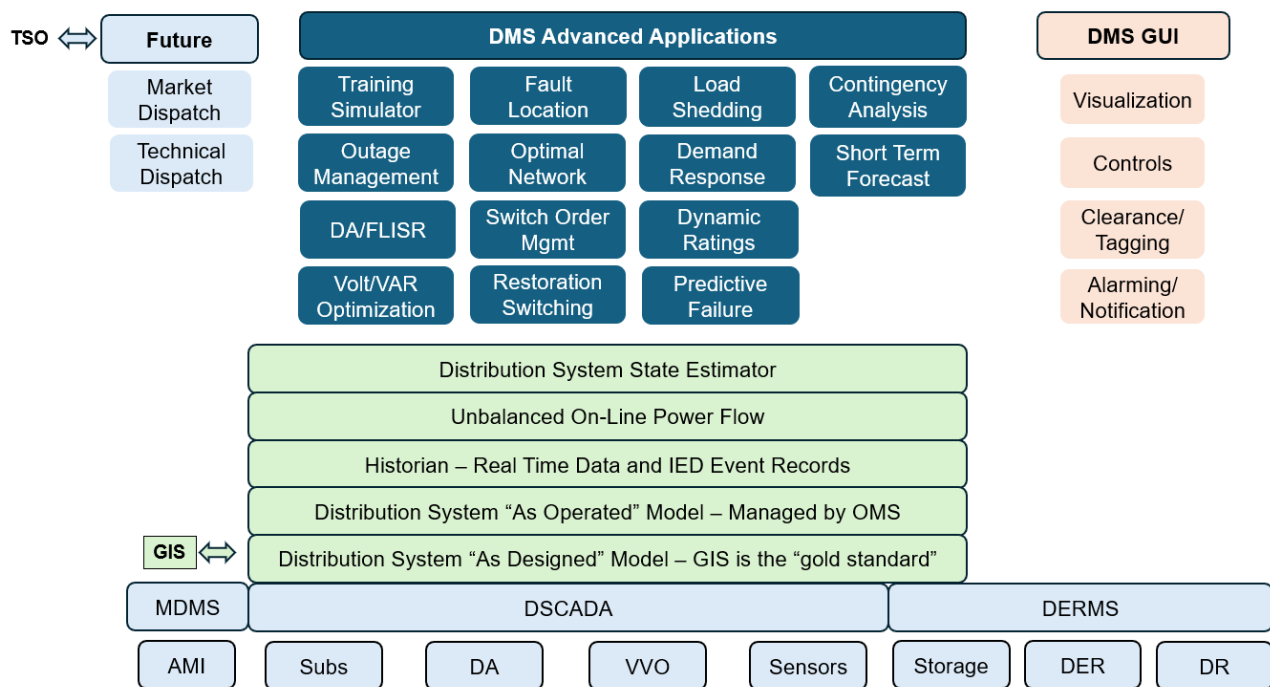


Figure 14. DMS Application Architecture

Utilities primarily implement a DMS to enhance system observability and controllability, thereby improving operational efficiency. An operational DMS includes various analysis packages that enable the utility to process field measurements and data for managing distribution system operations. The DMS Model serves as the central component, collecting information and facilitating control between the SCADA Interfaces and field components. It organizes this data according to the connectivity model from the GIS and the electrical parameters provided by the Asset Management systems. The core DMS functions act as the analytical engine driving the Advanced Applications, where the true value is realized. Additionally, the User Interface has evolved significantly, offering situational awareness and sophisticated visualization tools beyond a simple system window (Figure 15).





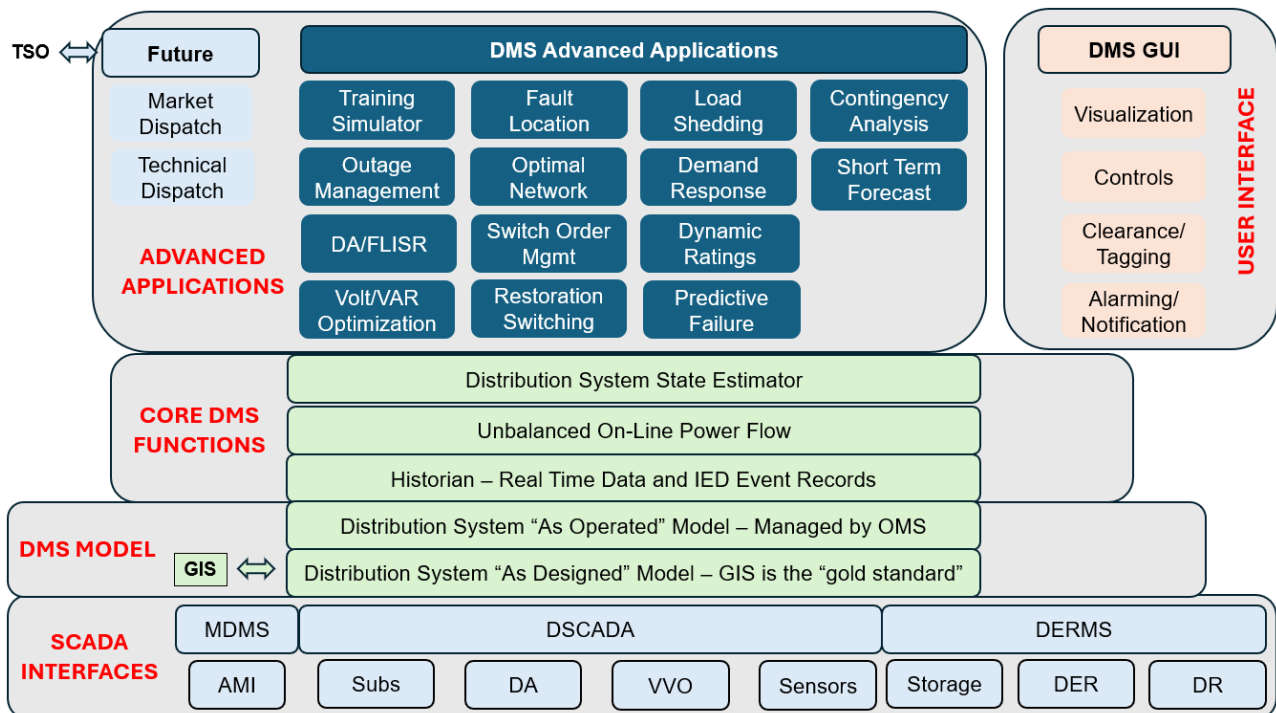


Figure 15. DMS Application Architecture - Broken Down by Areas

### 2.6.2.1. GIS / DMS Model

#### GIS

The fundamental component of all SCADA/DMS systems is the "As Designed Model." This model includes all elements such as conductors, switches, transformers, fuses, loads, and sources, along with the topology that connects them. Geographic Information Systems (GIS) are designed to store and display extensive geospatial asset data [5]. Engineers enter asset location information into a GIS by physically locating equipment or other assets and recording their spatial locations. Besides spatial data, equipment-specific information can also be stored. This data can then be used to display system information in a geospatially representative manner, providing a clearer view of the system state. The accuracy of GIS data, and consequently the network model, is crucial for all systems that depend on GIS input.

Before modern GIS, power companies relied on paper maps to track geospatial information, which was time-consuming to update and prone to errors that could pose safety risks for field workers. Over time, utilities transitioned to electronic databases and graphical representations. Modern GIS is typically an offline tool where data is entered by a field engineer or technician (also known as a "staking engineer") and used for multiple purposes. In addition to graphical representation and asset management functions, modern GIS can





provide input to the DMS, OMS, and CIS. The GIS system and its related asset systems are key enablers of electronic mapping.

GIS provides five key pieces of data:

- **Asset type:** What type of asset is it (e.g., circuit breaker, transformer)?
- **ID:** What is its name?
- **Location:** Where is it located (generally latitude/longitude coordinates)?
- **Connectivity:** What is it connected to?
- **Characteristics:** What are its characteristics (e.g., impedance)?

For utilities deploying a DMS or ADMS, GIS is a critical element representing the "system of record for the as-designed and as-built configuration," providing network connectivity and equipment information. GIS usage includes optimizing electric line routing, designing and locating new feeders and substations, and establishing the customer-to-network link. Regular GIS updates are integrated into the workflow at most utilities that have one.

A connectivity map (as shown in Figure 16) illustrates the interdependencies between GIS and other systems. This map represents how the DMS and the OMS are interconnected with the GIS to ensure accurate representation of distribution system model information. OMS data can be used to validate and cross-check GIS information. Additionally, GIS forms the foundation for utility planning models. While the connectivity map in Figure 16 is just a representative example, it underscores the importance of GIS as a key component in an integrated system.



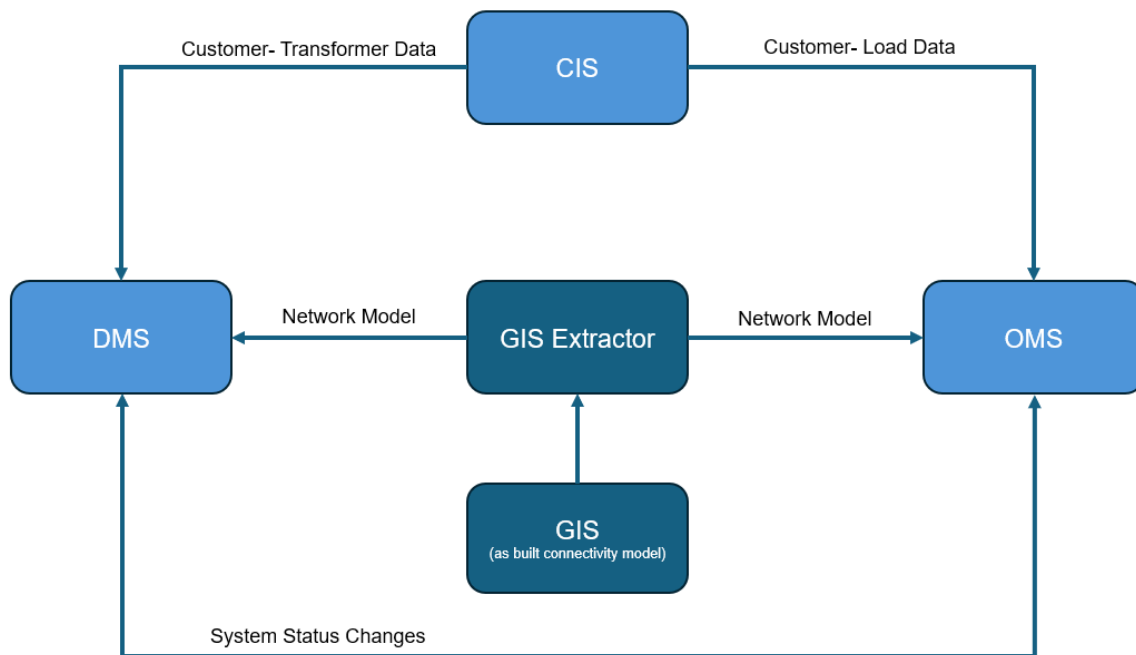


Figure 16. Reference Model for GIS and ADMS System Integration

### DMS Model

The DMS should feature a comprehensive, up-to-date electrical and connectivity model of the electric distribution system, as required by the DMS applications. There should be a single DMS model utilized by all advanced DMS applications, such as online power flow and short circuit analysis. This model should represent the entire distribution network, including distribution feeders and substation devices from the high-voltage side of the substation transformer (including the high side circuit breaker) down to the low voltage (secondary) side of the distribution service transformers. The DMS distribution system model should be a three-phase model that accurately reflects the unbalanced nature of the distribution system. It should encompass the entire distribution primary circuit, including main line portions, feeder laterals, and underground loops connected to the main trunk of the feeder. The model should accommodate three-phase portions of the feeder as well as single-phase and two-phase line segments and laterals.

While most feeders are typically radial, meaning there is only one path from a single feeder source to any point on the feeder, the DMS distribution system model and its associated application software should be capable of handling looped and weakly meshed feeder configurations, circuits operating in parallel, and secondary networks. The electrical model should encompass the entire electrical distribution system, including all elements from the transmission supply points (high voltage side of the substation transformers) to the low



voltage (load) side of the distribution service transformers. It's important to note that the demarcation line between transmission and distribution may vary between utilities.

The "As Operated Model" refers to the capability to accurately reflect all temporary changes in the system models, ensuring that the SCADA/DMS represents real-time conditions. This includes both automatic changes via remote controls and manual changes via manual controls. The DMS should facilitate the installation of temporary changes to the electrical model. It should allow for changing the open/closed status of a switch that is not automatically telemetered (pseudo point). Additionally, the DMS should support the addition of temporary cuts and jumpers, including those between individual phases. Operators should be able to modify the network model to show a feeder being cut, grounded, or connected (jumped) to another feeder or phase. Once repairs are completed, it should be possible to revert the network model to its original state. All such changes should be automatically updated in the DMS model. This functionality is typically managed by the OMS, which may be a DMS module or a separate integrated application.

#### *2.6.2.2. Outage Management System*

Outages in the distribution network can be either planned, for maintenance or new customer connections, or unplanned, typically caused by weather events, vegetation, or equipment failure. The primary function of an Outage Management System (OMS) is to monitor, analyze, and manage unplanned outages within a utility's distribution system. OMS also identifies affected customers, prioritizes restoration efforts, and estimates restoration times. The key OMS functionalities include [5]:

- **Outage Tracking and Management:** Maintains real-time status of switch positions to detect outage locations and ensure accurate outage reporting.
- **Call and Event Management:** Interfaces with the Customer Information System (CIS) to log trouble calls and receive smart meter outage alerts.
- **Incident and Crew Management:** Supports incident localization and efficient crew dispatch for both unplanned outages and planned maintenance.
- **Customer Information Sharing:** Maintains customer outage records and shares them with interconnected systems like the CIS or DMS.

Historically, OMS started as standalone systems managed manually through customer phone calls. With technological evolution, features such as touch-tone response systems and Interactive Voice Recognition (IVR) improved the volume and quality of customer outage data collection. By linking customer records from the CIS with network topology, utilities can map customers to specific transformers, enhancing the precision of outage location and crew dispatch.



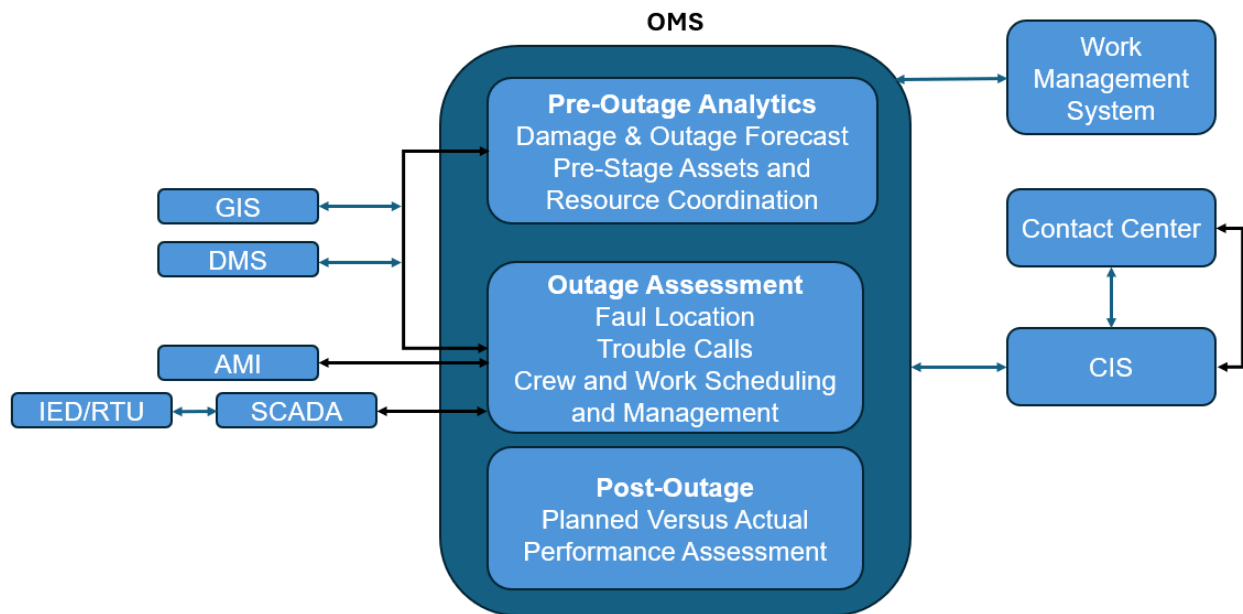


Figure 17. Example Architecture of an Outage Management System

Modern OMS relies on a logical connectivity model of the distribution system—typically derived from the GIS. GIS data provides an accurate geospatial representation of the network and is essential for visualizing and managing outage events. The OMS architecture often integrates inputs from AMR/AMI systems, customer calls, GIS, and DMS to create a comprehensive and real-time view of outages and restoration progress.

#### 2.6.2.3. DMS Core Functionalities

##### State Estimation

Real-time network monitoring is essential for achieving smart grid benefits. While On-Line Power Flow (OLPF) is useful for computational analysis and planning, it cannot monitor the system's exact state in real time. State variables, such as voltages and phase angles at each bus, are needed to calculate other parameters like current, power, and reactive power. However, measurement devices can have inaccuracies, bad data, or insufficient coverage, making it challenging to get accurate readings. State Estimation is a mathematical process that compares actual measurements to calculated expectations to determine the voltages, phase angles, and power flows. This process has been used in transmission operations since the late 1960s and is now needed for distribution systems. However, state estimation at the distribution level differs from the transmission level due to operational and infrastructural differences:

- Transmission networks have a mesh topology, while distribution networks are radial.



- In distribution systems, the density of measurement devices is usually insufficient to match the number of system states, limiting the ability to perform accurate state estimation. While some transmission areas may also have limited instrumentation, the lack of observability is more prevalent and challenging in distribution networks due to their scale, design, and historical absence of monitoring infrastructure.
- State estimation in distribution networks faces unique challenges due to a combination of factors. The radial topology, typical of most distribution systems, can significantly affect observability—especially when measurement data is sparse. In such cases, even the loss of a few key measurements can prevent accurate estimation of system states. Additionally, the low reactance-to-resistance (R/X) ratio of distribution lines complicates the application of traditional decoupled power flow methods. While modern algorithms can handle non-decoupled formulations, the low R/X ratio can still impact numerical stability and estimation accuracy, particularly when combined with uncertainties in line parameters and limited sensor precision.
- Switch states, capacitor bank states, and transformer/regulator taps may not be directly monitored.
- Distribution systems are often unbalanced.
- Historical load data is often used as pseudo-measurements.

#### On-Line Power Flow (OLPF)

The DMS must include an **On-Line Power Flow (OLPF)** program to determine the electrical conditions on distribution feeders in near real-time. The OLPF should provide control center personnel with calculated current and voltage values, replacing actual measurements, and alert operators to abnormal conditions like low voltage at feeder extremities and overloaded line sections. Additionally, other DMS functions such as Switch Order Management (SOM), Volt-VAR Optimization (VVO), and FLISR should utilize OLPF results for their operations. The OLPF should use the distribution system model, load estimates, and real-time statuses from substation and feeder devices.

#### Data Historian

This feature involves integrating with a Data Historian to support all critical SCADA/DMS applications. Since SCADA/DMS systems are secured behind firewalls within the Distribution Control Center, access to their valuable data is limited. The Data Historian, which includes a server, database, and user interface applications, provides insights into past activities and events of the electrical network.

The Data Historian stores analog values, status, alarm, and control data from various end devices monitored by the SCADA/DMS, such as RTUs, IED relays, DA controllers, and sensors. Each record is globally time-stamped for complex sequence of event analysis.



Typically, Data Historians use an exception storage scheme to compress digital and analog values, reducing the number of records needed to recreate a reasonable facsimile of the original data stream.

The DMS should incorporate a Historical Information System (HIS) to store and retrieve system variable values, alarm and event messages, power system disturbance reports, and other relevant information. Real-time data should be periodically stored in the HIS at user-defined intervals and on an exception basis when a variable changes by a specified amount. Event-related information, such as alarms or power system disturbances, should be recorded whenever these events occur.

#### 2.6.2.4. Advanced Functionalities

##### Short-Term Load Forecasting

This feature ensures integration with a Load Forecasting Solution to support all critical SCADA/DMS applications. The DMS should include a Short-Term Load Forecast (STLF) function that uses historical load and weather data to automatically forecast system load (e.g., every hour for a 168-hours - 7 days). Weather data supports this function, and the STLF results are available for viewing, outage planning, and use by other DMS applications requiring near-term peak load estimates, such as FLISR, Switch Order Management (SOM), Network Reconfiguration, and Large Area Restoration.

The STLF employs both weather-adaptive and similar-day forecast methodologies to achieve accurate predictions. Weighting factors can be assigned to each methodology's results to obtain a weighted average forecast. The load forecast is based on historical load measurements or future actual meter readings from AMI for the specified feeder on a similar day in recent years. Similar days are selected based on the day of the week (weekend, holiday) and month or season.

##### Fault Location, Isolation and Service Restoration (FLISR)

FLISR is a set of automated solutions that enable the system to automatically locate permanent faults, operate MV switches to isolate the fault, and propose or perform MV switching to restore service. This applies to both American (grounded neutral) and European (isolated or impedance grounded neutral) MV configurations.

The SCADA/DMS should autonomously perform the necessary switching maneuvers to isolate an MV fault between two automated switches and restore service to the maximum number of customers before the outage is classified as a sustained event (typically 5 minutes in North America, 3 minutes in Europe) [16], [17]. The process includes:

- **Fault Location:** Fault detection sensors identify the fault location immediately after it occurs.



- **Fault Isolation:** MV switches/breakers automatically open to isolate the fault between two automated switching devices.
- **Service Restoration:** This involves upstream restoration (reclosing the primary substation circuit breaker or other protective device to restore customers upstream of the fault) and downstream restoration (automatically closing a normally open tie switch to restore customers downstream of the fault).

The SCADA/DMS should also adapt to temporary topology changes due to planned work or previous faults, ensuring the FLISR logic can perform as effectively as an experienced control room operator with remote control capabilities. This requires a high level of flexibility, adaptability, and situational awareness.

### Vol/VAR Optimization

Volt/VAR Optimization (VVO) is a comprehensive set of automated solutions designed to regulate MV voltage and VAR flow, enabling Conservation Voltage Reduction and controlling the operation of Distributed Energy Resources. The DMS should include a VVO function that automatically determines optimal control actions to achieve specified objectives while maintaining acceptable voltage and loading at all feeder locations. It should also adhere to utility constraints, such as limits on tap changer and capacitor bank operations.

Key utility-selectable objectives for VVO include:

- Reducing electric demand
- Reducing energy consumption
- Improving feeder voltage profile
- Maximizing revenue
- Minimizing energy loss/improving power factor
- A weighted combination of the above

The VVO function should operate in either closed-loop or advisory (open-loop) mode. In advisory mode, it generates control actions for dispatcher implementation, while in closed-loop mode, it executes optimal control actions automatically. VVO should run periodically, upon specific events, or manually by the user. The VVO function must have a failsafe design to prevent unacceptable voltage or loading conditions due to any DMS component failure. If a VVO component is out of service, the DMS should continue to operate without causing unacceptable conditions, using the remaining components.





### Planned Switching

Switching Order Management (SOM) supports the process of planning and executing switching changes on the distribution system for maintenance, network reconfiguration, restoration of unplanned outages, and new construction. It involves issuing Safety Documents to work crews to confirm that the specified network portion is safe and no longer under normal operation. The core of SOM is the Switching Order, a structured list of procedures used to coordinate switching between the control room dispatcher and field crews.

The SCADA/DMS should include a SOM function to assist the dispatcher in preparing and executing switching procedures for various power system elements, ensuring compliance with safety policies and work practices. The SOM function should support the creation, execution, display, modification, maintenance, and printing of switching orders, which include actions like opening/closing switches, implementing cuts and jumpers, blocking, grounding, and tagging.

The SCADA/DMS should also be capable of automatically generating switching orders. Dispatchers can select the power system device or portion to be isolated and worked on. Switching orders can be executed in real-time for supervisory control commands or in study mode to assess potential impacts on the power system using the DMS OLPF program.

SOM covers the entire switching process, including:

- Fast and accurate creation of Switching Orders from the network geographic view.
- Simulation of Switching Order execution against a study model based on projected conditions.
- Managing execution by verifying each step's completion.
- Placing tags on the geographic network view to match field tags.
- Saving and retrieving Switching Orders for record-keeping and later use, including "macros" and "templates."
- Automated creation of a draft "Back-out" Switching Order to return the network to its original state.
- Allowing dispatchers to modify partly executed Switching Orders in case of equipment failure or unexpected problems, maintaining an accurate record of actions taken.

### Emergency Load Shedding

The Emergency Load Shedding (ELS) function in a DMS is designed to prevent cascading events and system blackouts by automatically shedding load in real-time. This function





should work in sync with other load shedding mechanisms, such as under-frequency and under-voltage load shedding, to minimize manual intervention and restore previously shed load once the issue is resolved. Users can initiate load shedding for loads within their assigned Area of Responsibility (AOR).

When activated, the ELS function determines which switching devices to operate to achieve the load shedding goal. The North American Electric Reliability Council (NERC) has highlighted several key lessons from load shedding events, including the importance of periodic operator training, identifying sufficient load circuits for manual shedding, and having operational tools and SCADA displays to track load shed outages [18]. Automated load shedding applications that rotate load feeders on a timed basis should be evaluated. Registered entities should regularly review and update circuit data, maintain communication processes with local agencies, and have outage area maps readily available for management and stakeholders.

### Training Simulator

The Operator Training Simulator (OTS) function in a DMS provides a realistic environment for hands-on dispatcher training under simulated normal, emergency, and restorative conditions. It includes a complete replica of the real-time DMS user interface and operating model, simulating real-time telemetry and status changes. The OTS serves two main purposes:

- Familiarizing utility personnel with the DMS system and its user interface without affecting actual operations.
- Helping personnel understand the dynamic behavior of the electric distribution system during manual and automatic actions under various conditions.

The OTS goes beyond simple data playback by simulating the power system's behavior under normal and simulated disturbances. Starting from a specific system snapshot, it fully emulates real-time monitoring and control capabilities, including alarming, tagging, and AOR functionalities.

The simulator includes dynamic modelling to simulate the distribution system's expected behavior in response to disturbances. It uses either the real-time model from the control center or selected saved cases, displaying dynamic load models and forecasted feeder loads as if they were actual field measurements. Instructors can introduce equipment and control failures, and the simulator will calculate and present the expected results to trainees. They can also place simulated faults at any location along the feeder, with the simulator displaying the expected fault current magnitude and protective device operations. This comprehensive training tool enhances safety, reliability, and operational effectiveness.



### Optimal Network Reconfiguration

The Optimal Network Reconfiguration (ONR) function in a DMS analyses real-time conditions using online power flow to optimize objectives such as minimizing losses and improving reliability. It identifies ways to reconfigure a user-selected set of distribution feeders to achieve a specified objective without violating loading or voltage constraints. Users can select the entity for ONR, such as a division or a single substation.

The ONR function should enable users to:

- Minimize total electrical losses over a specified period.
- Minimize the largest peak demand among the selected feeders over a specified period.
- Balance the load between feeders by transferring load from heavily loaded to lightly loaded feeders.
- Combine the above objectives with weighting factors.

The ONR output includes recommended switching actions, a switching plan, and a summary of expected benefits, such as loss reduction.

### 2.6.3. Advanced Metering Infrastructure

Automated Meter Reading (AMR) systems, first deployed in the early 1990s, introduced automated energy consumption data collection with one-way communication for billing purposes. Advanced Metering Infrastructure (AMI), which became widespread in the mid-2000s, offers enhanced capabilities, including two-way communication that enables remote control, pricing updates, demand response, and outage notifications [19].

To manage the large volumes of data generated by AMR and AMI, utilities use Meter Data Management Systems (MDMS), which store, validate, and process meter data—primarily for billing, but also for integration with other systems like DMS, OMS, GIS, and CRM (Figure 18). AMI and MDMS together enable more dynamic grid operations and customer interaction, though they also introduce significant data handling and privacy challenges.

A typical architecture involves smart meters sending consumption data (e.g., every 5 or 15 minutes) via wireless or fiber-optic networks to the MDMS, where the data is validated and processed through a billing workflow.

Data collected through AMR or AMI systems and processed by the MDMS can be leveraged by other utility systems to enhance distribution system operations. For instance, an AMI system—either directly or via the MDMS—can send a "last gasp" signal to the Outage Management System (OMS) when a meter loses power due to an outage. This signal helps



the OMS quickly detect and localize the outage, enabling a faster response and restoration. Additionally, operators can remotely "ping" individual meters or groups of meters to verify their power status, confirming whether they are online or offline.

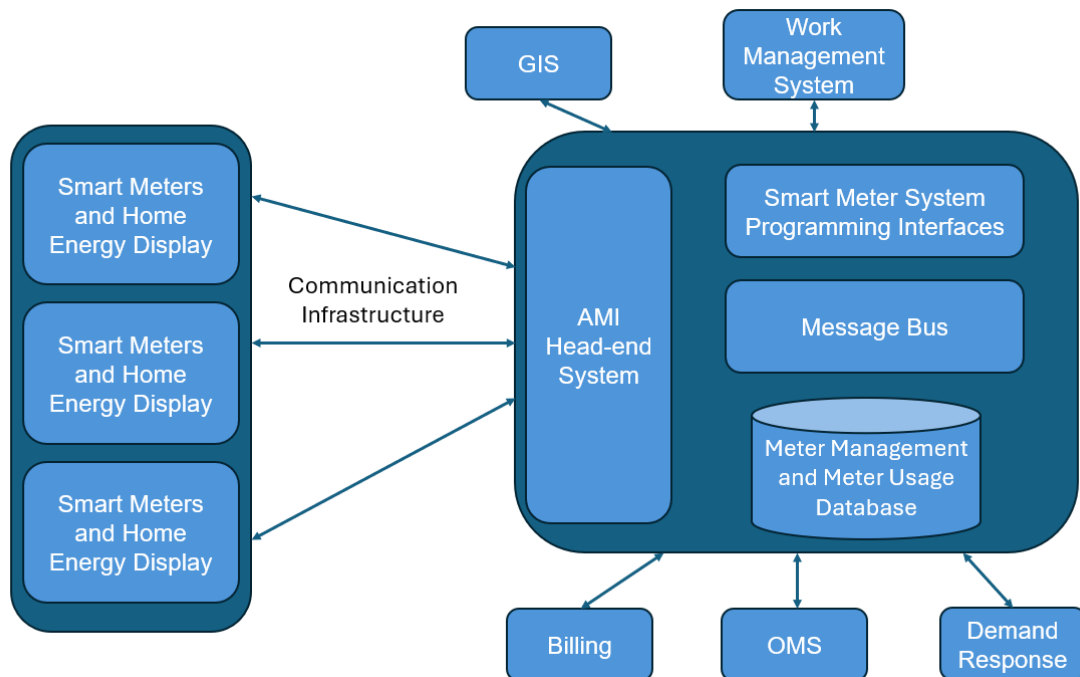


Figure 18. Illustrative Architecture of AMI and MDMS Integration

Integrating an OMS with a DMS requires two-way communication between the platforms. While guidelines recommend bidirectional data exchange, in practice, utilities often limit automatic updates from OMS to DMS, preferring that any data transfer be reviewed or initiated by operators.

Effective OMS–DMS integration can offer substantial benefits—particularly when DMS data provides actionable insights for dispatchers or automated decision-making. However, the integration's value depends on data accuracy and system coordination. For instance, during Superstorm Sandy (2012), some utilities reported widespread outages without the ability to precisely locate fault sources, underscoring the importance of accurate network connectivity data in OMS performance [5].



Table 3. Example of Data Exchange Between DMS and OMS Systems

OMS	Data Flow	DMS
Upgrade grid topology based on manual operations performed by the operator and executed in the field by the crew.	←	Switching actions initiated by operators and automated control systems.
Estimation of fuse or local automatic switch status using trouble call data.	→	Update the status of the specified fuse and local automatic switch.
Forecast customer outages using DMS planning data.	←	FLISR and other scheduled switch operation plans
Issue switch commands and estimate repair durations for DMS operations	→	Carry out automatic switch commands from the OMS

OMS effectiveness also improves when combined with AMR or AMI data. These data streams help to ensure that customer locations in the GIS are properly aligned with records in the CIS. Additionally, AMI–OMS integration can support restoration verification by confirming when meters come back online. Similarly, integrating OMS with SCADA allows for automated detection of outages and restorations based on field device measurements—such as voltage regulators, reclosers, shunt capacitors, and other remotely monitored equipment

#### 2.6.4. Distributed Energy Resource Management System

The increasing penetration of DERs is introducing new economic and technical challenges for distribution systems. In response, Distributed Energy Resource Management Systems (DERMS) have emerged as a promising solution for managing a variety of DERs—including EVs, DG, demand response, and energy storage systems.



DERMS platforms can function as standalone systems or be integrated into broader systems such as the DMS. Their architecture and functionality vary significantly across vendors, reflecting the diverse roles DERs play in grid operations and their differing interactions with utilities. As a result, DERMS implementations are often highly customized to meet specific operational requirements and utility needs.

A DERMS may support a wide range of distribution system and DER management objectives, including but not limited to [20]:

- Management of distributed energy storage systems
- Coordination of distributed electric vehicle charging
- Monitoring and control of distributed solar generation
- Dispatch and control of non-renewable distributed generation resources
- Demand response management, including integration with Building Energy Management Systems (BEMS) and coordination with transmission-level load shedding programs

In terms of system integration, DERMS platforms typically interface with various utility systems such as DMS, MDMS, GIS, and CIS. They can exchange real-time DER operating status with DMS or SCADA systems and receive control instructions in return.

Figure 19. Example Architecture of a Distributed Energy Resource Management System

illustrates a representative architecture of a DERMS and its key system interactions. This figure also illustrates a use case of a DERMS in the context of electricity markets. In this scenario, market platforms and DER trading systems exchange contractual and operational information with both the DMS and DERMS. A DERMS can also interface—via SCADA and AMI—with Home Area Networks (HANs), Building Energy Management Systems (BEMS), and DER aggregators. This positions the DERMS as a key coordination platform linking distributed resources, end users, and market systems.

The nature and scope of data exchange between DERMS and other systems depend on the system architecture, the functions it supports, and the types of DERs present in the utility's service area [20]. A major factor influencing DERMS design is DER ownership: while some DER assets like distributed generation (DG) or storage may be utility-owned, most residential DERs—such as rooftop solar—are owned by customers or third parties. As a result, DERMS architectures are highly variable.

When integrated with the DMS, a DERMS can provide data on active and reactive power injections from DERs at their points of common coupling (PCC). To manage scalability and complexity, DERMS platforms often communicate with aggregators rather than with individual DERs, significantly reducing the number of direct data connections. Ultimately,



the design and data exchange strategy of a DERMS must align with the utility's operational goals and regulatory framework.

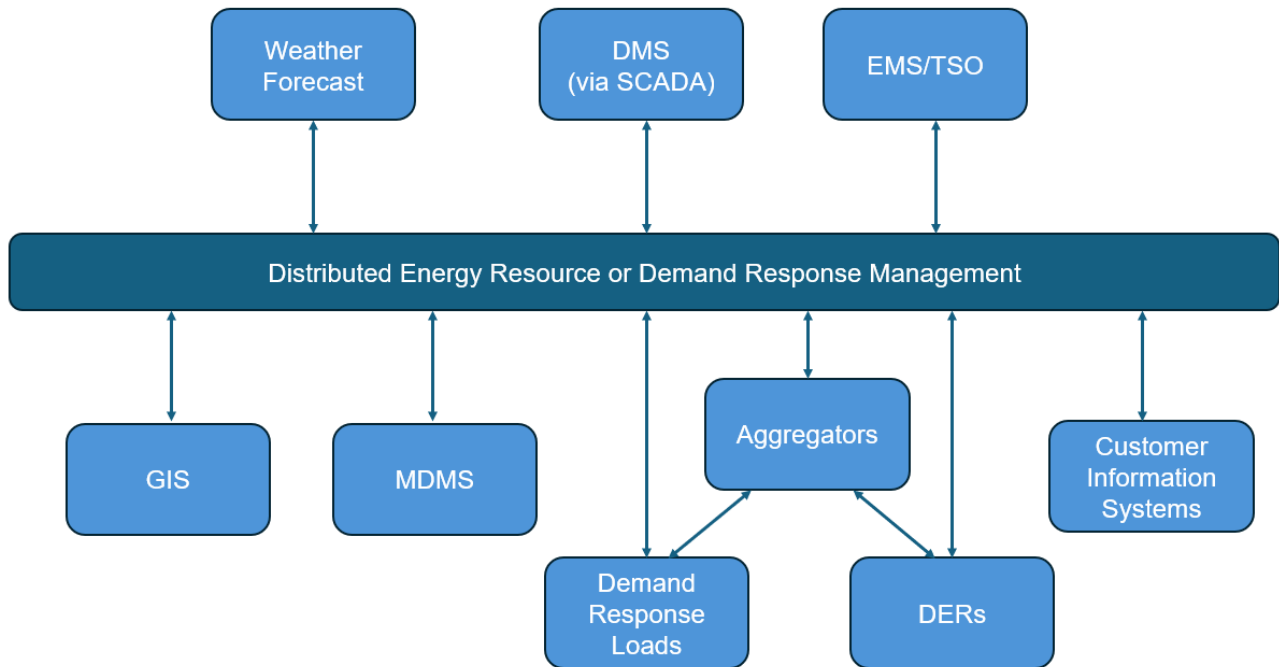


Figure 19. Example Architecture of a Distributed Energy Resource Management System



## 3. Open Architectures

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### 3.1. Barriers to Openness in Control System Architectures

SCADA/EMS/ADMS providers are understandably protective of their advanced control algorithms and methods, often keeping them entirely confidential or sharing them with customers only under strict non-disclosure agreements (NDAs). This is due to the significant investment required to develop these sophisticated algorithms, which serve as crucial differentiators in the competitive market.

As power systems become increasingly complex, incorporating more sensors, control elements, DC technologies, and DERs, the control methods must also evolve in complexity and diversity. Each feeder presents unique challenges, necessitating custom control methods in addition to the standard built-in methods provided by the SCADA/EMS/ADMS.

Utilities may not have the capability to independently develop and implement control algorithms, prompting SCADA/EMS/ADMS providers to offer customization services. As grid conditions change, these algorithms may need to be frequently modified to remain effective. Consequently, the number of unique control strategies employed to manage the distribution system increases over time.

This situation poses a significant challenge for the utility's ability to fully comprehend how the system is managed and to independently modify and adapt it in the future. Regardless of the level of transparency provided regarding the control algorithms, there is no straightforward method to transition to a new or different SCADA/EMS/ADMS while preserving the cumulative investment made. This results in a captive-customer scenario, which is incompatible with the utility's need for independence, especially given the mission-critical nature of DMS.

### 3.2. Potential Solutions

A potential solution to this issue is to establish a mechanism that allows transmission and distribution system control methods to be independently developed and transferred between systems. Similar to how a mechanic can transfer all their tools to a new toolbox, the cumulative investment made by the utility in distribution control methods could be preserved, enhanced, and carried forward. This is usually referred to as the concept of an "Open Architecture" for SCADA/DMS/EMS.



Figure 20 illustrates an example reference architecture for DMS systems. A similar architectural framework can be applied to EMS systems, reflecting common design principles and functional components across these energy management platforms. At the bottom are the I/O, data, and control interfaces. In the middle, shown in green, are the core DMS functionalities. At the top, in blue, are the control applications. In this illustration, each application is depicted as a single box, but as mentioned earlier, a specific application like volt/var optimization might have multiple versions to meet the needs of different circuits.

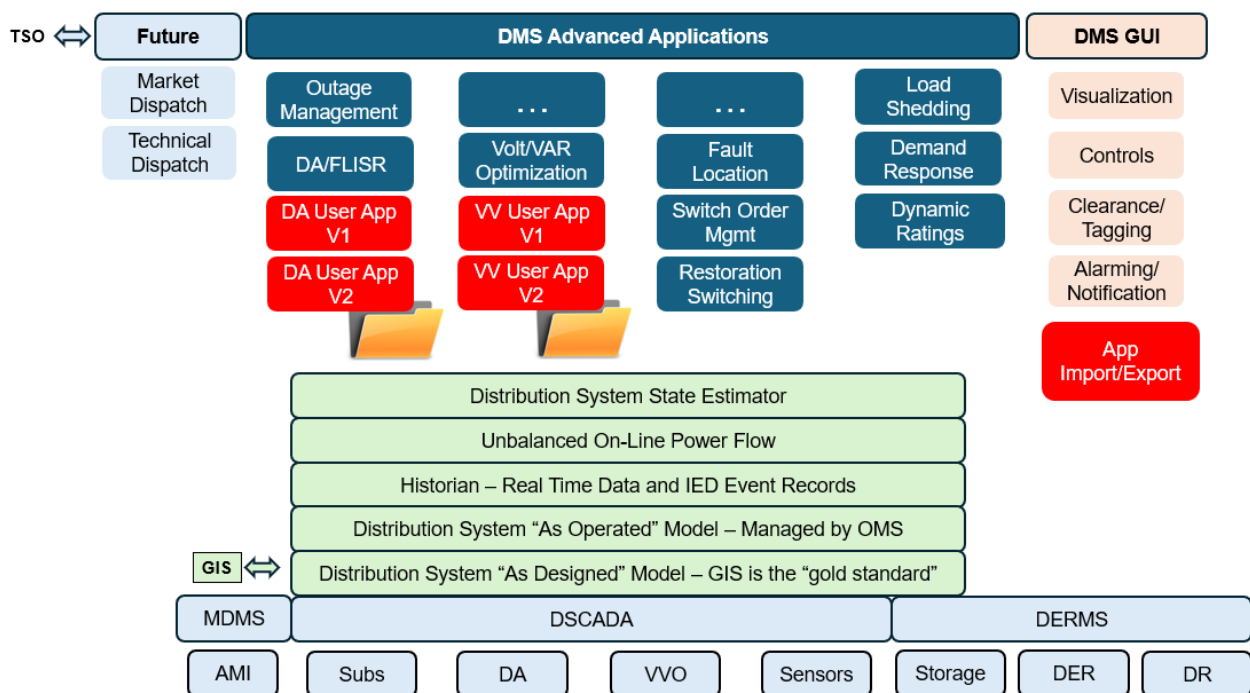


Figure 20. Example reference architecture for DMS systems

### 3.2.1. Control Algorithm Visibility and Development Capability

A primary objective of an open architecture for SCADA/EMS/DMS is to provide utilities with transparency regarding the control algorithms used to operate their circuits. This includes detailed technical aspects such as the sensor measurements utilized, required accuracy, applied filters and range limits, reference curve-fitting, interpolation and extrapolation of points, and decision-making trees (flow charts). Transparency fosters a deeper understanding of system operation, enabling utilities to make informed decisions about customization, integration, and vendor selection. This greater insight can expand business opportunities by facilitating innovation, interoperability, and the adoption of new technologies tailored to specific utility needs.





In addition to visibility into vendor-provided advanced control algorithms, an open architecture may grant utilities the freedom to independently create and integrate new advanced control algorithms into the DMS. This is depicted in the red shaded elements in Figure 20, which illustrate the potential for both internal (vendor-provided) and external (user-produced) algorithms. Utilities, along with their trusted partners, could develop an increasing number of tailored control algorithms to address the unique needs of specific circuits.

Even if internal advanced control algorithms are not fully transparent, the ability to independently develop new algorithms could provide the flexibility utilities need to address critical issues promptly and cost-effectively, and to devise solutions for unique problems that the DMS provider may not be interested in or capable of supporting. Many innovations initially arise from utilities locally developing and deploying specific solutions for specific problems. Without the ability to develop tailored DMS solutions, innovation is hindered, and the industry as a whole is constrained. Ultimately, the utility could decide the extent to which they utilize vendor-provided versus self-produced algorithms.

### 3.2.2. Transferability and Access Rights of Control Algorithms

While access to view, understand, and develop SCADA/EMS/DMS control algorithms is essential, it does not inherently guarantee their portability or reusability. Achieving these capabilities requires a standardized structure for control algorithms and a robust interface that enables the seamless integration of new control strategies into relevant circuits.

This interface must be capable of managing complex tasks, such as mapping control points and sensor data streams between the system (e.g., GIS data) and the control logic. Furthermore, the control algorithms must be able to interact dynamically with core SCADA/EMS/DMS functionalities, including system state estimation and power flow analysis. To support this vision, several critical components must be addressed through standardization:

- **Technical Approach** - Two primary approaches can be considered:
  - **A simplified model** retains all computation within the SCADA/EMS/DMS, with user input limited to configuration parameters—such as sensor selection, operational goals, constraints, and predefined calculations. While straightforward, this method restricts flexibility to only those capabilities originally built into the SCADA/EMS/DMS.
  - **A more advanced model** treats user-defined controls as modular applications, complete with executable code and settings. This approach offers significantly greater flexibility but necessitates a standardized runtime environment for these applications.



- **Interface Definition** - Regardless of the chosen technical approach, a standardized interface—often referred to as an Application Programming Interface (API)—is essential. This interface governs how control algorithms are imported into and exported from the SCADA/EMS/DMS. This promotes long-term reuse and protects the utility's investment in developing a library of control strategies.
- **Development Tools/Frameworks** - Standardizing both the technical framework and interface opens the door for third-party development tools. While DMS vendors may offer their own tools, broader standardization encourages participation from specialized developers, academic institutions, and consultants. This can lead to more user-friendly, accessible, and innovative development environments.
- **Ongoing Maintenance and Governance** - Like all standards, those governing SCADA/EMS/DMS control algorithms must evolve to meet changing industry needs. This requires active oversight by recognized standards organizations (e.g., IEEE, IEC) to ensure inclusive participation, transparent governance, and continuous refinement. Although utilities should ideally retain ownership of their control methods, proprietary software environments may impose restrictions. In some cases, access to control algorithms may be granted only under legal agreements that limit future use or redistribution.

### 3.3. Open Environment

As illustrated in the Figure 21, achieving interoperability—positioned at the center of the chart—requires coordinated progress across four key domains: the core SCADA/EMS/DMS platform, the control algorithms it runs, the development tools used to build and integrate those algorithms, and the role of algorithm developers, whether in-house, third-party, or vendor-based. The figure emphasizes the importance of decoupling the platform from the control logic, which promotes visibility, flexibility in development, algorithm portability, and clear usage rights. Together, these elements form the foundation of an open and interoperable environment for grid management systems.



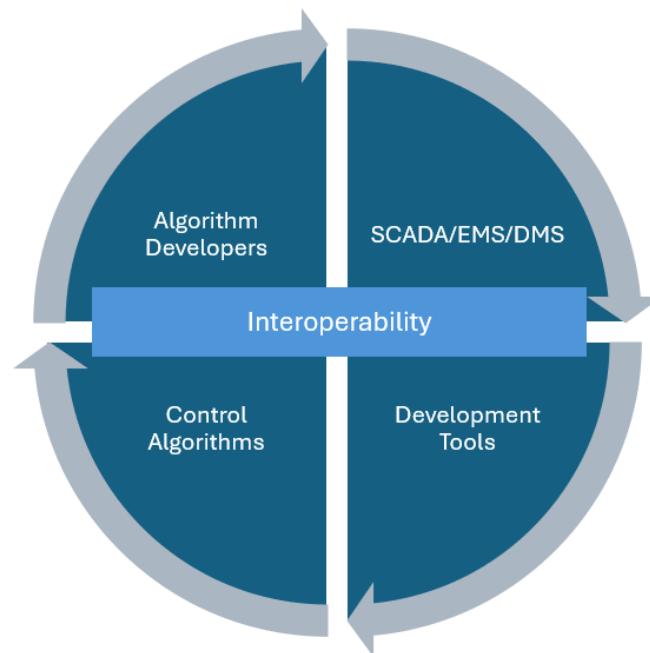


Figure 21. Overview of an Open Architecture for SCADA/EMS/DMS Platforms

In such an environment, the DMS or EMS serves as the foundational platform. It manages the distribution system model, provides large-scale visualization and operator interfaces, facilitates real-time communication with field devices, and executes the selected control algorithms for each feeder. However, the control algorithms themselves are treated as distinct components—akin to applications running on a smartphone. This separation allows users to view the platform and the control applications as independent investments.

This does not preclude SCADA/EMS/DMS vendors from continuing to offer control algorithms. Given their expertise and current market role, it is likely they will remain key providers of both core platforms and control solutions. However, the open architecture ensures that they are no longer the sole source. Utilities gain the flexibility to source control applications from a variety of providers—including third-party vendors, contractors, or through in-house development—and can negotiate usage rights as part of the procurement process. For SCADA/EMS vendors, adopting an open architecture approach can broaden market opportunities by enabling easier integration with other systems, promoting interoperability, and facilitating customization to meet diverse utility requirements. This openness encourages innovation by allowing vendors to develop specialized or advanced modules that can be easily integrated, fostering a competitive environment that rewards creative solutions and rapid technology advancement. Additionally, vendors benefit from reduced barriers to entry in utility markets, enabling them to offer more tailored and scalable solutions that address evolving industry needs, ultimately driving continuous improvement and differentiation.



An open SCADA/EMS/DMS environment also fosters industry-wide innovation. Utilities can share their internally developed control solutions with others, while also benefiting from the creative advancements made by peers. This collaborative ecosystem encourages the development and dissemination of high-value, field-tested control applications, ultimately accelerating progress across the sector.

A variety of open-source platforms and initiatives support the development of open, interoperable environments for SCADA, DMS, and DERMS systems. These platforms differ in focus and maturity but collectively illustrate the evolving ecosystem of modular and flexible grid solutions. Additionally, various research and innovation initiatives continue to develop and enhance these open-source tools to address emerging grid challenges, promote interoperability, and enable utilities to adopt more flexible, vendor-neutral control architectures. Some of these initiatives are briefly enumerated in the following points:

- **Real-Time Operation & DER Management**
  - Platforms such as **SOGNO**<sup>1</sup> [21], **OpenEMS**<sup>2</sup> [22] , and **RIAPS**<sup>3</sup> [23] enable real-time data exchange and decentralized control, making them well-suited for managing DERs at the grid edge.
  - **OpenSCADA**<sup>4</sup> [24] and **OpenMUC**<sup>5</sup> [24] provide real-time monitoring and device communication capabilities, often serving as flexible gateways or data acquisition layers within control systems.
- **Simulation and Co-Simulation Tools**
  - Tools like **OpenDSS**<sup>6</sup> [25], **GridLAB-D**<sup>7</sup> [25], and **FNCS**<sup>8</sup> [25] focus on simulation, analysis, and training. These platforms help utilities and researchers model control strategies and validate DER integration scenarios, although they are not intended for real-time operation.
- **TSO-DSO Coordination**
  - Platforms such as **SOGNO**, **OpenFMB**<sup>9</sup>, and **RIAPS** offer features to support coordination between transmission and distribution operators, using

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<sup>1</sup> **SOGNO** (Smart mObility and Grids Open, Networking and Operation)

<sup>2</sup> **OpenEMS** (Open Energy Management System)

<sup>3</sup> **RIAPS** (Resilient Information Architecture Platform for Smart Grid)

<sup>4</sup> **OpenSCADA** (Open Supervisory Control and Data Acquisition)

<sup>5</sup> **OpenMUC** (Open Metering and Utility Communication)

<sup>6</sup> **OpenDSS** (Open Distribution System Simulator)

<sup>7</sup> **GridLAB-D**- An advanced distribution system simulation environment widely used for research and pilot projects.

<sup>8</sup> **FNCS** (Framework for Network Co-Simulation)

<sup>9</sup> **OpenFMB** (Open Field Message Bus)



standardized protocols like IEC 61850, DDS, and MQTT to facilitate secure, interoperable communication.

- **SCADA/DMS/EMS Integration**

- **OpenFMB, OpenSCADA, and OpenMUC** Fabric provide middleware and translation services that allow modern digital assets to interface with legacy SCADA/DMS/EMS systems, enabling utilities to upgrade infrastructure incrementally.

- **Standards and Protocols Support**

- These platforms support a wide range of protocols, including IEC 61850, Modbus, OPC UA, MQTT, REST APIs, and others. For example, CoMPAS (Linux Foundation Energy) specializes in IEC 61850 and Substation Configuration Language (SCL), aligning with substation automation needs.
- Support for such standards is essential for interoperability, futureproofing, and vendor independence in utility automation.



## 4. Hybrid AC/DC Systems

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### 4.1. DC Technology

Modern DC technology is increasingly being implemented in power systems to address emerging challenges in transmission efficiency, integration of renewable energy, and the evolving nature of electrical loads. The resurgence of DC - after being historically supplanted by AC due to the ease of voltage transformation and long-distance transmission - stems from significant advancements in power electronics, materials, and control systems.

HVDC systems are now a cornerstone in bulk power transmission, offering distinct technical advantages over AC systems, particularly for long-distance and submarine cable applications. DC systems exhibit lower line losses due to the absence of reactive power, skin effect, and charging currents, enabling higher transmission efficiency and better controllability of power flow. Moreover, modern Voltage Source Converter (VSC) based HVDC technology allows for independent control of active and reactive power, black-start capability, and seamless integration with weak AC networks, making it especially suitable for interconnecting asynchronous grids and integrating offshore wind farms.

At the distribution and end-user level, Low Voltage DC (LVDC) and Medium Voltage DC (MVDC) systems are gaining traction due to the increasing prevalence of DC-native loads and sources—such as photovoltaic (PV) systems, battery energy storage, electric vehicle (EV) charging infrastructure, and power electronics-based devices. In fact, in recent years, the continuous rise in Distributed Generation (DG) installations within distribution grids has been driven by the decentralization of energy management and the overall increase in electricity demand. This demand has been further intensified by the electrification of transportation (e.g., electric vehicles) and temperature control in buildings (e.g., heating and cooling with the growing use of heat pumps). These developments are creating significant challenges for power quality and control in electrical grids. To address these issues, upgrading AC distribution networks with DC technology, utilizing power electronics components, presents a viable solution, resulting in hybrid AC-DC grids. By minimizing conversion stages, modern DC distribution networks can achieve higher overall system efficiency, reduce electromagnetic interference (EMI), and simplify system architecture.

The implementation of modern DC technology is also driven by the flexibility it offers in developing resilient and scalable microgrids, supporting both grid-connected and islanded modes of operation. With advanced protection schemes, DC fault management strategies, and standardization efforts (e.g., IEC and CIGRÉ technical references), DC systems are becoming more robust and easier to deploy in practical applications.



## 4.2. DC in Hybrid AC/DC Systems

### 4.2.1. HVDC

Advancements in power electronics and fully controllable semiconductors have significantly shaped the technical allowance and economic feasibility of HVDC systems. Consequently, HVDC has emerged as a leading option for high-capacity, long-distance power transmission and is now widely adopted across the globe, particularly in large countries (or across continents) where energy production is often remote from demand centers.

Moreover, enhanced interconnection through HVDC supports grid flexibility and diversity of energy sources, thereby improving supply reliability. DC links help addressing the intermittency challenges posed by renewable energy sources, strengthening energy security, promoting market competition within Europe, and aiding the shift toward a low-carbon electricity sector.

#### *4.2.1.1. Main Benefits of HVDC Compared to HVAC*

The primary benefits of HVDC over HVAC systems include:

- No need for reactive power compensation in transmission, allowing steady voltage at the receiving end over long distances and enabling full conductor utilization for active power. In contrast, long AC cable lines require devices like Static VAR Compensators (SVCs) or Static Compensators (STATCOMs) to maintain acceptable voltage levels.
- Greater power transfer capacity with comparable insulation and conductor size due to the absence of the skin effect in DC systems, allowing the use of thicker conductors.
- Reduced line losses for DC transmission; however, total losses must account for converter station losses.
- Ability to connect asynchronous AC systems, enabling both market exchanges and system support without the need for synchronized AC networks.
- Higher power density in HVDC overhead lines compared to AC equivalents, enabling reduced land and infrastructure requirements (e.g., smaller towers and narrower right-of-way).
- HVDC links offer precise and rapid control of power flows, enhancing system stability and reducing the need for operational interventions. With appropriate control coordination, HVDC can contribute to fewer remedial actions and improved damping of system oscillations, thereby improving AC grid utilization.





#### 4.2.1.2. Key Drawbacks of HVDC vs. HVAC

Despite these advantages, HVDC systems come with several drawbacks:

- HVAC transformers and circuit breakers are less expensive and less complex. Designing DC circuit breakers, especially for high-power VSC-HVDC systems, remains technically demanding.
- HVDC systems have higher upfront costs due to power electronics and converter infrastructure. However, for long distances, their cost advantage improves as HVDC systems typically use only two conductors in a bipolar setup, compared to three in AC systems. The method of current return (metallic vs. ground) impacts cost-effectiveness and system resilience.
- The dynamic behavior of HVDC systems is faster and different than AC networks, requiring dedicated operational and protection systems. This includes innovative hardware as well as software components. While solutions are in place for point-to-point HVDC line, new developments are needed for the management of multi-terminal HVDC networks.

#### 4.2.1.3. Common HVDC Applications

- **Connecting asynchronous or frequency-diverse AC systems:** HVDC enables coupling between systems with different operating frequencies or phase angles (e.g., the Uruguay-Brazil link or Eastern-Western US connection).
- **Submarine transmission:** HVDC cables are the preferred option beyond 40–150 km, depending on voltage, due to economic and technical efficiency.
- **Long-distance power transmission:** Overhead HVDC lines become more cost-effective at distances over 500–800 km. AC systems suffer from reactive power limitations over long distances.
- **Embedded HVDC links:** These operate in parallel with AC systems for power routing and regional control (e.g., the Western HVDC link in the UK).
- **Ancillary services:** HVDC systems can deliver services like frequency control, voltage support, and power balancing (e.g., the IFA interconnector between France and the UK).
- **UHVDC (Ultra High Voltage DC):** To meet demands for bulk power transfer (5–10 GW) in regions like China and South America, UHVDC technologies have been developed, such as the 6400 MW, 800 kV Xiangjiaba–Shanghai line. Key challenges include improving insulation, transformer design, and creating test facilities for UHVDC.





#### 4.2.1.4. HVDC Technology

A high voltage direct current (HVDC) system generally comprises a converter at the transmitting end that transforms alternating current (AC) into direct current (DC), and a converter at the receiving end that performs the reverse conversion from DC back to AC. The transmission link between these two converters can be made up of overhead lines, cables, or a combination of both.

Within each converter, power electronic valves—which function as high-capacity electronic switches—enable precise control over the direction and magnitude of power flow. HVDC systems are typically engineered so that either terminal can switch roles between rectifier and inverter, thereby allowing the direction of energy transfer to be reversed when required.

There are two predominant converter technologies employed in HVDC systems: the current source converter (CSC) and the voltage source converter (VSC). Each has distinct operational characteristics and technical requirements.

##### Current Source Converters

Current source converters have been in operational use since the 1950s and represent a mature technology. Most of the HVDC systems currently in service utilize the CSC approach. In these systems, the process of converting AC to DC inherently results in the generation of harmonic currents and the consumption of reactive power, both of which can degrade power quality. Consequently, it is necessary to install AC harmonic filters and reactive power compensation equipment to maintain appropriate power quality standards. Additionally, CSC systems are dependent on the AC system voltage for proper functioning, meaning disturbances in the AC grid can affect their operation.

The DC current in CSC-based systems flows in only one direction, and to reverse the direction of power transmission, the polarity of the DC voltage must be switched. This polarity reversal is executed via control systems within the converters, which requires a considerable amount of time, much larger than with VSCs. Harmonic filters on the AC side of the converter not only mitigate harmonic currents but also help in compensating for the reactive power consumed by the converter. These filters operate automatically, switching in or out based on real-time performance requirements.

On the DC side, reactors are used to smooth out current fluctuations and to limit peak currents in the event of faults. Additional DC filters may be needed to manage harmonic voltages, especially when overhead lines are part of the connection. CSC systems are particularly suited to high-voltage, high-capacity power transfers.



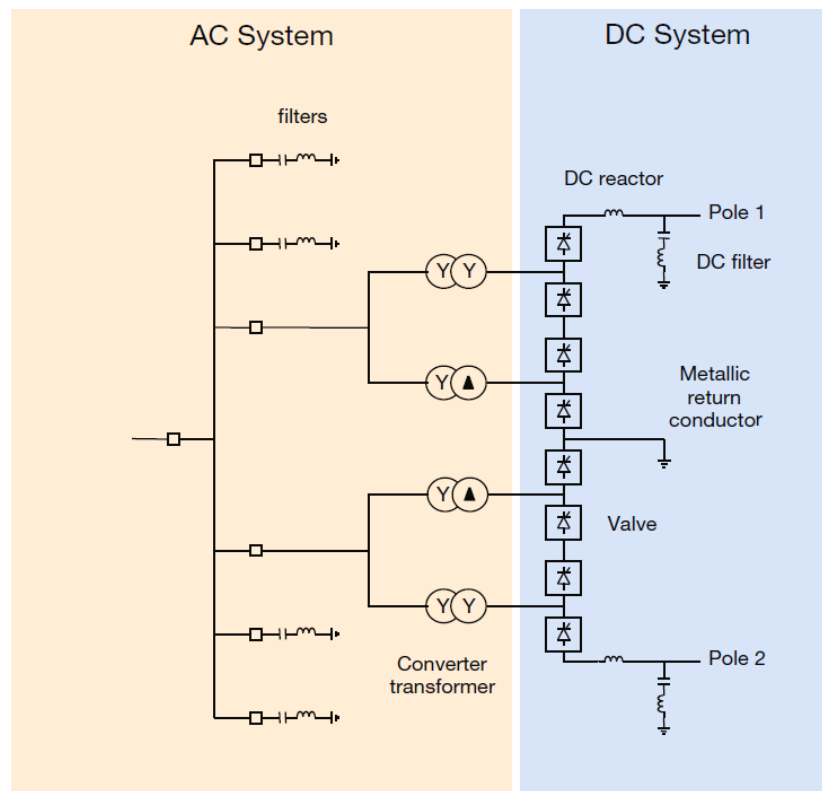


Figure 22. Example of CSC [1]

### Voltage Source Converters

VSCs have been used in HVDC transmission since 1997, becoming only recently the most installed technology. VSC systems use insulated gate bipolar transistor (IGBT) valves, which are self-commutating. The IGBT can be controlled both with regards to being turned on or off. In VSC technology, the DC current can flow in both directions. This key feature means that VSC systems are not reliant on the voltage conditions of the connected AC system, providing greater operational flexibility.

To date, VSC HVDC systems have operated at lower voltages and with smaller power ratings than their CSC counterparts.



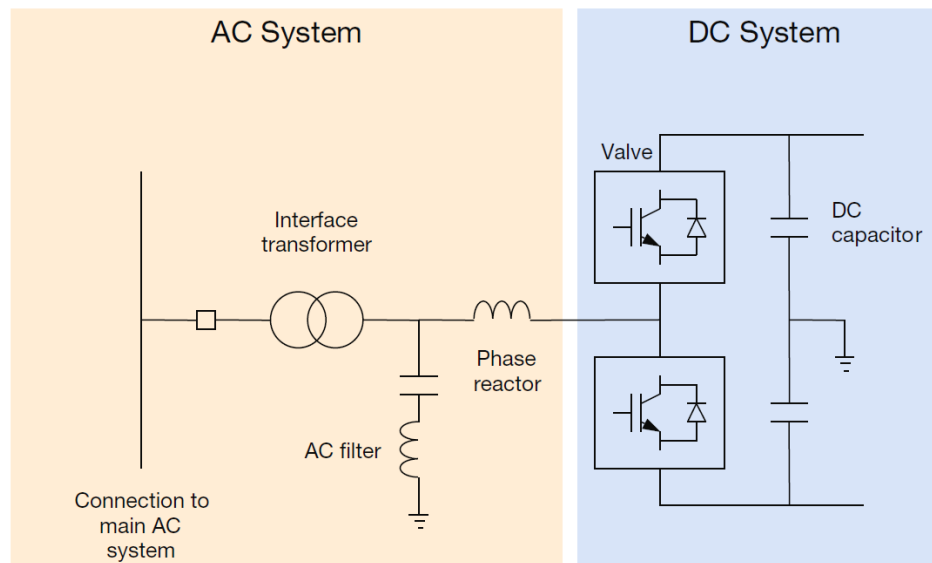


Figure 23. Example of VSC [26].

### CSC and VSC comparison

**Susceptibility to Commutation Failure:** In CSC systems, commutation failure can occur, especially when the AC voltage is disturbed. This issue does not affect VSC systems, as their self-commutating valves eliminate this dependency.

**Minimum DC Power Requirement:** CSC systems typically require a minimum power level—usually around 5% to 10% of the system's rated power—to function correctly. VSC systems, by contrast, can operate with no minimum power threshold, offering greater operational flexibility.

**Reactive Power Exchange with AC System:** CSC converters exchange significant reactive power with the AC grid (often around 50% of the transmitted active power), requiring dedicated reactive power compensation equipment. VSC systems are capable of independently controlling both active and reactive power, which enhances their flexibility and removes the necessity of external reactive compensation.

**Need for Reactive Power Compensation:** Due to their reactive power demands, CSC systems require dedicated reactive power compensation equipment. VSC systems do not need external reactive compensation, as they can handle it internally.

**Harmonic Filtering Requirements:** CSC systems generate harmonic currents and require switchable AC harmonic filters to manage power quality. In VSC systems, filtering needs are less intensive and filters do not need to be switchable.



#### 4.2.2. MVDC

Classical AC distribution grids are wildly oversized. To address the limitations of conventional AC distribution networks, DC technology utilizing modern power electronics offers cost-effective and socially preferable technical alternatives to AC-based systems. Converting existing AC lines to MVDC operation can significantly reduce costs by eliminating or postponing the need for constructing new AC lines. This is especially important in urban areas, where space constraints often make new line construction unfeasible.

Research indicates that DC cables can be laid within existing infrastructure, do not require phase transposition, and can transmit 1.5 to 2 times more power than a three-phase cable of the same conductor cross section.

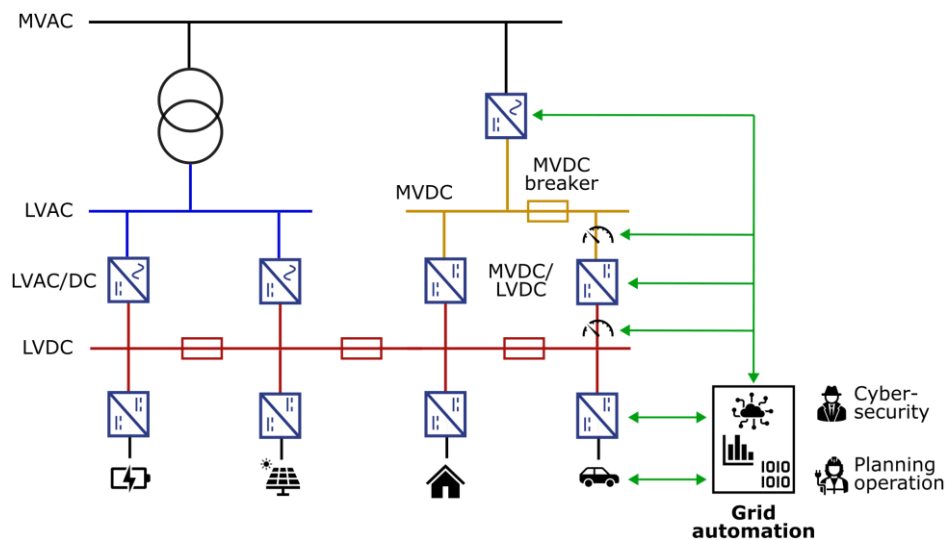


Figure 24. Conceptual representation of hybrid AC/DC distribution networks [27].

Moreover, as the switching frequency of DC-to-DC converters—commonly referred to as solid-state DC transformers—can be much higher than the AC grid frequency, the transformer size can be significantly minimized. Additionally, DC networks allow interconnection through DC converters that enable dynamic power flow control. Therefore, as illustrated in Figure 24, connecting substations via a DC link ensures uninterrupted energy exchange and precise control over power flow. This hybrid AC-DC system enhances both reliability and power quality when several substations are linked. Inverters on the AC side can supply VAR compensation (for power quality) and active damping (for stability) to the AC grid. Moreover, distribution transformers do not peak simultaneously due to shifting loads throughout the day. Thus, surplus capacity at one substation transformer can be redirected via the DC underlay to consumers served by another substation. Furthermore, bidirectional DC-to-DC converters can maintain a stable voltage output on the secondary



side, even with significant variation on the primary input side. As a result, voltage quality at the consumer end becomes largely independent of traditional grid planning.

This flexible power routing capability is especially beneficial for DSOs, as it allows efficient redistribution of energy across all voltage levels within their own networks. In turn, this often eliminates the need to rely on high-voltage transmission tariffs.

In today's AC distribution networks, the primary motivation for upgrading to DC technology is increasing load demand and the need for greater reliability. One approach involves retrofitting existing AC lines (both feeders and normally open tie-lines) for DC operation by installing AC-DC converters at each end. This method avoids the need for additional conductors, as DC allows higher power transfer density.

Alternatively, a new parallel DC link can be built, requiring AC-DC converters at both ends. Two converter station architectures are typically considered:

- a) a **common DC bus**, where each DC pole supplies  $NDC/2$  conductors ( $NDC$  being the total number of active DC conductors);
- b) **independently operated DC links**, each with its own AC-DC converter ( $NDC/2$  in total).

Operational strategies further differentiate between:

- **Parallel operation**, where AC and DC links run concurrently;
- **Alternative operation**, where reconfiguration via dedicated switches enables one link to serve as a backup—preferred for handling system contingencies.

Selection among reinforcement options is typically based on economic evaluation, considering factors such as payback period, operational losses, projected load growth, and capital investment.

#### *4.2.2.1. Comparison among DC and AC in MV Networks*

Beyond enabling a seamless DC power grid, the benefits of DC technology can also help address challenges in hybrid grid configurations. The expected advantages include:

- Immunity to phase and frequency variations;
- Higher achievable RMS voltage at the same peak electric field strength;
- Elimination of reactive power;
- Reduced losses or increased power transfer capability;
- Minimal leakage losses;
- No corona discharge losses for overhead lines;
- No steady-state induced sheath currents or voltages, and negligible capacitive leakage in cables.



DC technology offers several operational benefits for medium-voltage networks, which ultimately benefit end users. These include:

- Increased power transfer capability and improved power flow control within existing infrastructure;
- Greater precision in managing power flow within distribution circuits;
- Elimination of circuit overload risks;
- Regulation of AC voltage levels at both ends of the distribution line;
- Reactive power flow management at both ends of the circuit;
- Reduced losses across the distribution network due to improved voltage regulation;
- Fast voltage support during fault conditions;
- Isolation of fault levels between interconnected distribution systems;
- Faster and easier integration of renewable energy sources into the grid.

#### 4.2.3. Configuration of MVDC and HVDC Networks

Regarding the possible configurations of MVDC and HVDC systems, the following classification is proposed [28], [26]:

- a) **Point-to-point transmission**, connecting two AC/DC converters; within this category, two options are possible:
  - i. **Back-to-back**: in which two converters are connected directly in series or with a very short DC line; the goal is to control the power transfer among two asynchronous AC systems (having different frequencies or without fixed phase relationship).
  - ii. **Long distance**: using cables or overhead lines to interconnect two converters in different locations.
- b) **Radial network**, supplying loads and Distributed Generation (DG) from a single AC/DC converter;
- c) **Meshed network**, interlinking multiple AC/DC converters. In the MVDC case, the network interconnects also loads and DG.

Additionally, for MVDC networks, the following configuration is also possible:

- d) **Ring network**, distributing loads and DG along a point-to-point link.

The network configurations are illustrated in Figure 25.



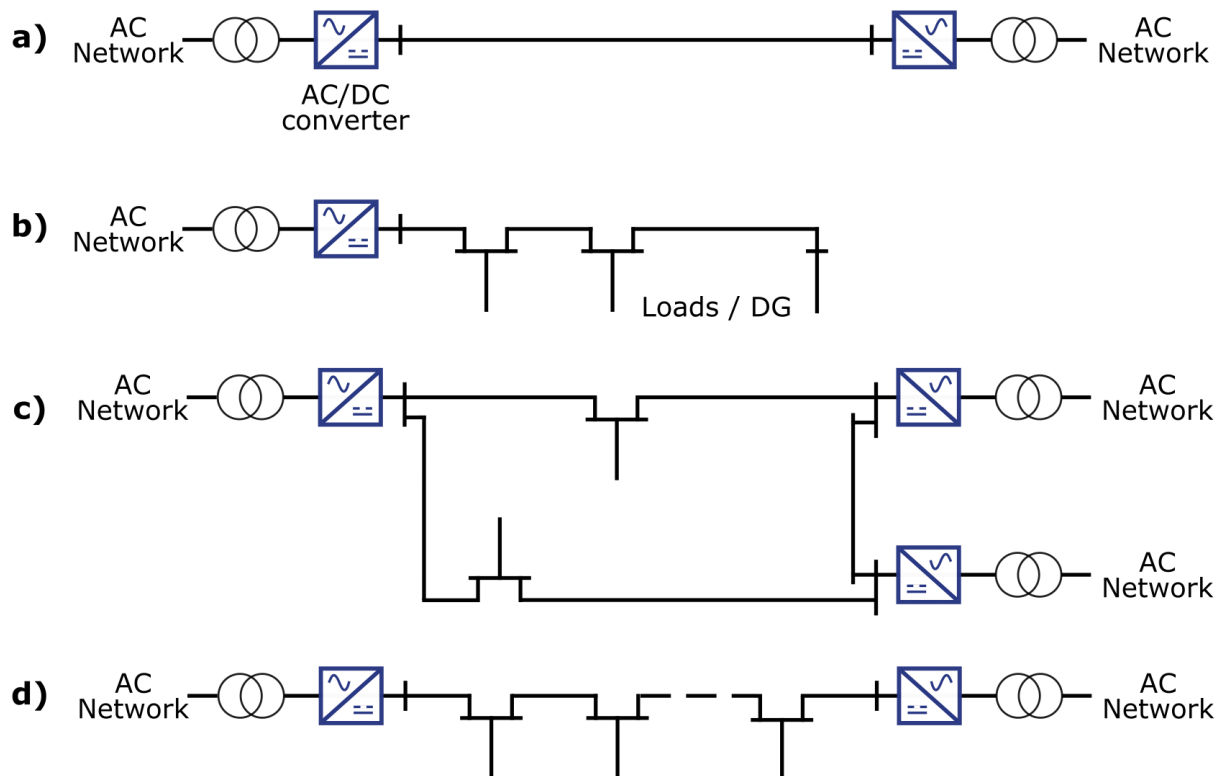


Figure 25. MVDC network configurations: (a) point-to-point, (b) radial, (c) meshed and (d) ring (only for MVDC) [27].

Furthermore, the literature outlines several line configuration options:

- a) **Asymmetric monopole:** one DC conductor operates at the full system voltage while the second is typically grounded.
- b) **Symmetric monopole:** both DC conductors operate at half the nominal voltage (e.g.,  $\pm 5$  kV); grounding can occur on the AC side (e.g., at the transformer's star point or through a star point reactor) or on the DC side (at the AC-DC converter), using either high or low impedance.
- c) **Bipolar:** implemented with multiple AC-DC converters (or a converter capable of bipolar operation); grounding options include rigid bipole, metallic return, or ground return.



## 4.3. Operation of Hybrid AC/DC Networks

### 4.3.1. Control of HVDC systems

Coordination of HVDC functionalities involves multiple operational processes and the participation of various parties (in most of the cases only TSOs; anyway, DSOs or other significant grid users may eventually be involved). The functionalities are executed with automated exchange of information, which can be executed in real-time, with longer cadence or event-driven. Such operational processes can be categorized in sequential control and continuous control [29], as described in the sections 724.3.1.1 and 4.3.1.2.

#### 4.3.1.1. Sequential Control

In a given HVDC system topology, various DC connection modes can exist. These modes define how individual units within the HVDC system are interconnected at their DC points-of-connection. The specific connection mode depends on the states of the switching devices across the grid.

Sequential control refers to the planned sequence of actions that transitions the HVDC system from one connection mode to another. These actions can be initiated automatically, manually by an operator, or through a combination of both. Connection mode changes triggered by protection actions—such as line disconnections—are not considered part of sequential control but are instead classified as protection responses.

For the purposes of sequential control, the states of units within an HVDC system—or a network of HVDC converter and switching stations connected on the DC side—may be directly managed by a DC grid controller, a national dispatch center, or by local control of switchgear at the switching station level.

In the context of sequential control, the following functions are addressed:

- **Facilitate operational simplification for planned reconfigurations:** While the full definition of all grid connection modes and their transitions must be established by the relevant TSO (in coordination with neighboring TSOs where applicable), the DC grid controller can manage macro-sequences for executing planned reconfiguration actions. These may include starting up or shutting down the DC network, connecting or disconnecting transmission lines or converters, and relocating the system earthing point.
- **Respond to unscheduled events, when needed:** While faults and other unexpected events are primarily handled by protection systems to ensure HVDC system security, sequential control can be used to support power system reliability afterward. Such actions can be part of the operational





simplification functionality or triggered automatically and locally when faster response is advantageous. Examples include:

- Recovery procedures following fault isolation to reconnect healthy parts of the fault separation zone, possibly via local auto-reclosing.
- Busbar reconfiguration after a busbar fault.

In any sequence, the actions consist of open and close commands sent to switching units. These commands are typically issued to the switching station automation system, which relays them to the appropriate switching units.

Additionally, switching stations may implement interlocks between switching units to prevent incorrect operations—such as closing onto an earthed or out-of-service unit. The DC grid controller will issue commands to switching units only when all interlock conditions are met.

#### 4.3.1.2. Continuous Control

HVDC systems must deliver scheduled power while maintaining their own security and reliability to ensure uninterrupted operation. It is essential to avoid power flows and DC voltage levels that exceed the physical limits of system components. Any disturbance can upset the power balance, leading to fluctuations in DC voltage. In such cases, the AC/DC converters must respond swiftly and in coordination to restore energy balance and prevent system limit violations.

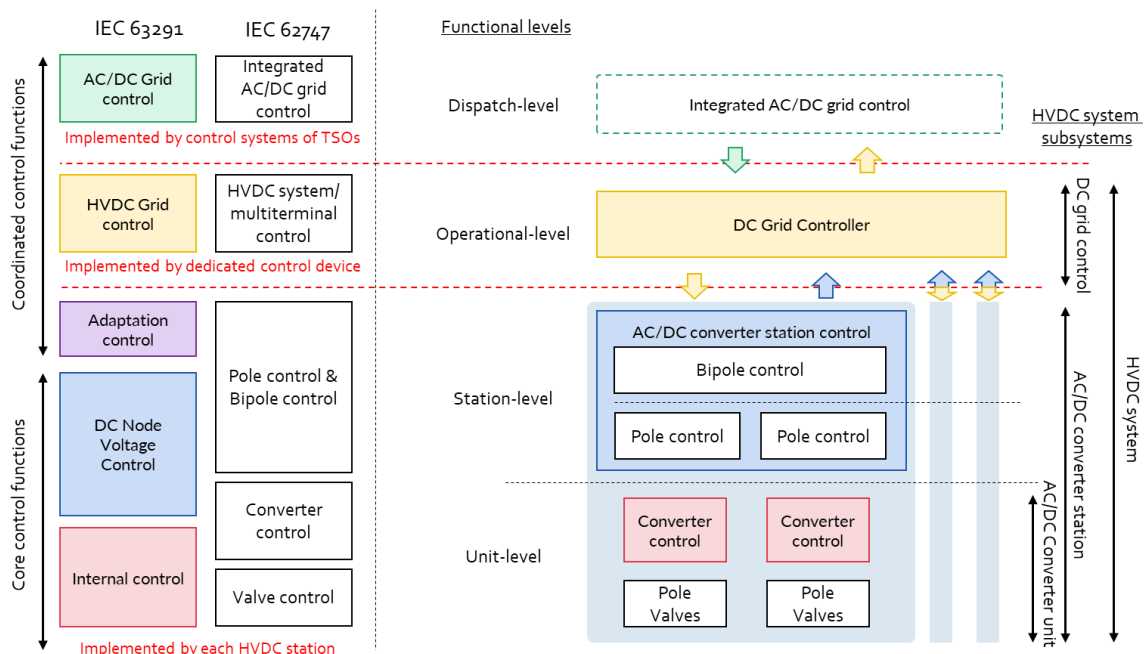


Figure 26. General continuous control architecture for HVDC systems [29].



To support both scheduled power delivery and dependable, continuous operation, HVDC systems are organized under a hierarchical control architecture. This structure assigns specific roles and responsibilities to each control layer and ensures the secure exchange and propagation of critical information across all levels. The architecture, shown in Figure 26, is divided into four functional levels—**Dispatch, Operational, Station, and Unit**—each with clearly defined roles and responsibilities.

At the **Dispatch level**, control centers or national dispatch facilities manage high-level power flow references and voltage setpoints across the HVDC network. These are typically slower-acting controls based on broader grid requirements and market operations.

The **Operational level** handles real-time operational decisions and serves as an intermediary between the dispatch level and field-level controllers. It is responsible for translating dispatch commands into executable setpoints for individual stations and for ensuring coordination among stations. This layer also considers dynamic boundary conditions from the surrounding AC networks and optimizes the internal behavior of the HVDC system accordingly.

The **Station level** control focuses on the management of local subsystems, such as converter stations or switching stations. It ensures proper execution of commands received from the operational level and manages local constraints, such as the current handling capability of converters or the operational readiness of equipment.

Finally, the **Unit level** is responsible for the direct control of equipment like AC/DC converters and DC switchgear. These units execute detailed control algorithms, such as primary DC voltage control or power modulation, and report back their status to the higher control layers.

The architecture ensures **secure communication and coordinated action** across all levels, supporting both steady-state and dynamic responses. It accommodates **multi-vendor, multi-terminal HVDC grids**, ensuring interoperability by prescribing only functional requirements—not technology-specific implementations. This layered approach enhances system stability, enables scalability, and facilitates the integration of renewable energy sources by ensuring that all parts of the HVDC system work harmoniously within defined performance limits.

#### 4.3.2. Control of MVDC Systems

In current applications, MVDC links function as DC couplers or links within meshed medium-voltage AC grids, enabling controlled power flow. These systems operate similarly to HVDC systems used in transmission networks, but on a smaller scale and over shorter distances.



From an operational and protection standpoint, they typically behave as point-to-point transmission links.

The MVDC point of interconnection can be located either within the distribution grid or directly connected to the transmission grid via a standard AC transformer. This results in a distributed MVDC architecture involving multiple voltage levels.

Traditional DC transmission systems, such as HVDC and MVDC links or couplers, regulate power flow between grids or within a meshed grid section. In these configurations, the DC link acts as a current source for each grid, allowing bidirectional power flow. One of the converters maintains the DC voltage, thereby establishing a DC grid.

In emerging MVDC networks, DERs and loads typically operate under constant power control, injecting or drawing current from the grid. As a result, their interface converters must be grid-forming, acting as voltage sources. In this setup, both ends of the MVDC link are grid-forming—one establishes the DC grid, while the other forms the AC grid for DERs and loads.

#### *4.3.2.1. Multi-terminal MVDC Grid Operation and Control*

The control of a multi-terminal MVDC grid can follow the conventional multi-layered control architecture similar to that used in HVDC systems. However, due to the unique characteristics of distribution networks - notably the higher variability of loads and the integration of numerous DERs - greater emphasis must be placed on scalability and interoperability.

This multi-layered control structure typically consists of three hierarchical levels [26]:

- **System Control:** this top-level layer coordinates all converters in the grid by assigning voltage or power references based on overall operational goals.
- **Converter Control:** operating in real time, this layer minimizes the difference between the system-provided reference values and actual measurements. It ensures that power and voltage setpoints are accurately tracked.
- **Valve Control:** at the lowest level, valve control generates modulation pulses to appropriately trigger the power electronic valves.

The converter control layer receives voltage and power references from the system control layer and adjusts its output to follow these targets. Using algorithms such as Proportional-Integral (PI) control, it continuously reduces deviations between reference values and actual measurements. These control strategies are often represented graphically using power-voltage characteristic curves.

System-level control manages the coordination of converters across the MVDC grid by assigning voltage or power references based on predefined operational objectives. This



control layer focuses on optimizing real-time DC voltage and active power flow from a system-wide perspective. Several well-established control strategies are currently used for this purpose, including master-slave control, voltage margin control, and voltage droop control. To ensure seamless operation within the broader power system, MVDC control functions must be integrated into both station-level control systems and centralized grid control centers, similarly to other grid-connected resources.

#### 4.3.3. Protection for DC Systems

In comparison to AC grids, DC grids introduce unique considerations for protection settings, including:

- **Control Mode Coordination:** Subordinate power converters must mirror the operational mode of the main (top-level) converter. For instance, if the top-level converter switches between power-feeding and grid-forming modes, downstream converters must synchronize their mode transitions accordingly.
- **Galvanic Isolation Requirements:** Unlike AC systems—where transformers provide galvanic isolation—DC grids require alternative solutions. Isolation must be achieved via suitable power converter designs.
- **Converters as Switchgear:** In some grid topologies (e.g., at busbars or in linear/meshed configurations), power converters can perform switching functions, replacing circuit breakers under certain conditions. However, voltage separation must still be handled via isolating switches and, for selective feeder protection, DC circuit breakers remain necessary.

##### 4.3.3.1. HVDC System Protection

As part of DC grid protection coordination, Fault Separation Zones (FSZs) must be defined to ensure that all ordinary contingencies can be effectively isolated, while maintaining compliance with AC system boundaries. Specifically, FSZs must account for the maximum allowable loss of infeed from adjacent AC grids and support the continued stable operation of the DC grid following fault separation.

At the boundaries of each FSZ, switching units must be equipped with Fault Separation Devices (FSDs) capable of isolating all ordinary faults within a defined maximum fault neutralization time.

Converters located outside the affected FSZ are expected to remain connected to the DC grid and continue operating following fault isolation. To support this, the DC Fault-Ride-Through (DC-FRT) profile at the converter's Point of Connection (PoC) must ensure the following:



- Continued converter connection during the fault separation process
- Reliable operation of the converter after the fault has been cleared
- Safe disconnection in the event of a protection system failure

This approach ensures both fault containment and system stability in complex, multi-terminal DC grid configurations.

#### 4.3.3.2. MVDC System Protection

Currently, the overall maturity level of protection strategies for MVDC systems, encompassing the FLISR module, warrants further developments. The underdevelopment is due, in comparison with HVDC, to both technical limitations and cost reasons. Existing research, identifies three primary approaches for DC fault isolation in MVDC distribution networks:

- **AC Circuit Breaker (ACCB) Method:** This approach uses AC-side circuit breakers of converters to clear DC faults. While simple and cost-effective, it causes the shutdown of the entire DC network, making it unsuitable where selective protection is required.
- **Converters with Fault-Blocking Capability:** Certain converter topologies inherently support fault isolation. However, these solutions are more complex and expensive, involving higher capital costs and increased power losses.
- **DC Circuit Breakers (DCCBs):** These enable fast and localized fault isolation, making them suitable for DC grid applications. Nevertheless, their cost and reliability remain challenges that must be addressed before widespread deployment.

## 4.4. Regulatory and Standardization Overview

The regulatory and standardization situation among DC technology in HV and MV is profoundly different. Due to the earlier application in the higher voltage levels, the status of regulations and standards for HVDC is much more mature, whereas several standardization activities for MVDC are ongoing.

### 4.4.1. HVDC Regulations and Standards

The **Commission Regulation (EU) 2016/1447 “establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules”** is currently in force as the reference regulation for HVDC [30]. It is a legally binding European regulation that sets the technical requirements for the connection of HVDC systems and DC-connected power park modules



(such as offshore wind farms) to the AC transmission networks in the European Union. Enacted under the EU's broader framework for grid harmonization, it aims to ensure secure, reliable, and efficient system operation across borders by mandating standardized connection requirements. The regulation applies to all new HVDC connections and DC-connected generation units that connect to the public grid at or above 110 kV. It outlines the minimum technical capabilities and performance criteria that such systems must fulfill. These include robust voltage and frequency control capabilities, fast fault-ride-through performance to support grid stability during disturbances, and black-start capabilities to aid system restoration after blackouts. Additionally, the code requires coordination between the HVDC converter's control systems and the TSO, with detailed provisions for testing, compliance verification, and real-time operational coordination. This regulation plays a critical role in facilitating the deployment of long-distance and cross-border HVDC links, particularly for the integration of large-scale renewable energy sources.

Regarding the standardization documents, the key ones adopted across Europe are hereafter described.

- **IEC 61803 – Determination of Losses in HVDC Converter Stations** [31]. IEC 61803 is an international standard that defines consistent methods for evaluating losses in HVDC converter stations, both for line-commutated converters (LCC) and VSC. The focus of this standard is on quantifying energy losses that occur within the converter station, including those from power electronic components (such as thyristors or IGBTs), cooling systems, control equipment, transformers, filters, and auxiliary systems. Loss determination is crucial for both the economic and technical assessment of HVDC projects. Accurate loss data informs system efficiency evaluations, influences the financial models and payback periods of HVDC investments, and contributes to system-level planning (e.g., thermal modeling and system balancing). The standard ensures that all parties — utilities, manufacturers, and regulators — use a harmonized framework for calculating and reporting losses, thereby facilitating transparent comparison between competing technologies and project designs.
- **IEC 61975 – Guidelines for the Planning of HVDC Transmission Systems** [32]. IEC 61975 provides a comprehensive set of guidelines to assist in the planning and design of HVDC transmission systems. This standard serves as a foundational resource for engineers, planners, and decision-makers involved in the early stages of HVDC project development. It covers both point-to-point and multi-terminal HVDC systems, offering guidance on technical considerations, system integration, operational flexibility, environmental impact, and economic feasibility. The standard emphasizes a systematic planning approach, taking into account system studies (e.g., power flow, stability, and electromagnetic compatibility), site selection, right-of-





way planning, converter station design, and control strategies. It discusses trade-offs between different HVDC technologies (LCC vs VSC), grounding schemes, cable vs overhead line selection, and the integration of HVDC into existing AC networks. While it is not prescriptive, IEC 61975 functions as a valuable best-practices document, helping stakeholders design HVDC systems that are reliable, scalable, and compatible with long-term grid development goals.

- **IEC 62747 – Terminology for HVDC Transmission and Grids** [33]. IEC 62747 serves a foundational role in standardization by providing a harmonized vocabulary for HVDC transmission systems and HVDC grids. As the HVDC sector has evolved, multiple stakeholders — including manufacturers, TSOs, regulatory bodies, and academia — have developed varying terminologies for similar concepts. This standard resolves these inconsistencies by defining key terms related to HVDC components (e.g., converters, valves, DC buses), control systems, operation modes, and system configurations. By establishing common language, IEC 62747 supports effective communication across the HVDC value chain and ensures that technical documents, standards, contracts, and regulatory frameworks use consistent and unambiguous terminology. This is especially important for complex, multi-party HVDC projects such as cross-border interconnectors or offshore transmission hubs, where misunderstandings in terminology can lead to costly design errors or delays.
- **IEC 62895 – Guidelines for Operation and Maintenance of HVDC Transmission Systems** [34]. IEC 62895 provides a detailed guide on the operation and maintenance (O&M) of HVDC converter stations and associated transmission infrastructure. As HVDC systems are highly specialized and capital-intensive, effective O&M strategies are essential to maximize system availability, prolong equipment lifespan, and ensure safety. The standard covers operational best practices, including control room procedures, switching operations, and emergency handling. It also outlines maintenance strategies such as condition-based monitoring, preventive maintenance schedules, and spare parts management. Specific guidance is offered for key components such as converter valves, cooling systems, transformers, and control equipment. IEC 62895 addresses the organizational aspects of O&M, recommending appropriate documentation, staff training, and communication protocols. It also considers modern approaches like remote diagnostics and digital asset management tools. The document is useful for asset owners, service providers, and maintenance engineers, and it provides a benchmark for regulatory compliance and performance evaluation in HVDC projects.
- **IEC 63143 (Under Development) – Functional Requirements for Multi-terminal HVDC Systems** [35]. IEC 63143 is a draft standard currently under development, aiming to define the functional and performance requirements for multi-terminal HVDC systems. While most existing HVDC installations are point-to-point, the



industry is moving toward more complex configurations where multiple converter stations are interconnected in a meshed or radial topology — essentially forming HVDC "grids." This emerging standard is set to provide guidance on how such systems should be functionally specified, focusing on areas such as interoperability between different vendors, voltage and frequency control, fault detection and isolation, system protection strategies, and dynamic system performance. The document aims to address the coordination challenges inherent in multi-terminal DC systems, where real-time decisions (e.g., power flow control or converter prioritization) must be made across multiple terminals with potentially conflicting objectives. IEC 63143 will be crucial in enabling the future deployment of interconnected HVDC grids, such as those envisioned in the North Sea Wind Power Hub or similar pan-European transmission initiatives.

- **IEC 60076-57-129 – Power Transformers for HVDC Applications** [36]. IEC 60076-57-129 is part of the broader IEC 60076 series on power transformers but is specifically tailored to the requirements of transformers used in HVDC converter stations. These transformers, often referred to as converter transformers, face unique operational stresses due to the presence of DC biasing, harmonic content, and rapid voltage changes associated with converter operation. This standard provides requirements for the design, testing, and performance of HVDC power transformers, addressing insulation coordination, dielectric strength, temperature rise limits, electromagnetic compatibility, and mechanical robustness. It also includes test protocols that simulate operating conditions such as polarity reversal or high-voltage switching transients. The aim is to ensure reliable and safe transformer operation under the demanding electrical and thermal conditions present in HVDC systems. IEC 60076-57-129 is essential for transformer manufacturers and HVDC system integrators, as it sets performance benchmarks and ensures compatibility with the overall converter station design.

Beside these documents, it is worth to mention that each EU member state has its national grid code, aligned with EU network codes and referencing IEC/CENELEC standards.

#### 4.4.2. MVDC Regulations and Standards

Despite the growing interest and early-stage deployments, the regulatory and standardization landscape for MVDC in Europe remains fragmented and underdeveloped, especially in comparison to the well-established framework surrounding HVDC systems described above.

One of the fundamental challenges in regulating MVDC systems stems from their diverse application domains and relatively low level of large-scale deployment. Unlike HVDC, MVDC tends to operate within local or specialized contexts—such as the DC distribution networks





for offshore wind farms, subsea infrastructure, and islanded energy systems. As such, MVDC projects are currently governed more by project-specific technical specifications and engineering best practices than by harmonized European or international regulatory codes.

At the European Union level, no dedicated MVDC regulation exists akin to the Commission Regulation (EU) 2016/1447—which governs HVDC grid connections. MVDC systems do not fall directly under the scope of existing Network Codes, primarily because these codes apply to connections at or above 110 kV, while MVDC systems typically operate in the 1.5 kV to 60 kV range, occasionally extending to around 150 kV depending on classification. As a result, MVDC applications fall into a regulatory grey area, subject only to more general electrical safety standards and national codes that are primarily tailored to AC systems. The absence of standards is indicated by DSOs as one of the main barriers to the current, large-scale deployment of MVDC systems; in fact, the current situation makes almost impossible the purchase of off-the-shelf MVDC hardware and software.

From a standardization perspective, however, IEC and CIGRÉ have recognized the growing relevance of MVDC and have initiated several important activities. Within the IEC, Technical Committees TC 8 (System Aspects of Electrical Energy Supply) and TC 22 (Power Electronic Systems and Equipment) are actively involved in defining requirements for DC-based systems, including medium-voltage levels. Of particular importance is IEC TC 64, which addresses electrical installations and safety rules, and has begun to consider DC-specific adaptations of IEC 60364, the foundational standard for low-voltage installations.

Additionally, IEC SC 77A, which deals with electromagnetic compatibility (EMC) of low- and medium-voltage installations, is contributing to defining EMC limits and testing procedures for DC networks that include power electronic converters—an essential component in MVDC systems.

Efforts are also underway to develop dedicated standards that focus on DC protection, control, and insulation coordination, areas where existing AC standards do not fully translate. One such initiative is the development of IEC 63295 (in draft stage), which seeks to provide guidance for DC protection and fault management in medium-voltage systems. Similarly, IEC 63152 explores reliability models for smart energy systems that include DC operation. These standards, while not exclusively dedicated to MVDC, reflect growing awareness within the IEC community of the need to support DC at the medium voltage level.

Parallel to IEC's activities, CIGRÉ, the International Council on Large Electric Systems, has also initiated a number of technical working groups (WGs) under Study Committee B4 (DC Systems and Power Electronics) that are directly relevant to MVDC. Notably:

- **CIGRÉ B4.83** focuses on functional requirements for VSC HVDC systems, many of which are applicable to MVDC designs using similar converter topologies.



- **CIGRÉ B4.84** addresses control and protection strategies for future DC grids, including both HVDC and MVDC scales.
- **CIGRÉ B4.91** investigates the feasibility of MVDC applications in distribution networks, considering interoperability, equipment design, and fault-handling capabilities.

These working groups have produced a series of technical brochures and benchmark studies that have become informal references for developers and researchers working in the MVDC domain. Although not legally binding, they provide valuable guidance and represent the most technically mature material available on MVDC at this stage.

## 4.5. SCADA for AC/DC Networks

As power grids evolve toward hybrid architectures combining AC and DC segments, SCADA systems are facing a paradigm shift. Traditional SCADA setups are tailored to AC networks with relatively coarse data rates, simple fault dynamics, and legacy protocols. Hybrid grids introduce several new requirements and challenges.

- **Data Granularity and Dynamics.** In AC systems, SCADA primarily handles data rates on the order of seconds or minutes and relies on phasor-based measurements. In contrast, DC sub-networks, especially those involving power electronic converters, operate on much faster timescales and lack natural phase/frequency metrics. Hence SCADA must capture higher-frequency data and account for different time constants across AC and DC layers [13]. This implies the need to augment SCADA with faster data collection (e.g., sub-second reporting), custom RTUs designed for DC bus voltage and current sensing, and the integration of high-speed measurement units.
- **Communication Infrastructure & Protocols.** Hybrid SCADA architectures require robust, low-latency, high-bandwidth communication across multiple layers—from RTUs on converters to centralized control stations. Established protocols (e.g., IEC 61850, IEEE C37.118, IEEE 1646) are mature for AC networks, but DC segments necessitate extensions to handle new metadata such as DC voltage, polarity, and converter states.
- **Monitoring and Control Algorithms.** Traditional monitoring and control algorithms (for example, state estimators as well as tools that are part of EMS/DMS) assume AC-specific phasor models. Hybrid environments require estimators capable of handling mixed variable types—phasor-based AC states and scalar DC parameters.
- **Protection Integration.** DC networks lack the natural zero-crossings that AC relies on for fault clearing, leading to severe harmonics and fast-transient dynamics.



SCADA must therefore integrate protection schemes specific to DC, including fast DC breakers and real-time fault detection [37].



## 5. Grid Operators Viewpoint

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To further analyze the solutions currently used for SCADA also in conjunction with AC/DC technologies, along with existing barriers and weaknesses, it was deemed essential to directly investigate the viewpoints and implementations of system operators.

For this purpose, firstly, bilateral **interviews** with different European Transmission and Distribution System Operators were conducted to obtain an overall assessment of the SCADA systems they are currently using.

Once the interviews were completed, the responses were processed through a **SWOT Analysis**. A SWOT analysis is a strategic planning tool used to identify and analyze the Strengths, Weaknesses, Opportunities, and Threats related to a project or business venture. In this context, the strengths refer to the advantageous features of the current SCADA systems, such as established functionalities and robust data handling. Weaknesses are the inherent limitations or areas where the tools fall short, such as fragmented and outdated architectures. Opportunities are external factors that could be leveraged to improve the tools, like unified system architectures with AI integration. Threats are external challenges that could hinder the effectiveness of the tools, such as cybersecurity risks and regulatory challenges.

To further substantiate the findings and ensure a broader perspective, a **survey** was designed and distributed to a larger group of participants beyond the InterSCADA project consortium. The survey targets Transmission System Operators (TSOs) and Distribution System Operators (DSOs) to gather insights on current SCADA/EMS/DMS/ADMS challenges and requirements for managing evolving grid conditions.

The open-ended nature of the interview questions combined with the more closed-ended nature of the survey has allowed to obtain a more accurate picture of the actual systems. The questions covered various aspects of the current tools, including user satisfaction, perceived effectiveness, and areas needing improvement. This information has been processed and included in this document.



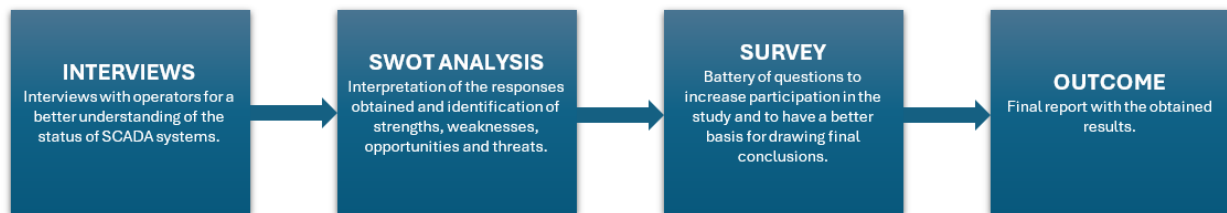


Figure 27. Methodology for the analysis and process of grid operators' viewpoints.

## 5.1. Interviews

Individual sessions were organized with five system operators (four TSOs and one DSO) part of the InterSCADA project consortium and its External Advisory Board (EAB): IPTO, REE, ASM Terni, RTE and Litgrid. Through close collaboration with system operators, it was possible to discuss the following topics related to SCADA systems used in their respective networks:

- Level of automation of operational functions.
- Interconnection of the different SCADA components.
- Interoperability and communication protocols: impact on efficiency and reliability as well as identified challenges.
- Limitations of the SCADA in place.
- Adaptation to the modernization of grid operations and role of DERs.
- New technologies and solutions having impact on SCADA systems.
- Data management, including scalability
- Human error: minimize risk and operators training.
- Real-time measurement for monitoring and control operations, including the role of PMUs.
- Integration, regulation and impact of AC/DC systems.
- Cybersecurity.

The interview responses provided valuable and insightful perspectives that significantly deepened the understanding of the system operators' experiences with the existing technologies. Participants shared detailed accounts of their interactions, highlighting both the strengths and the pain points they encountered, not only related to the topics mentioned above, but also their general experience.

With the aim of processing and categorizing the participants' responses as well as presenting them in an organized manner, it has been considered that the best way to show



them is through the SWOT analysis outlined in the following section. The questions presented during the interview can be found in the Appendix A.

## 5.2. SWOT Analysis

When evaluating a possible transition to a new version of any type of system, a SWOT analysis allows us to identify the strengths of the system currently in use and to address the weaknesses it shows according to its users. On the other hand, the new version to be implemented must be aware of the opportunities that this development presents and minimize the threats that this change represents to reduce risks.

Therefore, instead of evaluating each of the topics covered in the interview separately, it was decided to group them according to what they represented in a SWOT analysis. First, key points were identified, which are shown in Table 4, and each of these points is expanded below for further description.



Table 4. SWOT Analysis for the grid operators' viewpoints.

<p style="text-align: center;"><b><u>STRENGTHS</u></b></p> <ul style="list-style-type: none"> <li>• Interoperability Potential</li> <li>• Established Functionalities</li> <li>• Comprehensive Monitoring Capabilities</li> <li>• Automation in Monitoring &amp; Control</li> <li>• Existing Open-Source Efforts</li> <li>• In-House Development Capabilities</li> <li>• Robust Data Handling</li> <li>• Operator-Centric HMI Design</li> <li>• Established Training Practices</li> <li>• Integration with DER Management</li> <li>• HVDC Interoperability Advancements</li> <li>• Deployment of PMUs</li> </ul>	<p style="text-align: center;"><b><u>WEAKNESSES</u></b></p> <ul style="list-style-type: none"> <li>• Legacy SCADA System Limitations</li> <li>• Fragmented Architectures</li> <li>• Vendor Lock-in</li> <li>• Scalability Challenges</li> <li>• High Costs for Small DSOs</li> <li>• Limited Standardization Across Systems</li> <li>• Large time to develop new tools</li> <li>• Data Exchange Limitations</li> <li>• Outdated Systems and Protocols</li> <li>• Limited Data Exchange Speed</li> <li>• Limited Integration of DER Visibility Data</li> <li>• Fragmented DER Interconnection and Visibility</li> <li>• Slow OPF Computation</li> <li>• Limited PMU Deployment</li> <li>• Fragmented Training Simulation Systems for Operators</li> <li>• Regulatory Adaptation Challenges</li> <li>• Missing standards for hybrid AC-DC systems</li> </ul>
<p style="text-align: center;"><b><u>OPPORTUNITIES</u></b></p> <ul style="list-style-type: none"> <li>• Enhanced Open-Source Development</li> <li>• Unified System Architecture</li> <li>• Advanced Automation &amp; AI Integration</li> <li>• Improved Interoperability Standards</li> <li>• Modernization for DER Integration</li> <li>• Interoperability Improvements for DER and HVDC</li> <li>• Enhanced DSO-TSO Data Sharing</li> <li>• Open Standards Adoption</li> <li>• Cloud and Edge Computing Solutions</li> <li>• Cybersecurity-Enhanced SCADA Architectures</li> <li>• Predictive Maintenance with AI</li> <li>• Expansion of PMU Utilization</li> <li>• Enhanced Data Management Solutions</li> <li>• Growing Role of DC Systems</li> <li>• Advanced Training Simulators for Future Control Centers</li> <li>• Incremental System Upgrades</li> </ul>	<p style="text-align: center;"><b><u>THREATS</u></b></p> <ul style="list-style-type: none"> <li>• Cybersecurity Risks with Increased Connectivity</li> <li>• Regulatory and Compliance Challenges</li> <li>• Complexity of Large-Scale System Upgrades</li> <li>• Growing Data Management Demands</li> <li>• Resistance to Change</li> <li>• Operator Adaptability to AI and Automation</li> <li>• Data Overload and Latency Challenges</li> <li>• Uncertainty in AI Reliability for Critical Operations</li> <li>• Regulatory and Standardization Barriers</li> <li>• Manual Intervention Requirements</li> <li>• Data Storage and Scalability Constraints</li> </ul>



### 5.2.1. Strengths

- **Interoperability Potential:** Current SCADA systems in some TSOs integrate various protocols (e.g., OPC-UA, CIM/CGMES) and may support modular architectures, allowing communication with EMS and other control systems. Most SCADA systems incorporate specific protocols (e.g., IEC 61850, IEC 101/104, OPC-UA) to facilitate communication across different systems and devices, ensuring data exchange with market platforms and external control systems.
- **Established Functionalities:** Standard SCADA functionalities – such as state estimation, security analysis, and remote monitoring/control - are well established in conventional AC systems. For HVDC infrastructure, these capabilities are currently being developed and implemented in the first deployments. Some control features, including fast frequency response and voltage deviation detection with corrective actions, are implemented in initial HVDC applications, laying the groundwork for more robust hybrid system integration.
- **Comprehensive Monitoring Capabilities:** SCADA already provide extensive real-time monitoring for large-scale generation, including wind, solar, and conventional power plants, with integration into transmission and distribution networks.
- **Automation in Monitoring & Control:** While decision-making remains manual, automation for topology switching and alarm processing is increasingly integrated.
- **Existing Open-Source Efforts:** Some functionalities (e.g., power flow engines) have been developed in-house by the system operators (e.g., TSOs and DSOs) and released as open-source solutions, laying a foundation for future collaboration.
- **In-House Development Capabilities:** Some TSOs and DSOs develop internal tools (e.g., optimal power flow, voltage control) to enhance their systems functionalities without relying entirely on vendors. This is mostly applicable for large TSOs, which own stronger in-house capabilities.
- **Robust Data Handling:** Most SCADA systems currently manage large datasets effectively through historical recording systems in the SCADA systems and real-time synchronization with databases.
- **Operator-Centric HMI Design:** Human-Machine Interfaces (HMI) incorporate logic control, warning flags, and large display walls to minimize human error and enhance situational awareness.
- **Established Training Practices:** Dispatch Training Simulators (DTS) are widely used for operator training, with some TSOs conducting drills in collaboration with each other.
- **Integration with DER Management:** Some SCADA systems are evolving to incorporate DER management functionalities, allowing better coordination of DERs





with real-time grid operations. System operators are acquiring more and more experience in monitoring and control large generations (e.g., > 5MW or > 1 MW).

- **HVDC Interoperability Advancements:** Automated HVDC control systems are improving cross-border energy exchange and grid resilience by responding dynamically to overloads and voltage deviations (controlling the transmitted active and reactive power). For example, specific tools can curtail the power transfer on an HVDC line to a predefined value, in case of tripping conditions; or, in case the system changes from interconnected (synchronized) to isolated, the frequency control settings automatically change to predefined ones. Furthermore, VSC for HVDC systems are particularly well-suited for grid-forming applications due to their inherent ability to independently control both voltage and frequency. This could make them a good solution for supporting weak or islanded grids, where traditional synchronous generation is limited or a
- **Deployment of PMUs:** PMUs are being installed in the network, with several system operators initiating programs to expand their use. Although the current number of installed PMUs is not yet significant, these devices offer high-precision, real-time measurements that can greatly enhance monitoring and control capabilities. As deployment progresses, PMUs are poised to play an increasingly pivotal role in enabling intelligent, real-time grid management—particularly within the evolving landscape of hybrid AC/DC systems.

### 5.2.2. Weaknesses

- **Legacy SCADA System Limitations:** Many SCADA systems are proprietary and monolithic, limiting flexibility and slowing the integration of new functionalities such as PMUs and AI-driven analytics as well as visibility, monitoring and control of DERs.
- **Fragmented Architectures:** In some cases, TSOs operate multiple SCADA systems for different tasks (e.g., main grid, DSO data, DC links), leading to complexity and integration challenges.
- **Vendor Lock-in:** Systems relying on a single vendor face slow and costly implementation of changes, limiting flexibility in adopting new technologies. Transitioning from older SCADA versions takes years, restricting innovation and adaptability.
- **Scalability Challenges:** Large infrastructure networks, such as those managed by large TSOs/DSOs, struggle with increasing the volume of data handled, impacting system performance and computational efficiency.
- **High Costs for Small DSOs:** Smaller DSOs might face financial constraints in upgrading or adapting SCADA systems due to high costs of customization and maintenance.



- **Limited Standardization Across Systems:** Differences in vendor solutions (e.g., vendor vs. in-house developments) and reliance on proprietary technologies hinder seamless interoperability.
- **Interoperability Challenges in TSO-DSO Data Exchange:** The integration of DERs at the distribution level introduces significant challenges in data exchange between TSOs and DSOs. The use of diverse communication protocols and inconsistent interface standards complicates real-time coordination. Establishing seamless interoperability will require substantial effort in harmonizing data models, ensuring cybersecurity, and developing standardized interfaces to support reliable and secure information flow across grid levels.
- **Limited Data Exchange Speed:** Frequency of data exchange between TSO and DSO remains slow (e.g., 1-minute intervals compared to 10 s for transmission), impacting real-time decision-making.
- **Outdated Systems and Protocols:** Some organizations continue to rely on outdated SCADA versions and legacy protocols, which are difficult to evolve and integrate into modern grid operations and open communication protocols.
- **Limited Integration of DER Visibility Data:** Some systems still have incomplete integration of DER data, limiting real-time visibility and coordination with grid conditions. This can hinder effective grid management and the optimization of DER.
- **Fragmented DER Interconnection and Visibility:** The integration of DER visibility into SCADA remains inconsistent, with few structured interactions between TSOs and DSOs. The lack of systematic coordination and standardized solutions limits forecasting accuracy, dispatch efficiency, and overall grid coordination, creating operational challenges as DER penetration grows.
- **Computational Limitations in Power System Analysis:** Traditional Optimal Power Flow (OPF) methods remain computationally intensive, limiting their effectiveness for real-time applications. Similarly, time-domain simulations and stability analyses — essential for assessing dynamic system behavior — often require significant processing time and are not yet fully integrated into real-time operational workflows. These limitations hinder the ability to respond swiftly to fast-evolving grid conditions, especially with the increasing penetration of variable renewable energy sources.
- **Limited PMU Deployment:** While PMUs are critical for monitoring fast system dynamics, their deployment remains relatively low across most transmission networks. The lack of widespread implementation and integration limits their potential, especially as the grid evolves with fewer synchronous generators.
- **Fragmented Training Simulation Systems for Operators:** Some utilities lack integrated SCADA training simulators, leading to gaps in simulation-based learning. In particular, training programs lack standardized SCADA simulators that include DER dynamics, HVDC operations, creating gaps in operator preparedness.



- **Regulatory Adaptation Challenges:** SCADA systems must continuously adapt to evolving regulatory frameworks (e.g., cybersecurity mandates, data sharing policies), which can be resource-intensive and slow down upgrades.
- **Missing standards for hybrid AC-DC systems:** While European Network Codes (e.g., Regulation 2016/1447) provide technical requirements for HVDC connections to the transmission grid there is a lack of comprehensive standards addressing the operation and coordination of hybrid AC-DC systems within the TSO networks. Significant gaps persist in the methodologies and control algorithms for hybrid AC/DC systems, particularly in multi-terminal HVDC configurations. These challenges are especially pronounced for DSOs, who often lack standardized frameworks for integrating such technologies at the distribution level. Addressing these issues will require not only technical innovation but also greater standardization and harmonization of control strategies, data models, and operational practices across TSOs and DSOs to ensure reliable and coordinated system operation

### 5.2.3. Opportunities

- **Enhanced Open-Source Development:** Adopting modular open-source solutions for key functionalities, allows for the seamless integration of diverse components.
- **Unified System Architecture:** Developing a standardized, modular SCADA framework with built-in flexibility to integrate various functionalities (monitoring, control, protection, forecasting) in one system.
- **Advanced Automation & AI Integration:** Enhancing decision-support tools with AI-based automation could reduce reliance on manual intervention while maintaining human oversight where necessary. Research projects are ongoing for introducing AI-based tools in SCADA control room; nevertheless, concerns regarding security and reliability have to be addressed.
- **Improved Interoperability Standards:** Promoting standardized data exchange formats (e.g., CIM/CGMES, IEC 61850) to enable seamless interaction between SCADA, EMS, and other control systems. Broader and more consistent use of these standards can reduce vendor lock-in, streamline data exchange, and enable seamless integration across multi-vendor environments.
- **Modernization for DER Integration:** Upgrading SCADA to enhance real-time monitoring, control, and forecasting of Distributed Energy Resources (DERs) will improve grid resilience and operational efficiency. This includes the integration of new tools and flexibility mechanisms that can optimize grid operations, improve efficiency, and support the dynamic nature of DERs within the grid.
- **Interoperability Improvements for DER and HVDC:** Standardizing communication protocols between SCADA, DERMS, and HVDC systems could enhance seamless grid operations and DER market participation.



- **Enhanced DSO-TSO Data Sharing:** Strengthening communication protocols and increasing data exchange frequency between DSOs and TSOs can improve visibility into distribution networks, leading to better system operations.
- **Integrating Cloud and Edge Computing for Scalable and Grid Intelligence:** Cloud and edge computing offer complementary opportunities to enhance grid management. Cloud-based SCADA and analytics platforms enable scalable data storage, centralized processing, and advanced forecasting capabilities. In contrast, edge computing supports low-latency decision-making by processing data closer to the source — ideal for real-time control and local automation. Together, these technologies can improve system responsiveness, resilience, and scalability in increasingly decentralized energy systems
- **Cybersecurity-Enhanced SCADA Architectures:** Strengthening security measures, such as zero-trust architectures and AI-driven threat detection, can mitigate cyber risks while maintaining operational efficiency.
- **Predictive Maintenance with AI:** AI and machine learning offer powerful tools for predictive maintenance, helping to reduce system downtime and extend asset life. These technologies can support advanced diagnostics by identifying fault locations and pinpointing which grid components are contributing to performance issues.
- **Expansion of PMU Utilization:** Increased deployment of PMUs for real-time state estimation and stability monitoring could improve grid security and operational foresight.
- **Enhanced Data Management Solutions:** Innovative data management tools, based on various technologies, could optimize historical and real-time data analysis, improving insights for grid operations.
- **Growing Role of DC Systems:** As DC interconnections expand, automated control systems could enhance grid resilience and cross-border energy exchange.
- **Advanced Training Simulators for Future Control Centers:** Developing realistic training scenarios incorporating DER flexibility, HVDC operations, and AI-based decision support tools can improve operator readiness.
- **Incremental System Upgrades:** Migration to newer SCADA versions ensures gradual improvements in system capabilities without disrupting existing operations.

#### 5.2.4. Threats

- **Cybersecurity Risks with Increased Connectivity:** Growing interconnectivity between SCADA, DERMS, and external data sources increases exposure to cyber threats and system vulnerabilities. When open-source tools are developed the cybersecurity must own great importance and its design from the early development stage must be included.



- **Regulatory and Compliance Challenges:** Adapting to evolving regulatory frameworks for grid modernization and DER integration may impose additional compliance costs and operational constraints.
- **Complexity of Large-Scale System Upgrades:** Transitioning to newer SCADA versions or integrating new functionalities can be complex, requiring extensive testing to ensure system robustness and reliability.
- **Growing Data Management Demands:** The increasing volume of real-time grid data and the need for high-frequency updates can strain existing computational resources and system infrastructure.
- **Resistance to Change:** Organizational inertia and reliance on legacy vendors may slow the adoption of innovative SCADA solutions, delaying necessary advancements in grid operations.
- **Building Trust and Operator Adaptability in AI-Driven Grid Operations:** The integration of AI into critical grid operations raises concerns around transparency, accountability, and the reliability of automated decision-making. At the same time, transitioning to AI-supported workflows requires significant cultural and operational shifts in control rooms, including retraining staff and overcoming resistance to automation.
- **Data Overload and Latency Challenges:** The surge in real-time data from PMUs, DERs, and IoT devices could overwhelm SCADA/EMS platforms if not managed with scalable data architectures.
- **Regulatory and Standardization Barriers:** The lack of standardized frameworks for AI and PMU integration across TSOs and DSOs may slow down adoption.
- **Manual Intervention Requirements:** Despite automation advances, most control decisions require human intervention, which may limit rapid response capabilities in critical scenarios. Good balance is necessary to define the required role of humans in the intervention loop.
- **Data Storage and Scalability Constraints:** The increasing volume of real-time grid data, particularly with DER integration and PMU deployments, challenges existing storage and processing infrastructure.
- **Potential Shift in Responsibility with Open-Source SCADA Adoption:** If TSOs choose to adopt and deploy open-source SCADA systems, they may face a shift in operational responsibility compared to vendor-managed solutions. In such scenarios, the burden of ensuring system reliability, security, and compliance could increasingly fall on the TSO, potentially requiring greater internal expertise and risk management capacity. This shift, while offering flexibility and innovation, may also introduce new challenges in maintaining critical infrastructure.



### 5.3. Gaps

Table 5. Identified gaps

Gaps	Description	Associated InterSCADA Activities
Lack of Open-Source Solutions for Hybrid AC/DC Grids	While open-source SCADA systems are gaining traction, there is a gap in open-source solutions specifically designed for hybrid AC/DC systems. The development of flexible, modular SCADA frameworks that can accommodate hybrid grids is limited, reducing the ability to customize and adapt to evolving requirements.	InterSCADA develops and releases its own platform (in the Task 3.3), which hosts only open-source components, based on the SCADA features and the optimal operation of the AC/DC power system networks.
Inadequate Integration of Hybrid AC/DC Systems in Legacy SCADA	Legacy SCADA systems, designed for traditional AC-based grids, lack the capability to handle the complexities of hybrid AC/DC networks. These systems often fail to integrate DC-based components effectively, leading to inefficiencies and missed opportunities for optimized grid management.	Several algorithms are developed by InterSCADA, in its WP2, that enhance the situational awareness and improve operation and stability in hybrid AC/DC power systems.
Limited Modular Design for Customization and Scalability	SCADA systems for hybrid AC/DC grids need to support modular designs to allow for easy upgrades, integrations, and future technology adoption. Current systems often lack the flexibility to meet the diverse needs of grid operators and are not built to scale easily as hybrid grid adoption increases.	The InterSCADA algorithms for the AC/DC systems are deployed as microservices (in Task 3.1), focusing on their standard interfaces to preserve their modularity.  Also built around a modular architecture, WP3 will develop the InterSCADA platform—an open-source, vendor-independent SCADA solution designed





		for fully automated operation of AC/DC power systems across all voltage levels.
Limited Real-Time Data Synchronization Between AC and DC Subsystems and Transmission and Distribution	Current SCADA systems often face to provide seamless real-time data synchronization between AC and DC subsystems due to differences in control philosophies, data sampling rates, and communication protocols. These technical mismatches complicate unified system monitoring and coordinated control. Additionally, limited integration between TSO and DSO data flows — often due to proprietary systems and inconsistent data models — further hinders end-to-end visibility and slows operational decision-making	InterSCADA works, in Task 4.1, on the interoperability with various communication protocols and standards to achieve an advanced data acquisition of AC/DC grid assets.
Missing data exchange among TSOs and DSOs for DER monitoring	Effective coordination between TSOs and DSOs is hindered by fragmented data exchange mechanisms and system incompatibilities. This is particularly critical for monitoring and managing DERs, where TSOs require timely, granular data from DSO networks. However, current data-sharing practices are inconsistent, with misalignments in data formats, communication protocols, and update frequencies.	The InterSCADA platform interfaces the existing legacy systems of DSOs and TSOs, in its Task 3.4, favoring a smooth and efficient data exchange.
Scalability Limitations in Data Infrastructure for	As hybrid AC/DC grid deployments grow, existing SCADA and data infrastructures face significant scalability challenges. Legacy systems are often not equipped to	The InterSCADA platform has the scalability among its main objectives. Scalability is achieved in Task 3.3 with the



Expanding Hybrid Grid Solutions	manage the increasing volume, velocity, and variety of data generated by diverse network elements and dynamic interconnections. Addressing these challenges might require modular and flexible architectures that can scale efficiently while maintaining system reliability and real-time performance.	interconnections of the platform components and the distributed databases.
Inadequate Support for Dynamic Power Flow Management in Hybrid Systems	Hybrid AC/DC systems present unique challenges in power flow management, including circular flows and power flow reversals that do not exist in traditional AC grids. Effectively managing the AC/DC dynamics requires advanced real-time optimization algorithms and control strategies. However, most existing SCADA systems lack the computational capabilities and algorithmic support to handle these conditions, limiting the ability to optimize grid performance and ensure stability under hybrid configurations.	InterSCADA improves, in its Task 2.2, state-of-the-art methods for optimized power flow in hybrid AC/DC-system accounting for security constraints and enhanced modelling of DC elements. The applicability of the developed solutions are tested, in the context of WP5, in the pilot demonstrators.
Lack of Flexibility for Multi-Vendor Grid Integrations	Vendor-specific SCADA systems limit the integration of diverse hardware and software components, which is a critical challenge for hybrid grids that require compatibility across multiple vendors, technologies, and communication protocols	InterSCADA complements the limitations of the existing legacy systems by offering the interface and interconnection to its own SCADA platform, as developed in the Task 3.4.
Insufficient Training Tools for Operators on Hybrid AC/DC	While operator training simulators exist for traditional grid operations, there is a lack of comprehensive training solutions that simulate the	A Graphical User Interface (GUI), specifically dedicated for the AC/DC systems, will be developed





System Management	complexities of hybrid AC/DC grid operations. Without these tools, operators may not be fully prepared to manage hybrid systems efficiently, especially during critical scenarios.	by InterSCADA (Task 3.5) to improve grid operators activities. Moreover, WP6 focuses on the dissemination of technical recommendations regarding the management of AC/DC grids.
Being prepared for AI and Advanced Analytics for Hybrid Grid Control	The potential of artificial intelligence (AI) and machine learning to optimize real-time control and decision-making in hybrid AC/DC systems remains underexplored in SCADA systems. These technologies can help improve grid stability and efficiency, but they are not yet integrated into many existing solutions.	A dedicated, trained AI artefact (including AI-OPF, AI-based instability detection and AI-based decision support modules) for AC/DC systems will be developed, in Task 2.4, and tested in the Spanish pilot (Task 2.5) of the project.
Insufficient Handling of System Disturbances and Faults in Hybrid AC/DC Grids	Hybrid AC/DC grids can be subjected to disturbances that can affect AC or DC parts of the system or even both simultaneously. Current resilience strategies, designed primarily for traditional AC grids, are insufficient for handling the unique challenges of hybrid grids. These systems require novel fault detection, isolation, and recovery approaches, but existing solutions do not adequately address the complexities introduced by integrating DC components.	The detection of instability situations (overvoltages, power oscillations, sudden changes in frequency, etc.) and the implementation of ancillary services for AC/DC grids are part of Task 2.3. Moreover, Task 4.3 works on dynamic security assessment solutions for the InterSCADA environment.
Limited Data Security and Privacy Measures for Hybrid Grid Operations	As hybrid AC/DC systems incorporate more decentralized, dynamic components, the risks related to cybersecurity and data privacy increase. Existing SCADA systems may not be designed to	InterSCADA releases novel cyber-physical security solutions that cover preventive and corrective security approaches (in Task 4.2), based on an



	handle the complex security requirements of hybrid systems, which could expose them to vulnerabilities and threats.	innovative “virtual redundancy” method.
Complexity in Managing Hybrid Grid Ancillary Services and Stability	Hybrid brings the opportunity to introduce new types of ancillary services for grid stabilization, including active power support and frequency regulation. SCADA systems need to be updated or enhanced to manage these new services effectively and ensure grid stability, but legacy systems are often insufficient in this regard.	Ancillary services offered for improving frequency stability (considering both nadir/zenith and RoCoF limitations) are developed in Task 2.3. Such solutions are part of the demonstrators in Greek and French pilots (Tasks 5.3 and 5.5, respectively).

## 5.4. Survey

To broaden the scope of the study and increase confidence in the conclusions, a set of questions was prepared and distributed to various SCADA system users. A total of 22 participants—representing both TSOs and DSOs—completed the survey. The full set of questions and available response options can be found in **Appendices**. This section will focus on the results obtained.

Firstly, the survey aimed to identify the type of SCADA/EMS/DMS/ADMS currently used in the participants’ organization, with 50% of respondents stating they use *Legacy, monolithic SCADA only*, while 18.2% use *Modular open-source SCADA*. The rest reported having alternative systems, some of which included *Monolithic SCADA with LFC module*, *Sonnen SW system*, and *Legacy and open-source module*. Figure 28 illustrates this distribution of answers.



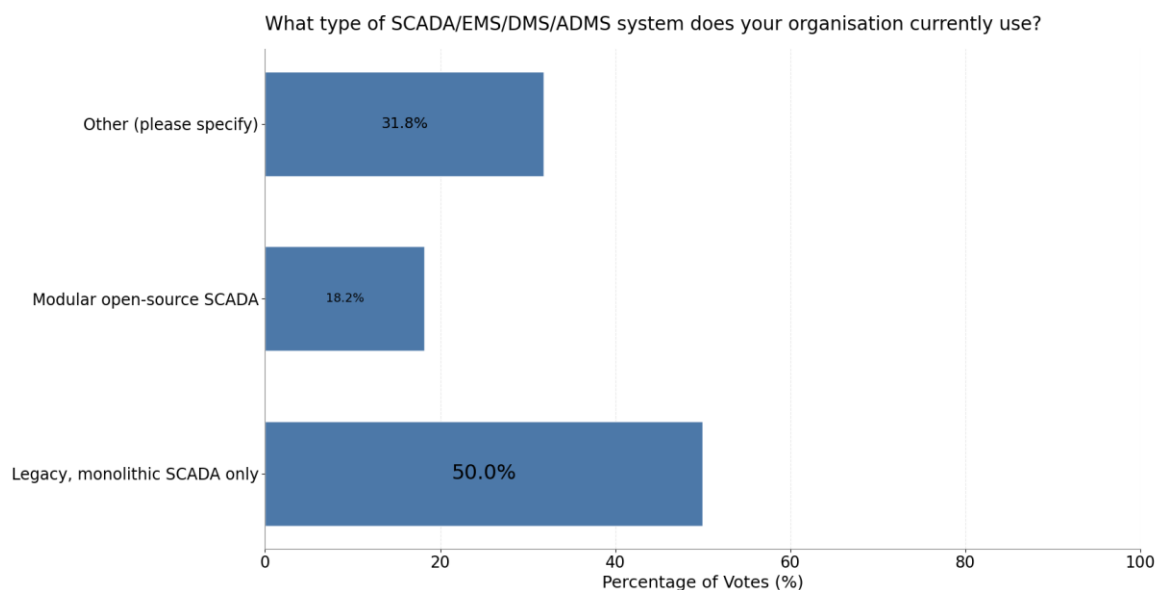


Figure 28. Survey Results – Responses to Question 1

Secondly, the survey focused on understanding the users' level of satisfaction with their current system; it was observed that most participants are either satisfied or at least not dissatisfied with the system they are currently using, according to the results presented in Figure 29.



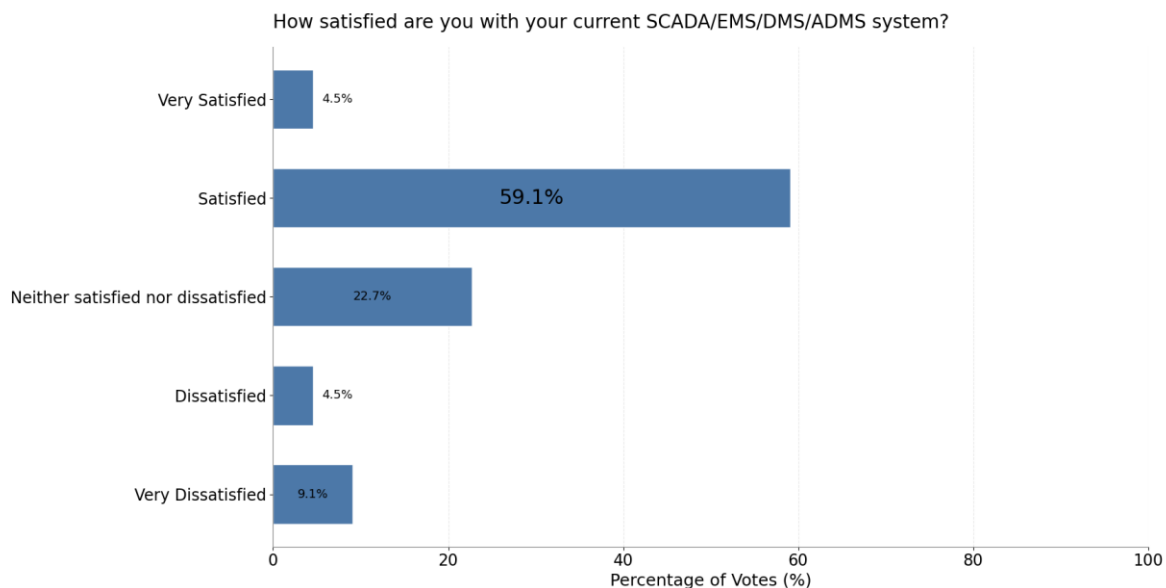


Figure 29. Survey Results – Responses to Question 2

Next, participants were asked how important the integration of DC technology is in their systems. As detailed in Figure 30, the responses were highly varied, though slightly skewed toward the perception that this aspect is not critical for them.



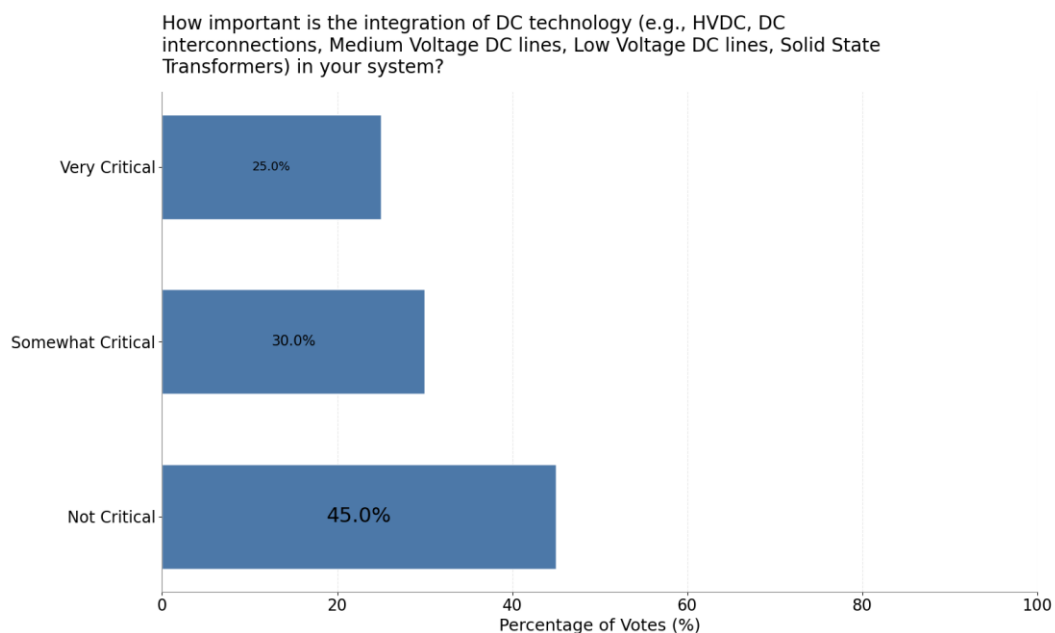


Figure 30. Survey Results – Responses to Question 3

The survey also allowed us to recognize that more than 50% of the participants do not have a SCADA/EMS/DMS/ADMS system that support the management of DC grids, as shown in Figure 31.

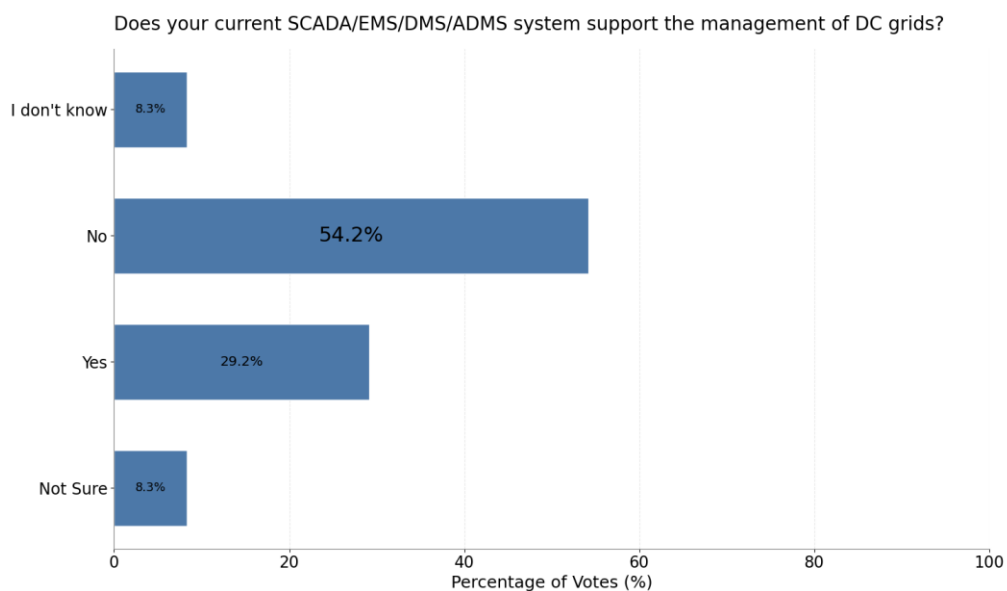


Figure 31. Survey Results – Responses to Question 4



The question related to the challenges of integrating DC grids with their current AC SCADA/EMS/DMS/ADMS system, whose results are shown in Figure 32, received highly varied responses. The selection of the 'Other' category was predominantly attributed to participants' limited or non-existent experience with the integration of DC grids into their current infrastructure.

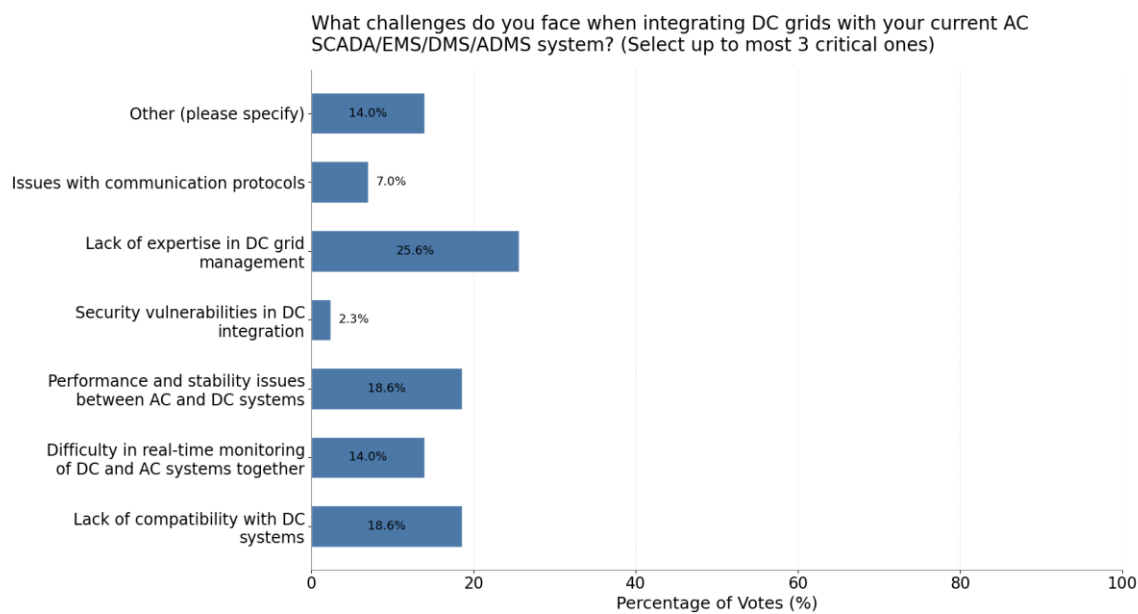


Figure 32. Survey Results – Responses to Question 5

Participants were also asked how important they considered the development of new tools to address DC technologies, using a scale from 1 (i.e., not necessary at all) to 5 (i.e., extremely important). The average of the received responses was 3, out of 5, indicating a moderate level of perceived importance (see Figure 33).



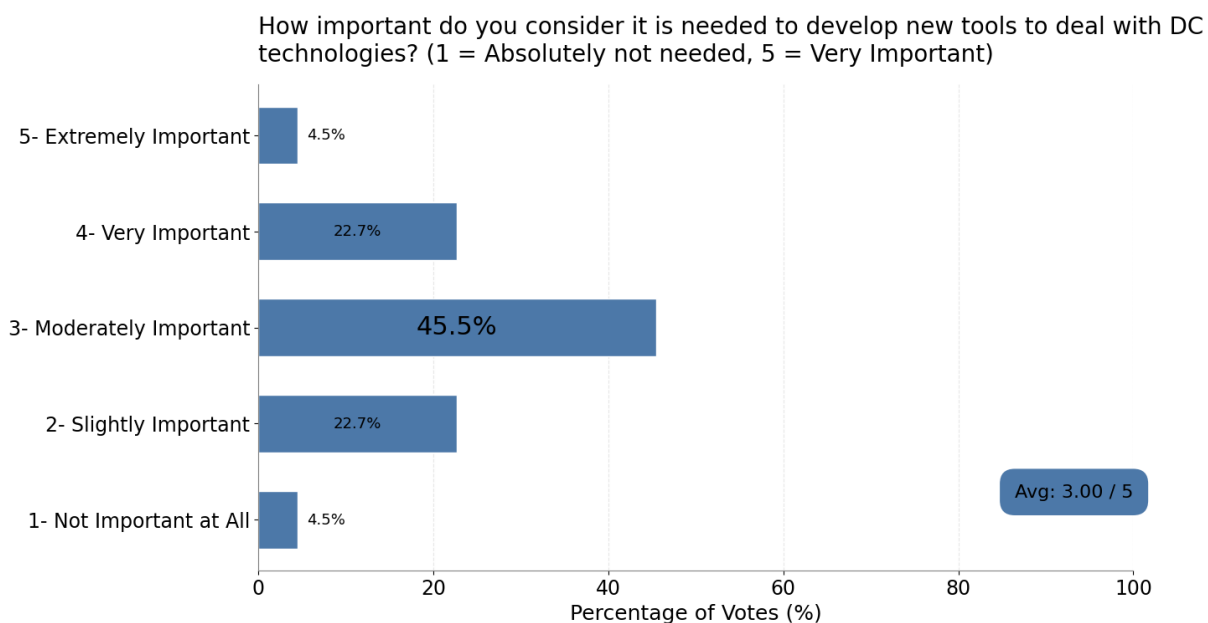


Figure 33. Survey Results – Responses to Question 6

In addition, according to Figure 34, we see a clear lack of visibility regarding DER generation/consumption connected to the distribution grid.

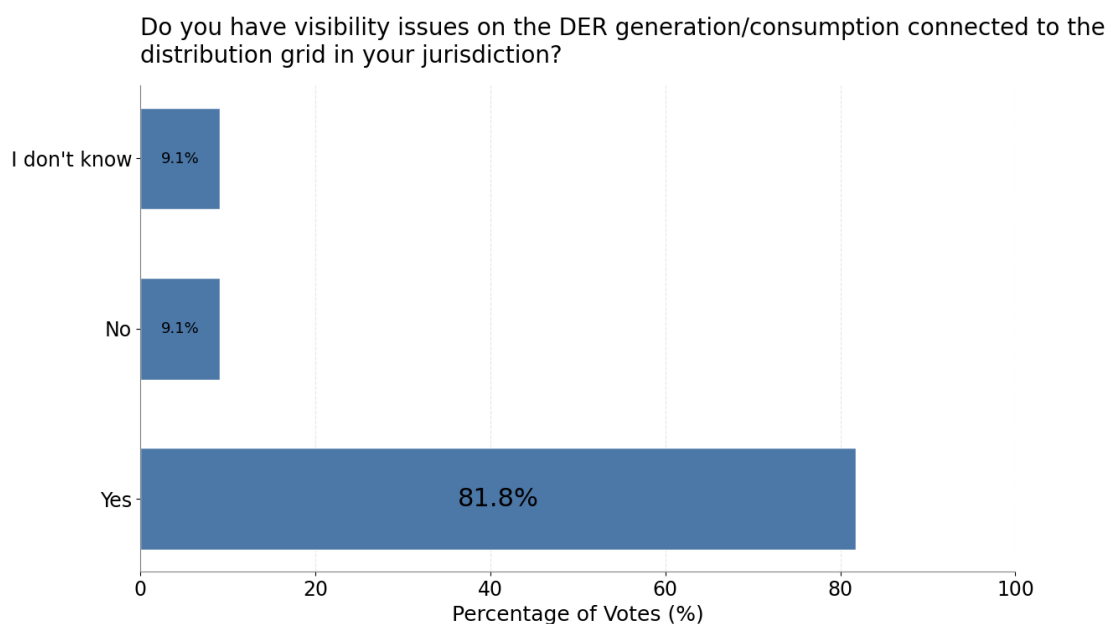


Figure 34. Survey Results – Responses to Question 7

Regarding the main technical challenges in managing DER through your current SCADA/EMS/DMS/ADMS system, the collected data, shown in Figure 35, indicates that all



the proposed options were considered relevant by at least one participant. The 'Other' option was justified with the following responses:

- *'Lack of integration of LV grids in SCADA/EMS/DMS/ADMS Systems'*
- *'Limitations from DERs' side to support more advanced managing methods.'*
- *'Stability issues'*
- *'Handling the bottleneck and rebalance the power within the bidding zone, without knowing where they are and how much they can be regulated.'*
- *'What about DER connected to the LV grid, usually SCADA doesn't cover LV grid'*

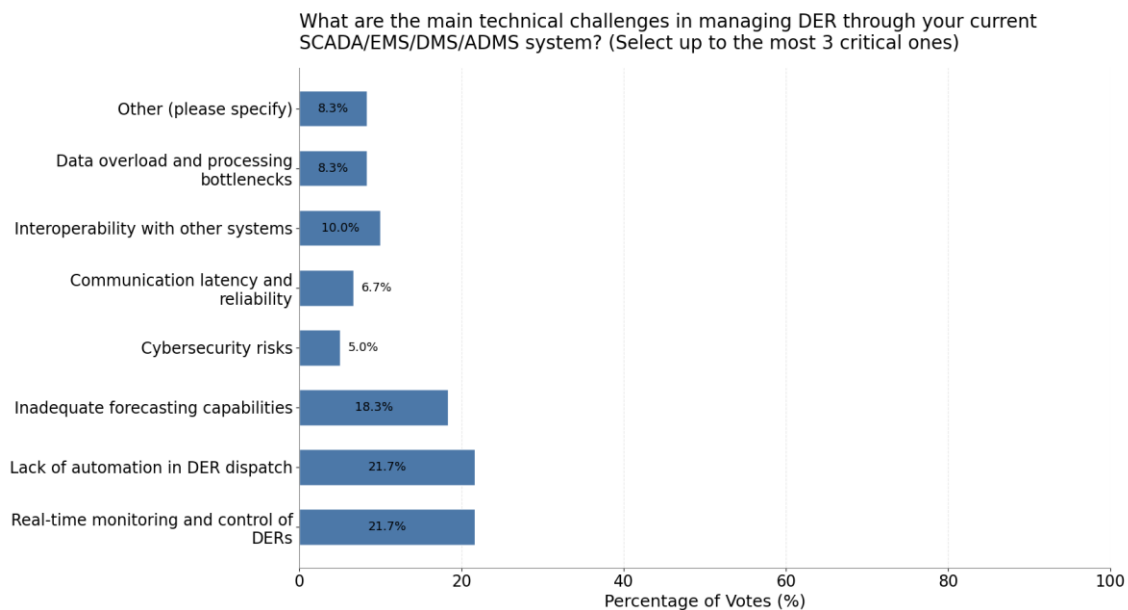


Figure 35. Survey Results – Responses to Question 8

Next, we aimed to assess the relevance of the ability to manage AC and DC systems and DER in a single SCADA/EMS/DMS/ADMS platform, once again using a scale from 1 (i.e., not important) to 5 (i.e., very important). The average score obtained from the responses was 3.82 out of 5, indicating that this aspect is perceived as important by the participants. The breakdown of the responses is illustrated in Figure 36.





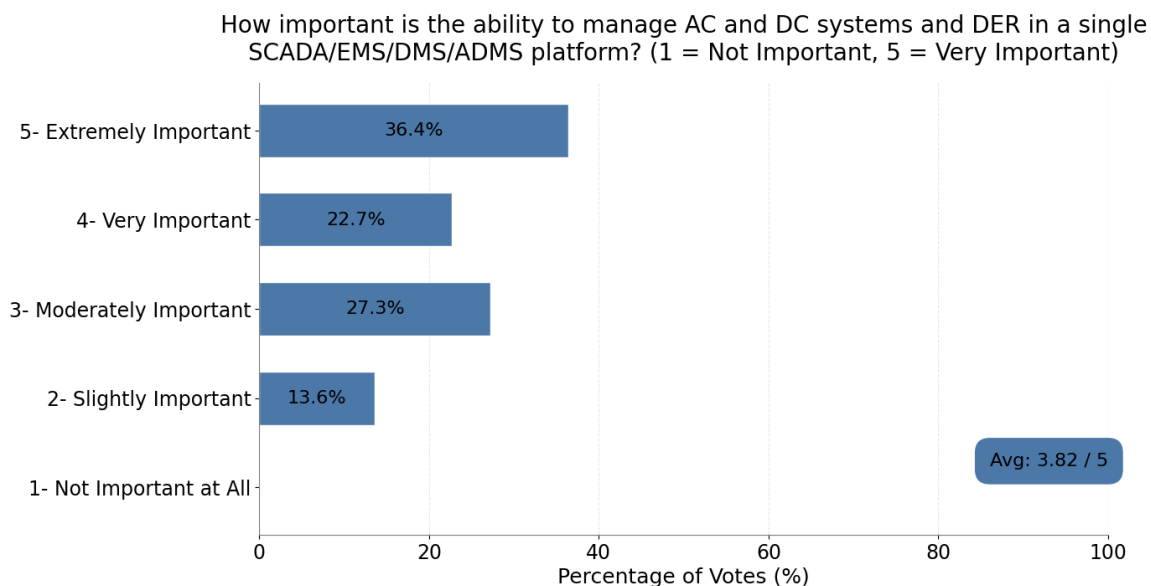


Figure 36. Survey Results – Responses to Question 9

In question 10 (see Figure 37), participants were asked to identify the three most important factors when considering an upgrade to SCADA/EMS/DMS/ADMS; the responses *Scalability and Flexibility*, *Security, System Reliability and Resilience* and *Real-time Monitoring and Control* emerged as the top three most frequently selected.

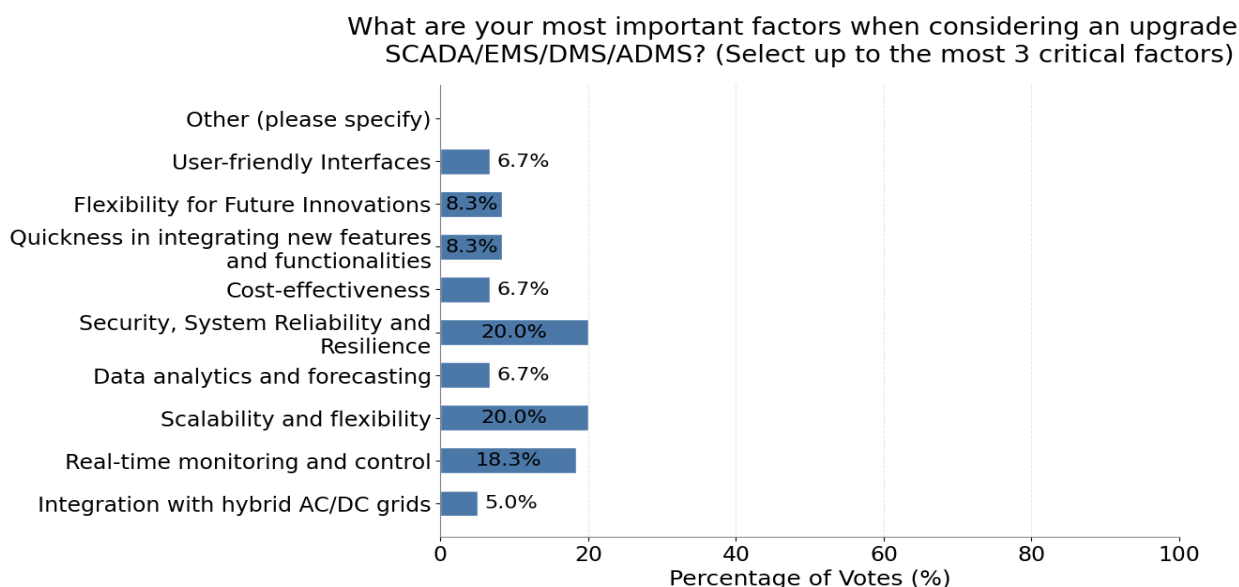


Figure 37. Survey Results – Responses to Question 10



We also consider relevant to understand how frequently participants need grid code updates to support the integration of hybrid AC/DC systems and DER, resulting in a moderate frequency. The distribution of participant responses is displayed in Figure 38.

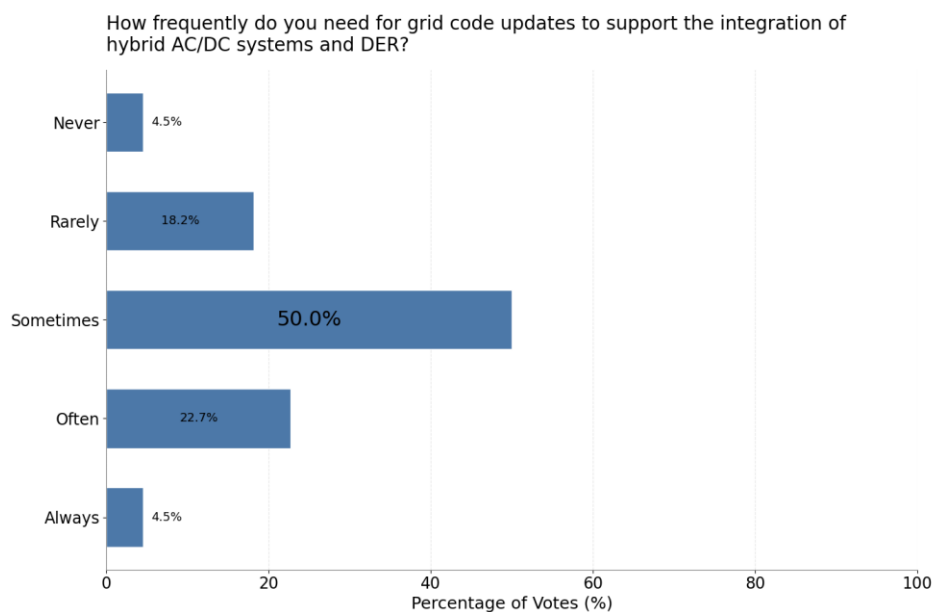


Figure 38. Survey Results – Responses to Question 11

Lastly, participants were asked to indicate their preference regarding the architecture of future SCADA/EMS/DMS/ADMS system, with *Modular system* and *Combination of Modular System and Monolithic System* emerging as the most commonly selected options, as illustrated in Figure 39.



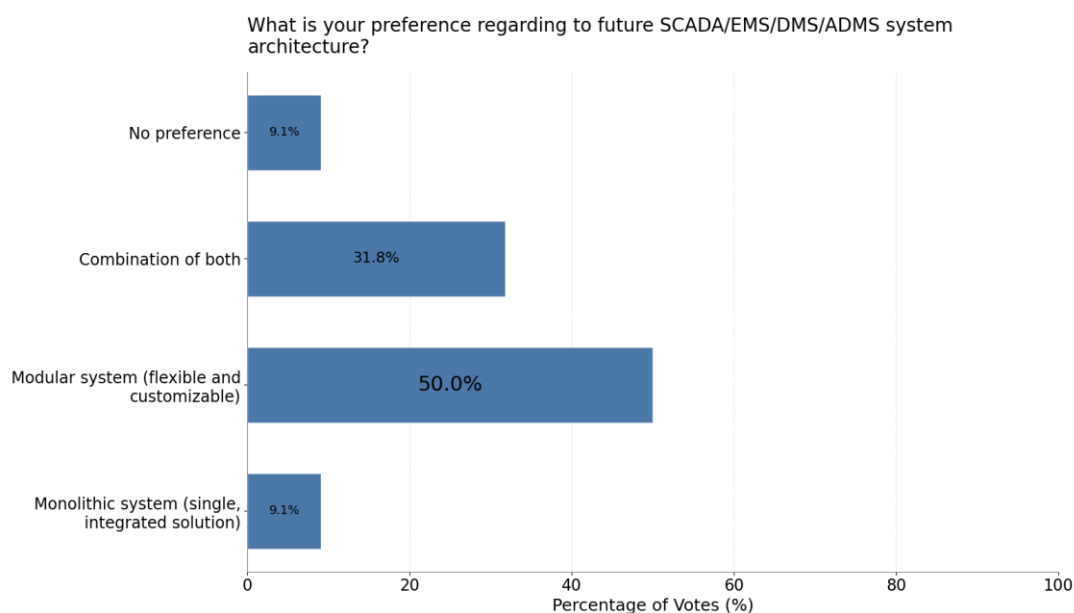


Figure 39. Survey Results – Responses to Question 12

#### 5.4.1. Analysis of Survey Results

The results of the conducted survey reinforce the key outcomes of the SWOT analysis and gaps (Section 5.2 and 5.3, respectively) and provide insights into the priorities and focal points of the InterSCADA project's key objectives.

Responses to Question 1 highlight the widespread use of monolithic, legacy solutions. Combined with the dissatisfaction expressed by more than one-third of respondents regarding their current SCADA systems (Question 2), this reinforces the need for InterSCADA's activities focused on developing and releasing an advanced, modular, open-source SCADA platform that benefits the energy community. As addressed in WP4 of the project, the InterSCADA platform will maintain compatibility with the legacy systems currently used by TSOs and DSOs. This aligns with the survey responses to Question 12, which indicate a partial willingness to combine monolithic and modular solutions.

In this regard, the answers to Question 9—on the importance of having a unified system to manage all grid assets and functionalities—support the concept of a modular InterSCADA platform capable of hosting all services for AC/DC grid monitoring and control (WP3 and WP4), along with a unified data layer (Task 4.1) that accommodates various data communication protocols and a broad range of grid devices.

The partial preference for monolithic solutions, as indicated in the survey, can be linked to the threats of cybersecurity risks, limited scalability, and upgrade challenges—issues that



were also identified in the SWOT analysis and confirmed by the survey results. In this context, it is important to highlight Task 4.2 of the project, titled “Preventive and Corrective Cyber-Physical Security Measures.” This task aims to “develop and test a novel cybersecurity channel to ensure the integrity, consistency, and security of communications between the different actors of the AC/DC grids,” to be integrated into the InterSCADA platform.

Significant input also concerns DC technology and its integration into existing networks. While most respondents reported that current solutions lack the capability to manage DC networks (Question 4), the need for such solutions was identified as a high priority (Question 6). The issues of compatibility, real-time monitoring, and stability performance—highlighted in responses to Question 5—are consistent with the gaps identified in the SWOT analysis, including inadequate AC/DC integration, lack of data synchronization, and insufficient management of disturbances in AC/DC networks. These weaknesses are directly addressed by tools being developed in InterSCADA WP2, including State Estimation and OPF (Task 2.2), algorithms for stability management and ancillary services (Task 2.3), and monitoring solutions equipped with dedicated DC sensors (Task 2.1).

Furthermore, the responses to Question 7 are particularly relevant: the lack of visibility of DERs connected to distribution grids was reported as a common challenge. This issue also emerged during interviews with system operators. As an opportunity, SCADA systems should be upgraded to enhance the monitoring and controllability of DERs (as highlighted in Question 8). InterSCADA tackles this by enhancing algorithms and tools to improve situational awareness, operational efficiency, and network stability (WP2). Additionally, the challenges related to data management and DER communication interoperability are addressed in Task 4.1, which focuses on developing a data management layer. This layer will be integrated into the InterSCADA platform to ensure seamless data exchange with a wide range of DER asset types and communication protocols.



## 6. Conclusions

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This deliverable presents an analysis of the needs and requirements of System Operators (SOs) concerning the integration of hybrid AC/DC systems, with a specific focus on the short-term upgrades required for SCADA, EMS, and ADMS systems.

A comprehensive overview of the state of the art in monitoring and control systems is provided, with a detailed examination of various functionalities and available implementation options. Additionally, the section dedicated to hybrid AC/DC grids offers a thorough outline that supports the understanding of the associated challenges and gaps resulting from the increasing adoption of DC technology.

A SWOT analysis, reflecting the perspectives of SOs, highlights key aspects of SCADA systems. Notably, the limitations of legacy solutions—particularly in terms of flexibility and the rapid introduction of new SCADA features—and the need to enhance real-time monitoring and visibility of grid assets across all voltage levels have emerged as priorities for improving electrical grid management. These findings are further supported by the results of the survey conducted among DSOs and TSOs.

The gap analysis contributes significantly to shaping the focus areas of the InterSCADA developments. The identified need for modular and open solutions validates the approach adopted in the platform's design, which emphasizes the data layer for seamless communication with grid devices. Moreover, the development of advanced algorithms is highlighted as essential for improving grid stability and control, especially in the context of high DER penetration and hybrid AC/DC networks.

Finally, this work provides guidance for InterSCADA's contributions to regulatory and standardization activities related to AC/DC networks.



# Appendices

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## Appendix A - Interview questions

The questions that guided the interviews conducted with the SOs are reported hereafter.

### SCADA:

1. About the SCADA currently in place in your company:
  - a. Which are the operative functionalities (for monitoring, control, protection)?
    - i. Are they all automated or manual intervention is, in some cases, needed?
  - b. Considering the overall system architecture: which are the interconnected components? (i.e., data exchange interfaces: which field devices, GUI, ADMS)
  - c. How does your current SCADA system handle interoperability with other systems and devices from different vendors?
    - i. How does interoperability impact the efficiency and reliability of your grid operations?
    - ii. Are there specific interoperability standards or protocols that your system adheres to? If so, which ones? What are the challenges faced in achieving seamless interoperability within your grid's operational framework?
2. Which are the current issues / limitations of the SCADA in place?
3. Does this existing SCADA need to be adapted / modified, in order to pursue the modernization of grid operations (e.g., DER control)? How?
4. What emerging technologies do you foresee having the most significant impact on SCADA systems in the near future?
  - a. How do you handle the vast amounts of data generated by the SCADA system? What data management strategies are in place?
  - b. How do you ensure the HMI is designed to minimize the risk of human error?
  - c. How do you train the operators? Do you have a simulator in the current SCADA?
  - d. Are there any AI/data analytics planned to be integrated (or considered) into your SCADA system? If so, what functionalities can they support in the future?
5. What is the necessity of real-time measurements for monitoring and control operations? What is the role and usage of PMUs (actual and planned)?



**AC/DC system:**

6. What is the existing or foreseen role of DC in your organization? Which are the needs, related to the integration of AC/DC systems?
7. Which AC/DC technologies are envisioned to be integrated in your grid?
  - a. How is/will be the DC sub-system topology (radial, line-to-line, meshed)?
8. Which will be the monitoring, control, and protection capabilities and solutions of the AC/DC grid?
9. Which are impacts of AC/DC systems on SCADA? How should the existing SCADA be adapted, to operate the AC/DC grid?
10. Are there specific regulations, grid codes and standards for AC/DC systems in transmission and distribution grids? Which are their gaps and ongoing work?

**Legacy / Open SCADA:**

11. Are there limitations and issues related to the “proprietary / legacy” condition of SCADA?
12. How should InterSCADA be designed to complement and enhance "legacy" SCADA?
13. Have you considered migrating from a monolithic to a modular system?
  - a. What are the primary drivers behind such considerations?
  - b. How do modular solutions impact scalability and maintainability compared to monolithic systems?
14. What cybersecurity measures are in place to protect your SCADA system from potential threats and vulnerabilities? Are there any specific cybersecurity standards or regulations that your organization follows to ensure the security of your SCADA system?





## Appendix B - Survey questions

The initial introductory questions collect information regarding the name, contact details, affiliated organization, and organization type (TSO or DSO) of the survey respondent. The technical questions of the survey are reported hereafter.

- 1. What type of SCADA/EMS/DMS/ADMS system does your organization currently use?**
  - Legacy, monolithic SCADA only
  - Modular open-source SCADA
  - Other (Please specify): \_\_\_\_\_
- 2. How satisfied are you with your current SCADA/EMS/DMS/ADMS system?**  
(1 = Very Dissatisfied, 5 = Very Satisfied)
- 3. How important is the integration of DC technology (e.g., HVDC, DC interconnections, Medium Voltage DC lines, Low Voltage DC lines, Solid State Transformers) in your system?**
  - Not Critical
  - Somewhat Critical
  - Very Critical
  - Not Sure
- 4. Does your current SCADA/EMS/DMS/ADMS system support the management of DC grids?**
  - Yes
  - No
  - I don't know
- 5. What challenges do you face when integrating DC grids with your current AC SCADA/EMS/DMS/ADMS system? (Select up to most 3 critical ones)**
  - Lack of compatibility with DC systems
  - Difficulty in real-time monitoring of DC and AC systems together
  - Performance and stability issues between AC and DC systems
  - Security vulnerabilities in DC integration



- Lack of expertise in DC grid management
  - Issues with communication protocols
  - Other (Please specify): \_\_\_\_\_
- 6. How important do you consider it is needed to develop new algorithms to manage grids that include DC technologies (related to, e.g., different dynamics, state estimation for hybrid AC/DC grids, instabilities, time frame requirements)? (1 = Absolutely not needed, 5 = Very Important)**
- 7. Do you have visibility issues on the DER generation/consumption connected to the distribution grid in your jurisdiction?**
- Yes
  - No
  - I don't know
- 8. What are the main technical challenges in managing DER through your current SCADA/EMS/DMS/ADMS system? (Select up to the most 3 critical ones)**
- Real-time monitoring and control of DERs
  - Lack of automation in DER dispatch
  - Inadequate forecasting capabilities
  - Cybersecurity risks
  - Communication latency and reliability
  - Interoperability with other systems
  - Data overload and processing bottlenecks
  - Other (Please specify): \_\_\_\_\_
- 9. How important is the ability to manage AC and DC systems and DER in a single SCADA/EMS/DMS/ADMS platform? (1 = Not Important, 5 = Very Important)**
- 10. Regarding cyber-threats for SCADA: Could DER integration and DC technologies affect the cybersecurity of your SCADA/EMS/DMS/ADMS? (1 = Very Insecure, 5 = Very Secure)**
- 11. What are your most important factors when considering an upgrade to SCADA/EMS/DMS/ADMS? (Select up to the most 3 critical factors)**
- Integration with hybrid AC/DC grids



- Real-time monitoring and control
- Scalability and flexibility
- Data analytics and forecasting
- Security, System Reliability and Resilience
- Cost-effectiveness
- Quickness in integrating new features and functionalities
- Flexibility for Future Innovations
- User-friendly Interfaces
- Other (Please specify): \_\_\_\_\_

**12. How frequently do you need for grid code updates to support the integration of hybrid AC/DC systems and DER?**

- Never
- Rarely
- Sometimes
- Often
- Always

**13. What is your preference regarding to future SCADA/EMS/DMS/ADMS system architecture?**

- Monolithic system (single, integrated solution)
- Modular system (flexible and customizable)
- Combination of both
- No preference

**14. Any other comments or suggestions regarding SCADA solutions for integrating hybrid AC/DC grids or DER?**  
(Optional)



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