



Improvements in Operational Data Exchange

Report

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List of abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ATC	Available Transfer Capacity
BA	Balancing Authority
BEM	Business Excellence Models benchmarking
BES	Bulk Electric System
CAGM	Capacity Allocation and Congestion Management
CCC	Coordinated Capacity Calculator
CCR	Capacity Calculation Region
CGM	Common Grid Model
CGT	Gate Closure Time
CNTC	Coordinated Net Transfer Capacity
EBG	Electricity Balancing Guidelines
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
ERO	Electric Reliability Organization
EU	European Union
FB	Flow-based
FCA	Forward Capacity Allocation
GCC	Gulf Cooperation Council
GCCIA	Gulf Coordination Council Interconnection Authority
GLSK	Generation and Load Shift Key
IGM	Individual Grid Model
ISO	Independent System Operator
JWG	Joint Working Group
MISO	Midcontinent Independent System Operator
MO	Market Operator
MRO	Midwest Reliability Organization
MVP	Minimum Value Product

NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NRA	National Regulation Authority
NTC	Net Transfer Capacity
NYISO	New York Independent System Operator
O2O	One-to-one benchmarking
OMS	Outage Management Systems
OPDE	Operational Planning Data Environment
PJM	Pennsylvania-New Jersey-Maryland interconnection
RC	Reliability Coordinator
RF	Reliability First
RSC	Regional Security Coordinator
RTO	Regional Transmission Organisation
SB	Survey Benchmarking
SCDA	Supervisory Control and Data Acquisition
SERC	Southeastern Electric Reliability Corporation
SOGL	System Operation Guidelines
TC	Transfer Capacity
TRE	Texas Reliability Entity
TSO	Transmission System Operator
TTC	Total Transfer Capacity
WAPP	Western Africa Power Pool
WECC	Western Electricity Coordinating Council

1

Executive Summary

The Improvements in Operation Data Exchange, Rules and Protocols for Increased Coordination of Power Systems activities belong to the Optimised Operation Processes stream of the TEASIMED 2 project and are focused on identifying a Minimum Value Product for a Med-TSO coordination model targeting Outage Planning and Capacity Calculation.

The main outcomes can be summarised as follows:

1. Improvement in Operational Data Exchange

Effective coordination among Mediterranean TSOs relies on robust operational data exchange through SCADA/EMS systems. The assessment highlights the following:

Current status:

- EU-Mediterranean connected TSOs exchange comprehensive real-time and planning data through integrated SCADA/EMS systems.
- Non-EU Mediterranean and isolated TSOs provide only core operational data or have limited exchange due to infrastructure or geographical constraints.

Key data categories for SCADA-based exchange:

1. **Real-Time Operational Data:** system frequency, power flows, generator status, and demand.
2. **Grid Operational Security Data:** contingency analysis, stability margins, fault management, and restoration plans.
3. **Long-Term Planning Data:** capacity forecasts, demand projections, and renewable integration.
4. **Structure and Forecast Data:** grid topology, generation patterns, and predictive load balancing.

Benefits:

- Enhances visibility of interconnected grids, reduces blind spots, and improves system stability.
- Supports coordinated outage planning and accurate cross-zonal capacity calculation.
- Facilitates integration of renewable energy sources and informed operational decision-making.

Recommendations:

- Upgrade SCADA/EMS systems to improve interoperability and data granularity.
- Adopt standardised communication protocols for real-time and near-real-time exchange.
- Strengthen cybersecurity through role-based access, network segregation, and monitoring.
- Include isolated or non-EU TSOs in data exchange loops to enable full regional coordination.

2. Rules and Protocols for Outage Planning and Capacity Calculation

Enhanced coordination among interconnected TSOs

When Transmission System Operators (TSOs) are interconnected, they must coordinate outages and adopt a harmonised approach to computing cross-border capacity.

Outage coordination process

Outages of relevant grid elements shall be coordinated across different timeframes – at least on a yearly and weekly basis. TSOs should promptly inform neighbouring operators about any changes in real time.

As a Minimum Viable Product (MVP), TSOs shall exchange information on outages of all grid and generation elements that affect cross-zonal capacity (including tie lines and all elements connected to the substations associated with those tie lines). A continuous improvement of the outage coordination process is also recommended, following the progressive stages proposed in the report.

Cross-zonal capacity calculation

Cross-zonal capacity should be defined in a coherent and harmonised manner. As an MVP, the Net Transfer Capacity (NTC) approach should be applied using the minimum value rule. Each TSO shall compute NTC values at least on a yearly and monthly basis, updating them whenever significant changes occur in expected system scenarios (including those linked to outage planning). A continuous improvement of the capacity calculation process is also recommended, in line with the stages proposed in the report.

2

Introduction

The Mediterranean Transmission System Operators (Med-TSO) have launched a key initiative under the TEASIMED 2 project (Towards an Efficient, Adequate, Sustainable and Interconnected Mediterranean Power System), co-funded by the European Union. This initiative aims to enhance operational data exchange and coordination across Med-TSO countries. It builds on the foundational work carried out during the previous TEASIMED project and responds to the growing need for improved visibility and coordination in an increasingly interconnected Mediterranean power system.

The primary objective of TEASIMED 2 is to assess whether existing Supervisory Control and Data Acquisition (SCADA) systems, communication infrastructures, and exchange protocols are capable of providing comprehensive and timely visibility of neighbouring power systems. In parallel, the activity aims to strengthen the rules and protocols governing the coordination of power systems, which are essential for secure and efficient cross-border operations.

Enhanced visibility and quasi-real-time data exchange are critical to maintaining the security and reliability of interconnected power systems. They enable Transmission System Operators (TSOs) to promptly detect disturbances, assess their impacts, and coordinate effective responses to operational issues that may arise on interconnecting lines. To this end, Med-TSO seeks to foster a more robust and efficient communication framework that supports fast,

reliable, and secure operational data exchange.

A core component of this activity is a comprehensive assessment of existing data acquisition and exchange systems across Med-TSO members. It evaluates whether current systems are equipped with state-of-the-art functionalities required for effective cross-border data exchange and identifies potential technical and organisational gaps. Where necessary, upgrade requirements are analysed to support improved interoperability and operational coordination among neighbouring TSOs.

This report is structured into two complementary parts.

Part I focuses on evaluating the readiness of Med-TSO members to engage in operational data exchange. It examines the current level of preparedness, identifies challenges and limitations faced by individual TSOs, and analyses specific operational situations where information exchange is constrained. Based on surveys and case studies, this part proposes a harmonised set of operational data exchange protocols, which will be consolidated within the Med-TSO database (DBMED). Whilst the initial implementation of these protocols may present challenges, their long-term contribution to system security and reliability is expected to be significant.

Part II addresses the Rules and Protocols for Increased Coordination of Power Systems, within the Optimised Operation Processes stream of TEASIMED 2. It aims to support the progressive integration of Mediterranean power systems by enhancing coordination mechanisms related to adequacy, energy security, cross-border electricity exchanges, and renewable energy integration. The specific objective of this activity is to conduct a benchmarking of current practices applied by Med-TSO members in outage planning and capacity calculation. This benchmarking exercise is carried out by a Joint Working Group between CESI and Med-TSO, with the goal of identifying best practices and areas for improvement to support coordinated and secure operation of the Mediterranean power system.

Outage coordination

Outage coordination refers to the process of planning, reviewing, and approving the removal of power system components from service. It ensures that such outages do not adversely affect grid operation, especially when it is part of a large, interconnected system involving multiple stakeholders such as utilities, TSOs, and transmission companies.

The objectives of outage coordination are to:

- Maintain system reliability, ensuring stability and the security of the power system despite outages.
- Avoid congestion, minimising transmission constraints that can lead to inefficiencies.

- Ensure safety, protecting maintenance personnel and the public.
- Optimise maintenance, aligning outages to reduce total downtime and costs.
- Support market efficiency, by avoiding disruptions that could cause volatility in energy markets.

In this operational process the following types of outages are managed:

- Planned outages for maintenance, upgrades, or testing.
- Unplanned outages due to faults, accidents, or emergencies.
- Forced outages for immediate shutdowns due to equipment issues.
- Opportunity outages that should be performed when system conditions allow.

The outage coordination process usually consists of the major sub-processes listed in Table 2.1.

1	Outage request submission	Asset owners (e.g. generator or transmission owners) submit requests containing details such as dates, affected elements, duration, purpose, etc.
2	Preliminary screening	The coordinating authority (e.g. Regional Coordination Centres) checks for conflicts, system reliability risks, and overlapping outages.
3	Reliability assessment	Contingency analysis, load flow studies, and stability analysis are conducted and “what-if” scenarios are simulated to ensure the grid can handle outages under N-1 conditions.
4	Coordination among stakeholders	Outage windows are aligned with neighbouring system operators or utilities to ensure cross-border effects are considered in interconnections.
5	Approval or adjustment	The outage is approved if system reliability is unaffected; and rescheduling or reconfiguration is recommended if issues are identified.
6	Real-time monitoring and communication	Outage execution is confirmed and EMS/SCADA systems are used to monitor real-time conditions.

Table 2.1 Outage planning main sub-processes

To perform the activities relating to the sub-processes above, specific tools and techniques are required, including:

- Energy Management Systems (EMS)

- Contingency Analysis Tools
- Load Flow Simulators
- Reliability Assessment Tools
- Outage Management Systems (OMS)

Capacity calculation

Capacity calculation is the process of estimating the maximum amount of power (MW) that two interconnected grids or areas can transfer between each other under given operating conditions without compromising system security. It is usually carried out ahead of schedule on different time horizons, for example one year or one week ahead.

In interconnected power systems, capacity calculation is essential to ensure a secure and efficient exchange of energy across different regions or countries. It is rooted in a common grid model – a shared network representation – and supported by calculation methodologies that consider critical grid elements, contingency analyses, and probabilistic risk assessments.

The main objectives of capacity calculation are to:

- Maximise the use of available transmission capacity both internally and across cross-border interconnections.
- Maintain system reliability and security
- Facilitate cross-border electricity trade wherever energy markets have been established

Two main methodologies are used for capacity calculation:

- **Coordinated Net Transfer Capacity (CNTC):** calculates bilateral capacities between areas by considering network constraints conservatively. Often used in less meshed grids or where coordination is limited.
- **Flow-Based (FB):** considers the physical power flows across all network elements, offering a more granular and realistic assessment of capacity in highly interconnected grids (e.g. Continental Europe). The flow-based approach allows higher utilisation of the network whilst ensuring operational security.

The main requirements for reliable capacity calculation are as follows:

- A suitable grid model that allows the influences of neighbouring areas to be determined.
- Estimated generation and load patterns to simulate cross-border energy transfer (base case).

- A procedure to harmonise and agree on the input data among the relevant TSOs.
- Guidelines to perform the simulations of cross-border energy transfer in a realistic and transparent manner, considering operational security constraints (e.g. thermal limits, voltage stability), contingency analysis, cross-zonal exchanges, and loop flows.

Capacity calculation is managed by Transmission System Operators (TSOs), sometimes under the coordination of a regional entity, a Regional Coordinator, that oversees the calculation on their behalf.

The capacity calculation process generally consists of the main sub-processes shown in Table 2.2.

1	Transmission grid model definition	Each TSO develops a mathematical model describing the physical nodes and the connecting elements with associated voltages, angles, and power injections at the nodes consistent with physical constraints of the grid.
2	Common grid model definition	The Common Grid Model (CGM) sub-process is the responsibility of the Regional Coordinator and consists of merging the individual grid models so that flows on the tie-lines are consistent with the cross-border power exchange. This is an iterative activity starting from the collection of structural, forecast and scheduled data shared by TSOs and delivering CGMs adequate for the services to be performed as part of the operation and coordination of the regional electrical system, across all necessary timeframes. The CGMs will be used by the Regional Coordinator in the static and dynamic security assessment of the power system during operational planning activities.
3	Relevant assets definition	This covers the part of the grid under the responsibility of a TSO, close to the border, that affects the security of the interconnection and influences the values of transmission capacity on the border. TSOs develop a common methodology to evaluate the relevant assets and establish a single list to use as contingencies in the security assessment. TSOs also inform all the owners of the elements in the list.
4	Scenarios definition (base cases)	Based on feedback for the previous years, TSOs and Regional Coordinator agree on the scenarios to be prepared and the associated hypothesis.
5	Cross-border capacity calculation	Evaluation of the cross-border capacity for each TSO according to the definition of normal conditions and the N-1 security criterion.
6	Remedial actions available	To improve power system management under security conditions, each TSO defines operational actions needed to avoid cascading effects after the occurrence of a contingency on the relevant assets.
7	Final evaluation of cross-border capacity	The Regional Coordinator shares the final evaluation of cross-border capacity, taking into account all assumptions and data supplied by each TSO.

Table 2.2 Capacity calculation main sub-processes

3

Part I – Survey-Based Assessment of Operational Data Exchange

Figure 3.1 presents the Med-TSO Interconnectivity Chart – 2025 Situation¹, providing a consolidated overview of the existing synchronous areas, cross-border interconnections, and operational linkages among Mediterranean power systems, and their connections with Continental Europe and neighbouring regions. The figure highlights the heterogeneity of interconnection levels, system maturity, and operational synchronisation across the region, underlining the need for enhanced coordination and harmonised operational practices.

¹ Block sizes are illustrative and do not reflect country size or power system scale.

Partial-load feeding represents limited border areas or specific interconnection points, not a substantial share of national systems.

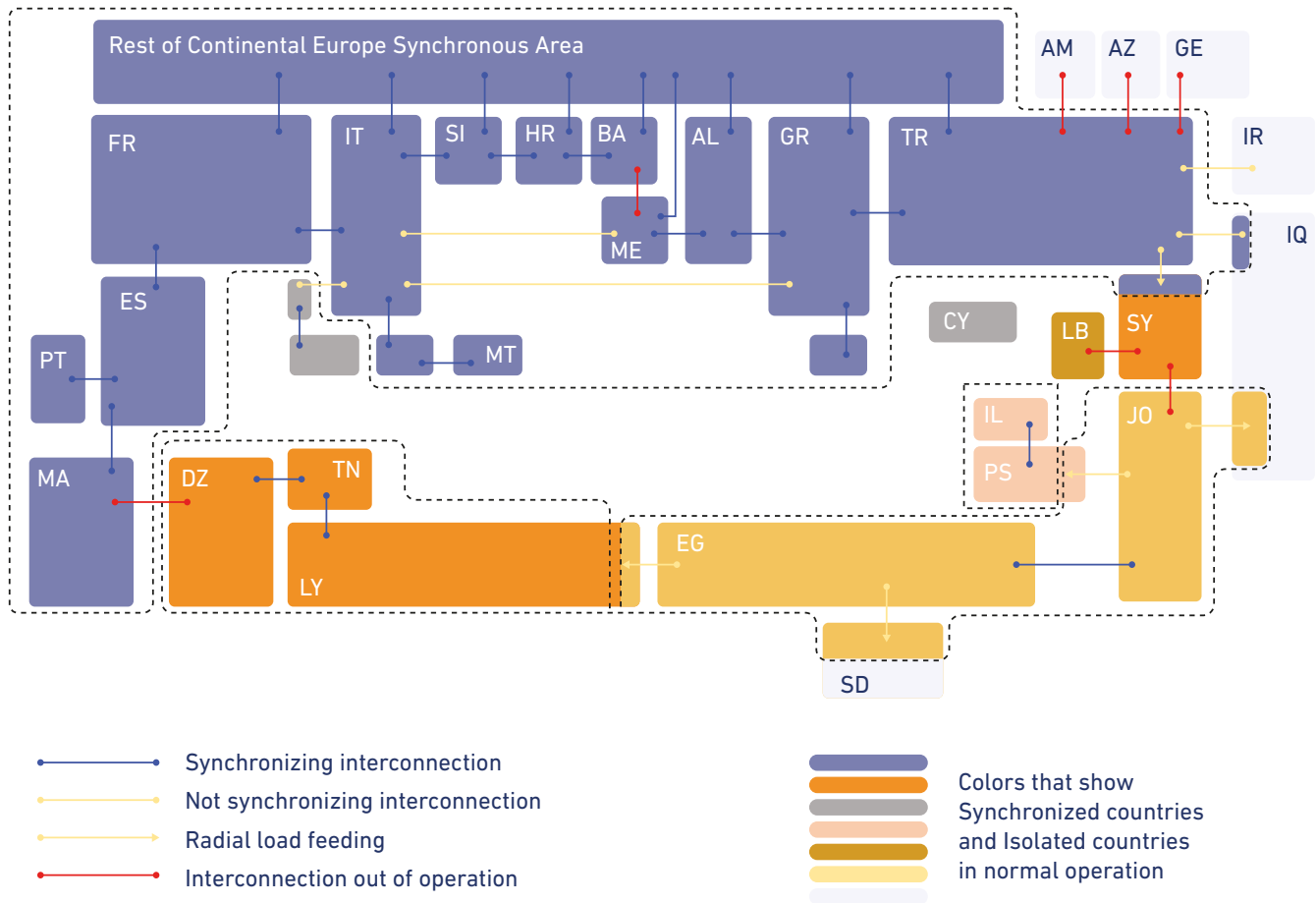


Figure 3.1 Current interconnection and synchronisation status for Med-TSO countries in 2025

Building on this regional snapshot, and by analysing the capabilities of existing systems and protocols, this assessment aims to identify gaps and areas for improvement and to propose practical recommendations that enhance regional cooperation and ensure the efficient operation of interconnected grids. In particular, the analysis focuses on the following objectives:

- Assess the current state of interoperability among Mediterranean power systems.
- Evaluate the capability of existing communication systems to exchange operational data in near-real-time.
- Identify challenges related to data sharing and propose solutions to facilitate reliable and secure information exchange.
- Formulate recommendations for TSOs based on survey findings and operational needs.
- Determine the minimum set of operational data required to ensure the effective and secure use of interconnections.

To achieve these objectives, two surveys were conducted among Med-TSO members:

- Survey A: Focused on existing SCADA systems in Interconnected Electricity Exchange Zones (IEEZs).
- Survey B: Assessed the preparedness of Med-TSO countries for data exchange.

3.1 Survey participants

The survey on existing SCADA systems received responses from 13 out of 20 Med-TSO members.

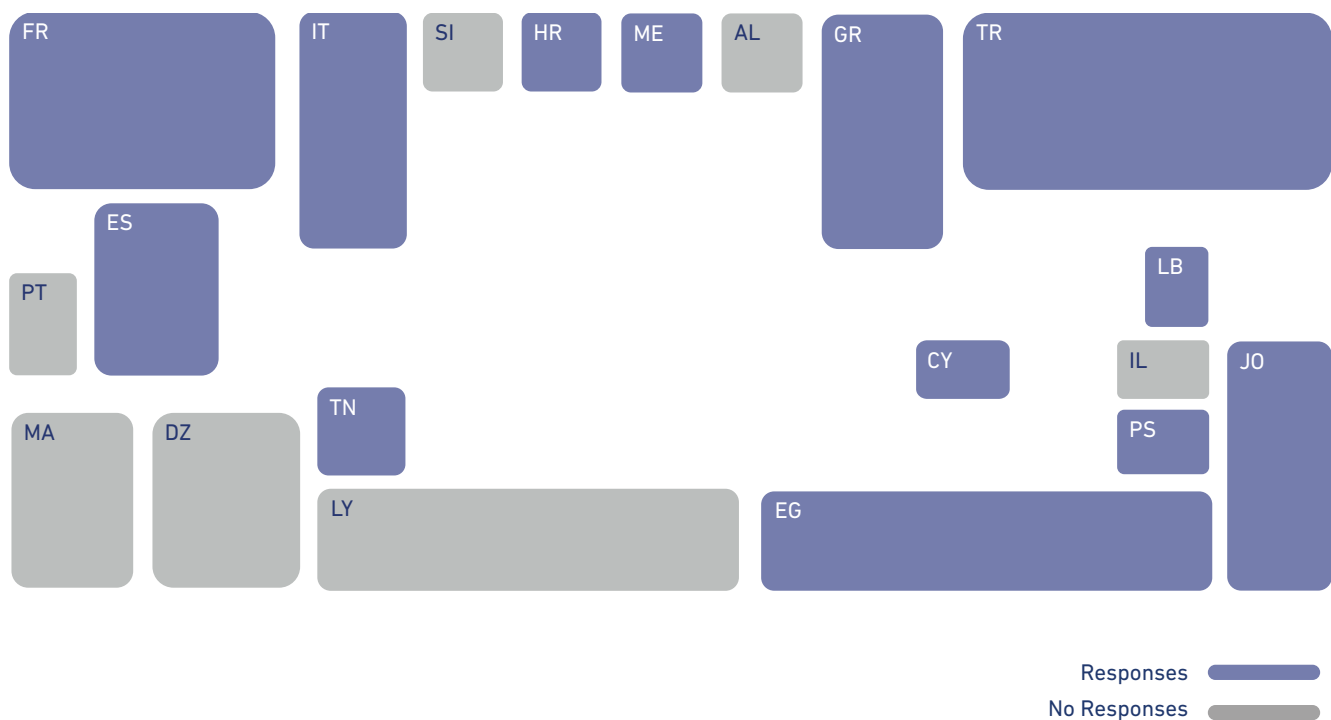


Figure 3.2 Survey participants

This high level of participation provides valuable insight into the current status of SCADA technology across the region. The respondents represent a broad range of utilities, enabling a comprehensive assessment of both the challenges and opportunities related to SCADA implementation.

The following section summarises the countries that participated in the survey and outlines their existing or planned electricity interconnections.

Based on the information collected, several countries across the **North, East, and West Mediterranean** are actively exchanging operational data with neighbouring power systems:

- **North Mediterranean:** France, Spain, Italy, Montenegro, Croatia, Greece, and Türkiye have established data exchange mechanisms in line with ENTSO-E rules to support the efficient operation of interconnected power systems.
- **East Mediterranean:** Egypt and Jordan are actively exchanging data to coordinate grid operations and maintain system stability.
- **West Mediterranean:** Tunisia is currently exchanging basic operational data.
- **Countries with limited or no data exchange:** Cyprus, Lebanon, and Palestine appear to have limited or no operational data exchange, mainly due to geographical constraints or infrastructure limitations.

3.2 Existing SCADA systems

When electricity grids are interconnected across national borders, the seamless exchange of data is essential for efficient operation, reliability, and market integration. Advanced communication technologies continue to play a pivotal role in facilitating these exchanges and bolstering grid performance.

Whilst the majority of interviewed countries (13 out of 20) maintain active data exchange with neighbouring states, Cyprus, Lebanon, and Palestine reported no current exchange activity.

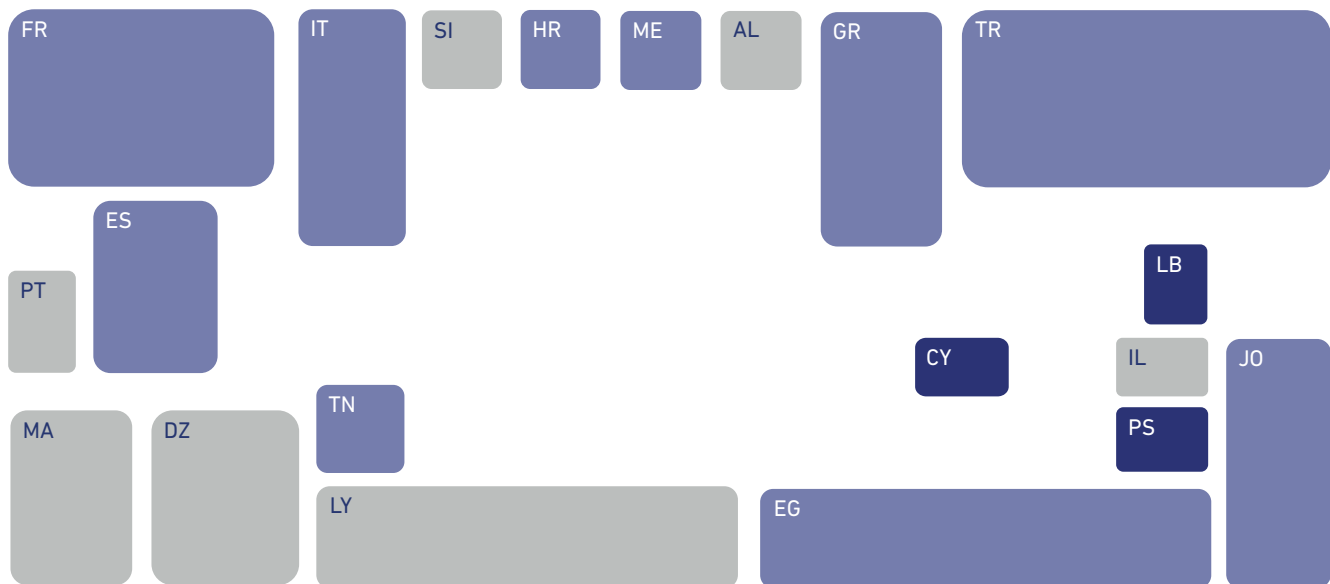


Figure 3.3 Countries committed to data exchange with neighbouring countries

Countries that engage in data exchange with neighbouring countries do so through bilateral rather than lateral data exchange. Other countries implement different arrangements based

on the type of data. The figure below illustrates how each country carries out data exchange, either bilateral or multilateral.

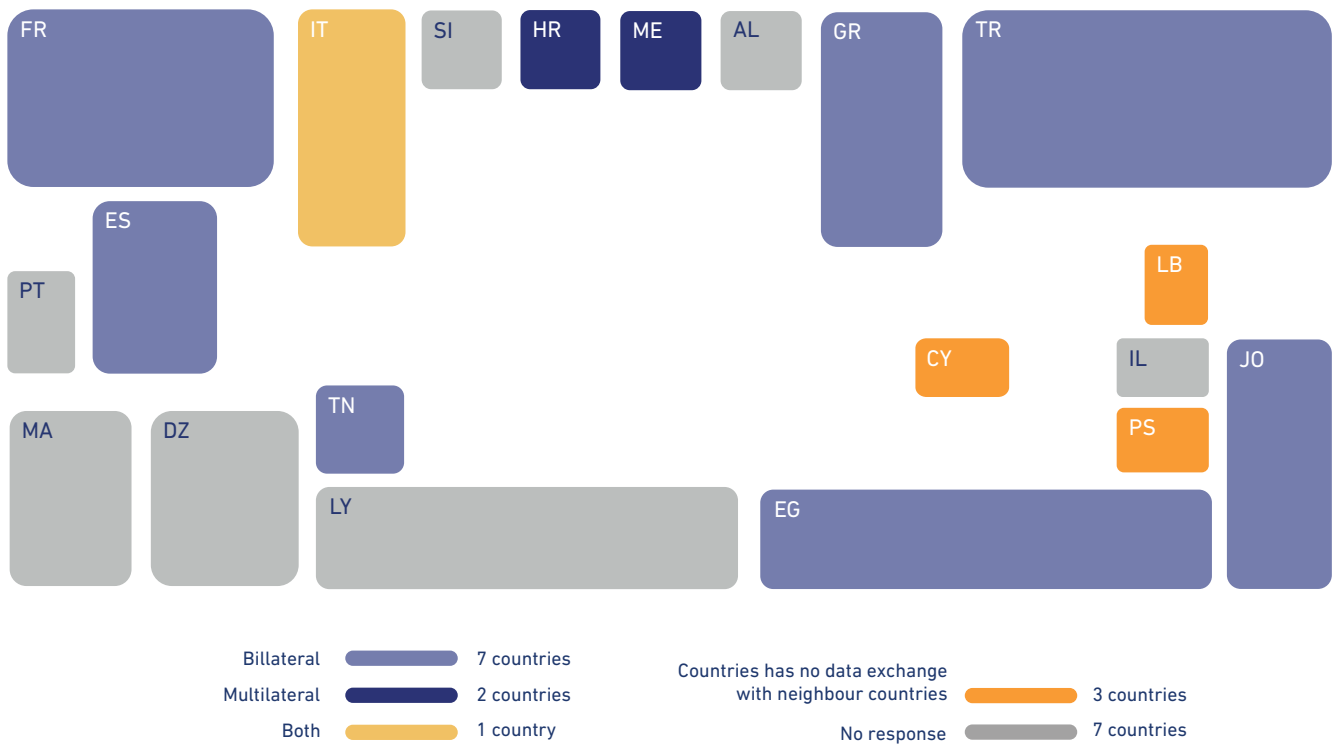


Figure 3.4 Data exchange approach by country

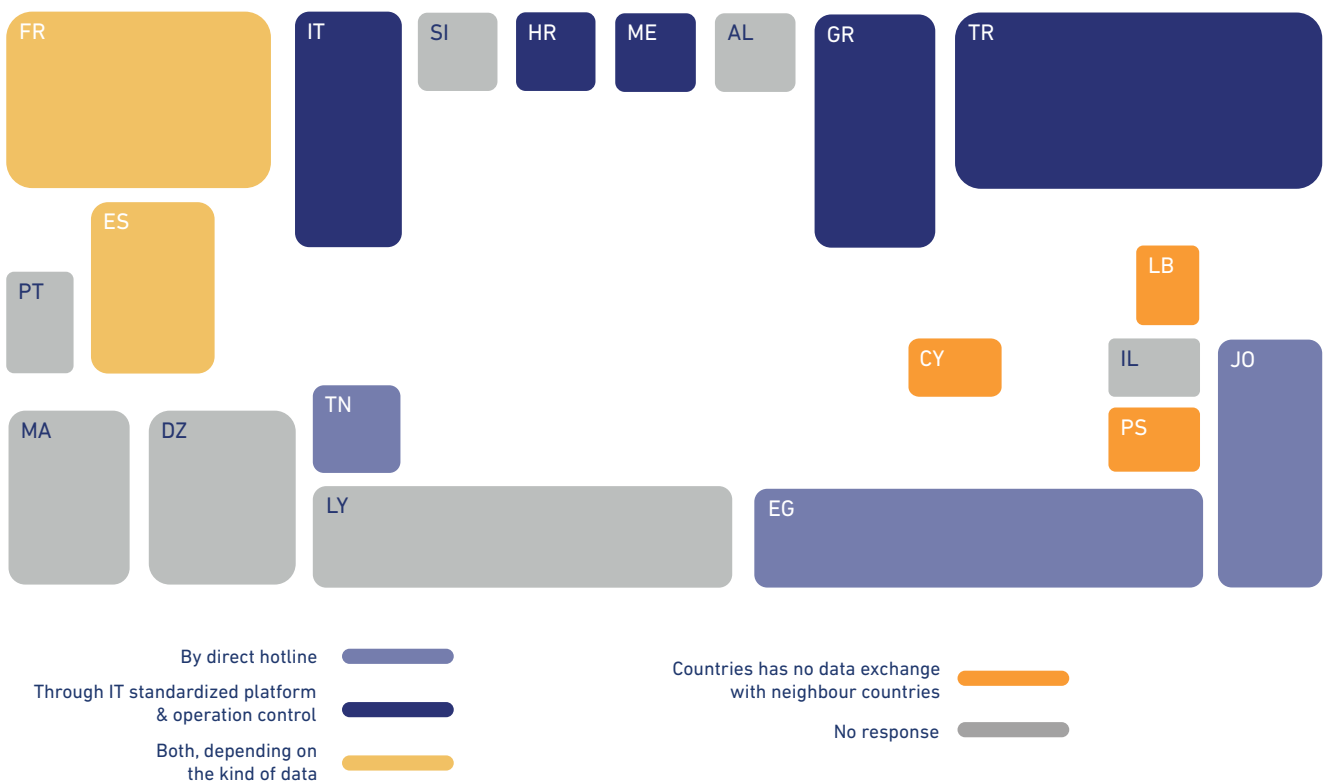


Figure 3.5 Information exchange methods by TSO

The data typically exchanged between interconnected TSOs includes real-time data (SCADA) and operational security data. Whilst this is the standard for the majority of the region, Cyprus, Lebanon, and Palestine currently represent exceptions due to their lack of physical interconnections or operational constraints.

3.3 Categories of data exchanged

When electricity grids are interconnected across national borders, the seamless exchange of data becomes an essential component for ensuring efficient operation, reliability, and successful market integration. Moreover, advanced communication technologies play a pivotal role in facilitating these exchanges and improving grid performance.

Four categories of data are typically exchanged, as described below.

1. Real-time operational data

This category covers essential metrics for immediate grid stability and dispatch:

- System frequency: monitored in real-time (e.g. 50 Hz) to maintain the supply-demand balance and prevent blackouts.
- Power flows: precise measurements at interconnection points for load balancing and congestion management.
- Generator status: real-time output and availability data used for efficient resource dispatch.
- Demand data: regional electricity consumption used for instantaneous load adjustment.

2. Grid operational security data

Information exchanged to safeguard the interconnected system against failures and threats:

- Contingency analysis: shared results on potential faults (e.g. line outages) to coordinate regional responses.
- Cybersecurity: exchange of threat intelligence and mitigation strategies to protect digitalised grid assets.
- Stability and limits: monitoring of voltage stability margins and thermal limits to

prevent cascading failures.

- Fault management: real-time localisation of electrical faults to isolate issues quickly.
- Restoration plans: readiness status of blackstart resources and recovery strategies for post-outage scenarios.

Country	Real-Time Data (SCADA)	Grid Operational Security Data	Long-Term Planning Data	Structural & Forecast data
TUNISIA (STEG)	✓	✓		
EGYPT (EETC)	✓			
JORDAN (NEPCO)	✓	✓		
TURKIYE (TEIAS)	✓	✓		
GREECE (ADMIE)	✓	✓	✓	✓
CROATIA (HOPS)	✓	✓	✓	✓
MONTENEGRO (CGES)	✓	✓	✓	✓
ITALY (TERNA)	✓	✓	✓	✓
SPAIN (REE)	✓	✓	✓	✓
FRANCE (RTE)	✓	✓	✓	✓

Figure 3.6 Operational data exchange by category and country

3. Long-term planning data:

Strategic data supporting infrastructure investment and energy transition over an extended horizon:

- Expansion and capacity: plans for new transmission lines and substations alongside generation capacity forecasts.
- Demand and load projections: long-term estimates based on economic, population, and industrial growth.
- Renewable integration: forecasts of renewable potential and storage requirements to manage intermittency.
- Investment and policy: financial projections and alignment with regulatory changes or carbon reduction targets.

4. Structure and forecast data:

Technical and predictive data used to align short-term operations with grid characteristics:

- Supply and demand forecasts: predictions based on weather patterns, fuel availability, and economic trends to balance the grid.
- Grid structure: detailed mapping of the physical network (substations, transformers, and lines) to assess transfer capacities.
- Generation patterns: analysis of historical load profiles to improve the accuracy of future scheduling and resource allocation.

The following summary details the categories of data shared among participating countries, based on the survey results.

Country	The maximum and minimum active and reactive power of Power Generating Modules (SCADA)	Technical data on phase-shifting transformers	Technical data on HVDC Systems	Power-Generating Modules data	Technical data on reactors, capacitors, static volt-ampere reactive (VAR) compensators	Operational security limits defined by each TSO for relevant/critical network elements	Protection set points of the lines for which the contingencies are included as external contingencies in their contingency lists.
TUNISIA (STEG)	✓			✓		✓	✓
EGYPT (EETC)	✓			✓	✓	✓	✓
JORDAN (NEPCO)	✓			✓	✓	✓	✓
TURKIYE (TEIAS)			✓			✓	✓
GREECE (ADMIE)	✓	✓	✓	✓	✓	✓	✓
CROATIA (HOPS)				✓			✓
MONTENEGRO (CGES)	✓		✓	✓		✓	✓
ITALY (TERNA)	✓	✓	✓	✓	✓	✓	✓
SPAIN (REE)	✓	✓	✓	✓	✓	✓	✓
FRANCE (RTE)	✓	✓	✓	✓	✓	✓	✓

- Data is shared
- Data is not available for sharing because they are outside the agreements
- Data no collected

The analysis reveals a significant disparity in the availability and exchange of operational data among Mediterranean TSOs. Whilst several TSOs provide comprehensive datasets, including generation limits, reactive power capabilities, and operational security criteria, others exchange only a limited subset of this information. This lack of uniformity remains a primary constraint for advanced regional coordination.

TSOs that are members of both Med-TSO and ENTSO-E (notably RTE, REE, TERNA, CGES,

HOPS, IPTO and TEIAS) demonstrate near-full availability of all assessed data categories, including:

- Maximum/minimum active and reactive power limits for generating modules.
- Technical data for phase-shifting transformers and HVDC systems.
- Characteristics of reactive power compensation devices.
- Clearly defined operational security criteria and contingency definitions.

This reflects a high degree of alignment with current ENTSO-E network codes. Whilst non-EU Mediterranean TSOs generally provide core operational data, the exchange of detailed technical modelling data for interconnections remains incomplete. These data gaps are critical to address, as they are essential for the implementation of advanced capacity calculation methodologies and regional adequacy assessments.

3.4 Technical and organisational intervals of data exchange

The frequency of data exchange between neighbouring power systems is essential for ensuring the efficient and reliable operation of interconnected grids. It determines how quickly operators can share information, coordinate actions, and respond to system events.

Data exchange intervals depend mainly on the **type of data, grid complexity, communication infrastructure, and regulatory requirements**. The survey results in Figure 3.7 indicate that real-time operational data exchange is well established among most interconnected Med-TSO members, particularly for data categories critical to system security and real-time operation. Measured active power interchanges, aggregated generation infeed, operating conditions, and planned outages are the most consistently exchanged data types, especially among EU and EU-connected TSOs, reflecting alignment with ENTSO-E operational practices.

Country	Frequency deviation: area Control error; (generating modules stability factors)	Measured active power interchanges between countries/synchronous areas/load frequency control/automatic generation control	Aggregated generation in feed exchange	Consumption data exchange	Planned outages and substation topologies	Operating condition exchange	Black start capability units and components
TUNISIA (STEG)		✓	✓		✓	✓	
EGYPT (EETC)		✓	✓			✓	
JORDAN (NEPCO)		✓	✓		✓	✓	
TURKIYE (TEIAS)	✓	✓			✓	✓	
GREECE (ADMIE)	✓	✓	✓	✓	✓	✓	
CROATIA (HOPS)	✓	✓	✓	✓	✓		
MONTENEGRO (CGES)	✓	✓	✓	✓	✓	✓	
ITALY (TERNA)	✓	✓	✓	✓	✓	✓	
SPAIN (REE)	✓	✓	✓	✓	✓	✓	
FRANCE (RTE)	✓	✓	✓	✓	✓	✓	

Daily
 Weekly
 Real-Time
 Data no shared

Figure 3.7 Interval of data exchange between interconnected zones

In contrast, consumption data and black-start capability information are exchanged less systematically across the region, suggesting technical, regulatory, or confidentiality constraints. Non-EU Mediterranean TSOs generally exchange core operational data but share fewer detailed datasets compared to EU Mediterranean TSOs.

Overall, the frequency and scope of data exchange are broadly adequate for current operational needs, supporting effective coordination and system stability, while targeted expansion of selected data categories could further enhance regional operational resilience.

3.5 Preparedness of Med-TSO countries for operational data exchange

Exchanging operational data between countries is a complex undertaking, requiring a high degree of standardisation, compatibility and trust. This is particularly challenging in a region as diverse as the Mediterranean, with its varying regulatory frameworks, technical standards, and levels of digital infrastructure.

The key benefits of operational data exchange are:

1. Improved grid stability and security.
2. Enhanced market efficiency and competition.

3. Facilitated cross-border electricity trade.

4. Accelerated integration of renewable energy sources.

Figure 3.8 illustrates the current level of preparedness of Med-TSO countries for operational

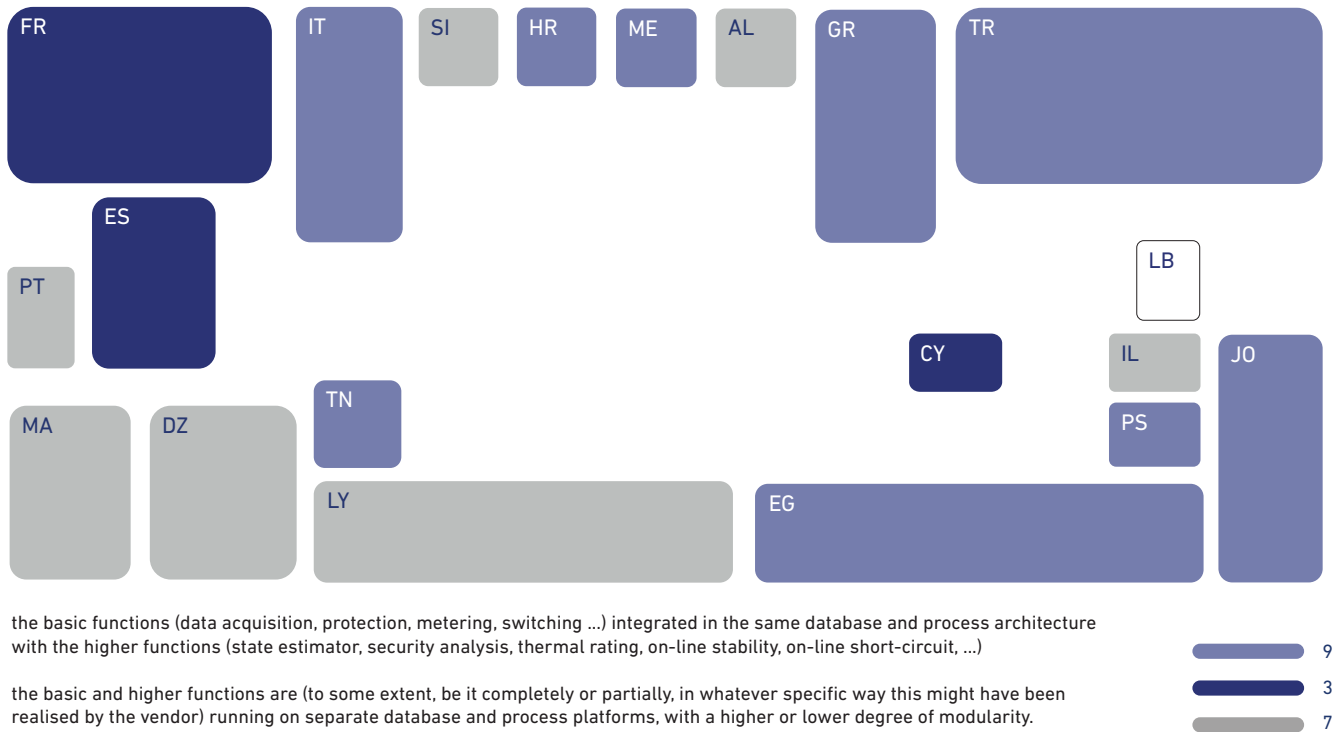


Figure 3.8 Med-TSO countries' readiness for operational data exchange

One group of countries shows high readiness, where both basic operational functions (such as data acquisition, protection, metering, and switching) and higher-level functions (including state estimation, security analysis, thermal rating, online stability, and online short-circuit analysis) are integrated within a single database and process architecture. These countries are well positioned to support advanced operational coordination and real-time data exchange.

A second group demonstrates partial or intermediate readiness, where basic and higher-level functions are implemented but run on separate databases and process platforms, with varying degrees of modularity depending on vendor solutions. Whilst these systems enable operational functionality, the lack of full integration may limit efficiency, scalability, and seamless cross-border data exchange.

3.6 Data access permissions and cybersecurity

As SCADA systems become more interconnected, safeguarding them against unauthorised access is critical for grid resilience. The following strategies represent the regional benchmark for securing SCADA environments:

Data access management:

- Role-based access control (RBAC): access rights are strictly aligned with organisational roles; for example, system administrators maintain full oversight, while operators are granted limited access specific to their functional requirements.
- Principle of least privilege: users are granted only the minimum permission necessary to perform their duties, significantly reducing the potential "attack surface" during a security breach.
- Separation of duties: critical operations are distributed among multiple individuals to prevent any single user from exerting total control over sensitive system functions.
- Access logging and auditing: comprehensive activity logs enable the continuous monitoring of unusual behaviour, with regular audits serving as a proactive defence mechanism.

Cybersecurity best practices

- Policy development: tailored security protocols that address the unique vulnerabilities of high-voltage SCADA environments.
- Security awareness: continuous training programmes to ensure personnel are the first line of defence against social engineering and cyber threats.
- Incident response: regularly tested protocols designed to ensure rapid recovery and containment in the event of a system compromise.

The survey results indicate that Med-TSO members apply a range of cybersecurity measures to protect exchanged operational data, with practices varying in maturity and detail. Most TSOs rely on technical controls, such as firewalls, dedicated communication links, network segregation between SCADA and corporate networks, access control, and continuous network monitoring.

Several TSOs complement technical measures with organisational and contractual safeguards, including restrictive data-sharing agreements, role-based access limitations, and regular staff awareness and risk communication.

European TSOs generally report more structured and layered cybersecurity approaches, including the use of proprietary or private networks (e.g. ENTSO-E communication infrastructures) and security frameworks aligned with overall EMS protection. In contrast, some

non-EU TSOs report basic but essential protections, such as firewalls and access restrictions, with limited additional detail provided.

Overall, whilst baseline cybersecurity measures are widely in place, the level of standardisation, transparency, and depth of implementation varies across the region, highlighting opportunities for further harmonisation and knowledge sharing among Med-TSO members.

3.7 Future plans and initiatives

The survey responses indicate that several Med-TSO members are planning to enhance and expand cross-border operational data exchange in the coming years. These initiatives are primarily driven by the need to improve system security, operational coordination, and preparedness for increasingly complex grid conditions.

Planned actions include upgrades to SCADA and Energy Management Systems (EMS) to enable higher data availability, improved interoperability, and more reliable real-time information exchange with neighbouring systems. Some TSOs also foresee the adoption of more standardised communication protocols and IT platforms, facilitating smoother integration with regional and international data exchange frameworks.

Furthermore, a number of respondents highlighted intentions to strengthen cybersecurity and data governance arrangements, including clearer data access rules, enhanced network segregation, and alignment with recognized international security practices. These measures aim to support the secure expansion of data exchange whilst addressing confidentiality and data protection concerns.

Overall, the planned initiatives reflect a shared recognition among Med-TSO members of the importance of progressively increasing the scope, quality, and security of operational data exchange, whilst ensuring consistency with national regulations and regional coordination requirements. These and other regional projects are mapped in Figure 3.9.

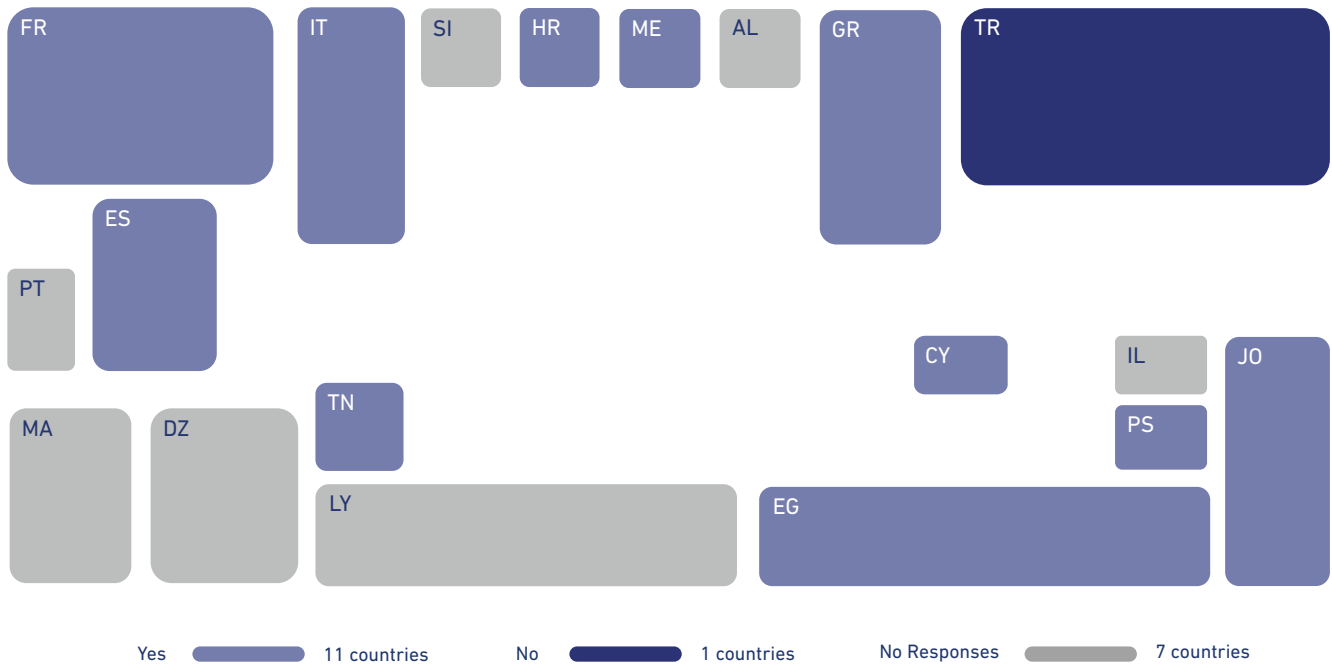


Figure 3.9 Countries with initiatives to improve or expand data exchange

3.8 Case analysis: Lebanon, Palestine, and Cyprus

Full data transparency is a prerequisite for maximising the technical and economic benefits of cross-border interconnections. The following cases highlight specific challenges that currently limit exchange in certain areas:

Cyprus – geographical isolation

As an island system, Cyprus has historically been isolated from the Mediterranean mainland. Whilst this has physically prevented real-time data exchange, the situation is currently being addressed through the Great Sea Interconnector project. Current limitations reflect infrastructure that is in the implementation phase, rather than a lack of strategic commitment.

Lebanon and Palestine – infrastructural and geopolitical challenges

Limited data exchange in these countries' results from regional instability, outdated grid infrastructure lacking digital maturity, and economic constraints that delay investment in modern, standardised IT platforms.

4

Part II – Rules and Protocols for Increased Coordination of Power Systems Approach to Benchmarking

Benchmarking is a strategy tool used to compare the performance of business processes and products with the best performances of other companies inside and outside the industry.

Performance and quality of processes can be judged in several ways, for example, by comparing against other internal processes, owned by different units, or against past data. However, such measurements offer limited insights and may be biased by the and the references can be affected by the very same flaws that affect the objective of the comparison.

Comparisons with external organisations, by contrast, can highlight best industry practices and promote their adoption. This kind of comparison is commonly applied in benchmarking. Several benchmarking methods exist (Figure 4.1) and one can either select a specific method suited to their needs or combine methods to achieve the best results.

4 Libya was missing from the mid-term data collection (2027 & 2030) due to limited engagement from the Libyan side.

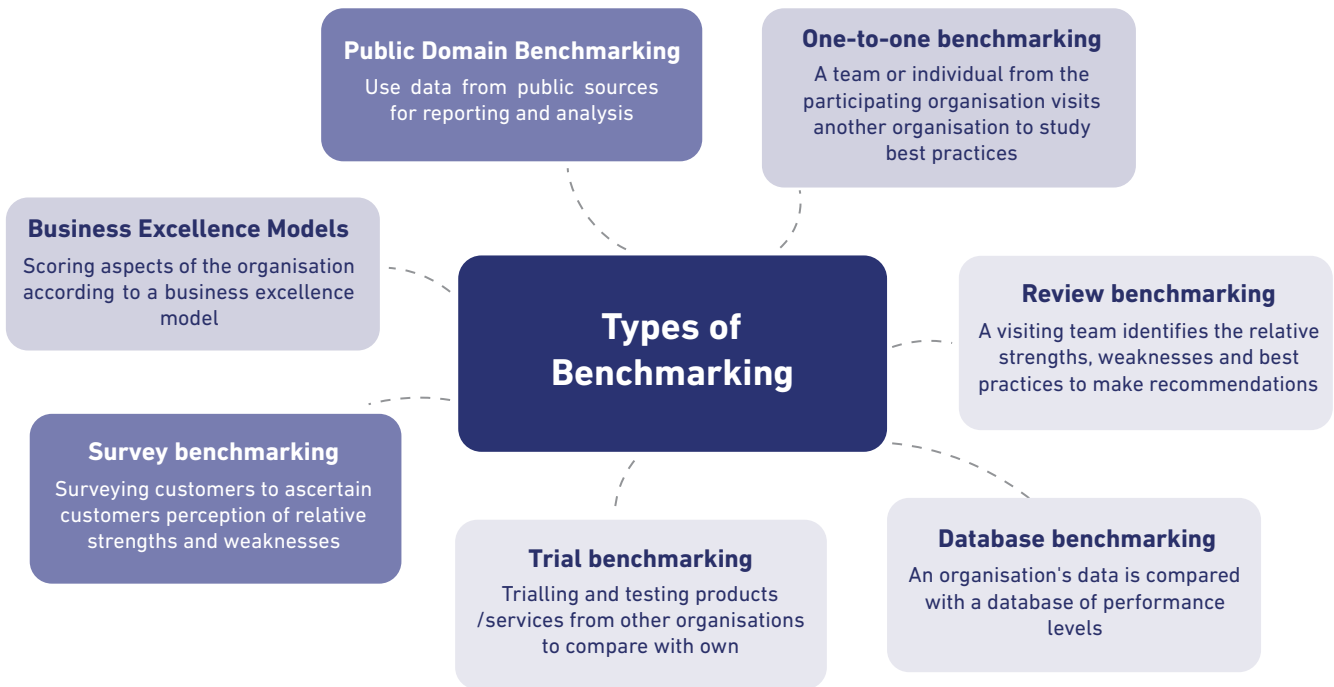


Figure 4.1 Types of benchmarking [1]

For this assignment, the following techniques were selected as the most appropriate for the purpose of data collection:

1. Survey Benchmarking (SB) – this was the primary source of insights from the targeted operators. SB was identified as the most suitable approach because surveys are commonly used to quantify end-users' and/or consumers' perceptions. With the objective of summarising best practices across different dimensions, such as geographical scope, timeframe, data exchange, and transparency, this benchmark was deemed most appropriate for grouping and summarising the collected information.

2. Public Domain Benchmarking (PDB) – this approach, which focuses on outputs only without requiring data manipulation, was applied to identify coordination initiatives already implemented and documented by member states or international system operators or entities. A simplified PDB approach was set up as a backup data collection strategy to bring in information from TSOs outside ENTSO-E and the Mediterranean area, in case the outcome of primary data collection (SB) proved unsatisfactory and to extend the benchmarking coverage.

Answers are collected from member TSOs and the first aggregations were made, the practices collected were compared with external sources (e.g. EU regulations) or among each other by applying the following approaches:

3. Business Excellence Models (BEM) – commonly represented by a set of interrelated

criteria that captures key aspects of a successful organisation or process implementation, this approach was adopted to compare single answers as well as aggregated SB results with EU regulation, which served as a reference within the project. The BEM approach is applied using international standards and/or best practices, like EU regulation and/or ENTSO-E System Operation Guidelines (SOGL), as an excellence model. The SB results were scanned for the same key successful factors identified in these excellence models.

4. One-to-one (O2O) – this approach requires the leading organisation or process to be identified first, after which the best practice can be adopted and a roadmap for implementation created. A wide-scale application of this approach was not foreseen for this assignment, given the objective of harmonising existing procedures and proposing a model suited to all Med-TSO members. Nevertheless, O2O was selected as a potential means of identifying the practices, or individual tasks, to be included in the target model, should a highly effective coordination process emerge from the survey data collection or regulation assessment.

The four benchmarking strategies and tools above are combined into the structured approach shown in Figure 4.2. The primary sources of data and information for the design of the Med-TSO coordination target model are the members themselves, who provide information by answering a survey covering the processes followed in outage coordination and capacity calculation with neighbouring countries, regardless of whether those are members of Med-TSO. As mentioned, a second source of input is the public domain benchmarking, carried out for the specific purpose of integrating survey data collection with any details on the coordination procedures that Med-TSO members have already shared on their public websites.

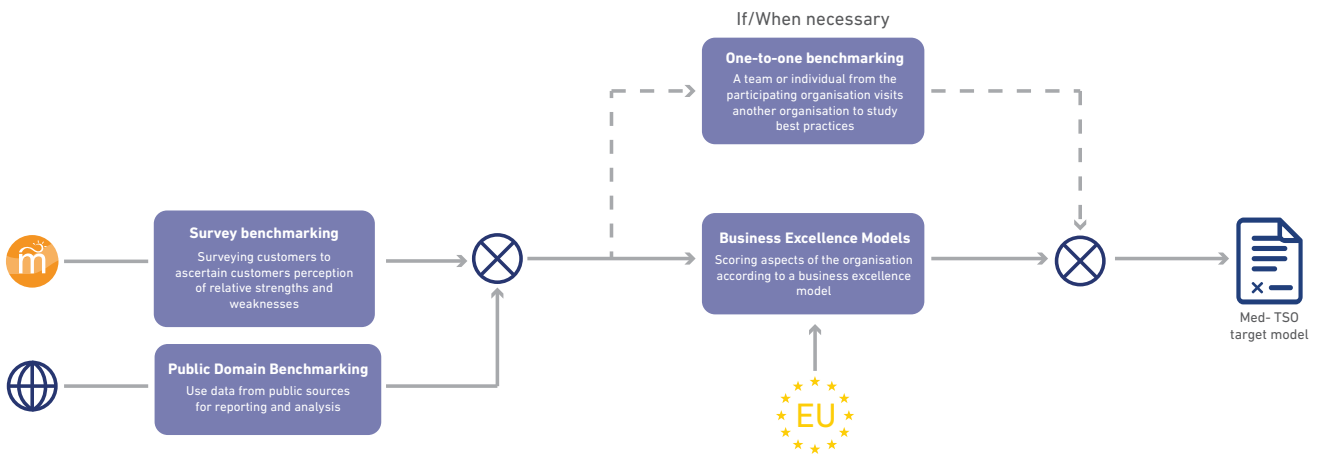


Figure 4.2 Overview of the survey, benchmarking and target model design

Following the SB and PDB, the collected information is merged and aggregated according to relevant dimensions, such as geographical location or membership into international organizations (see Figure 14.1) to highlight common practices and possible correlations, for example, common practices between members of both Med-TSO and ENTSO-E.

The process of merging and aggregating information collected from Med-TSO members and potential external TSOs allows a first draft target model to be defined, which is then refined by comparing identified best practices with ENTSO-E guidelines through the BEM approach. The comparison with European guidelines enhances the efficiency of the coordination models by leveraging the long-term experience acquired within the ENTSO-E interconnected grid.

5

Coordination Model and Goals

Survey data provided a comprehensive overview of the current coordination practices followed by Med-TSO members. A broader analysis of responses [8] [9] confirms that:

- I. European TSOs generally follow ENTSO-E coordination procedures for both outage coordination and capacity calculation (when this task is not outsourced to Regional Coordination Centres)
- II. Some North African and Middle Eastern member states have established bilateral coordination procedures, at varying degrees of complexity.

To define an effective coordination model for all Med-TSO members, the general findings of the data collection can be summarised into three maturity levels depicted in Figure 5.1.

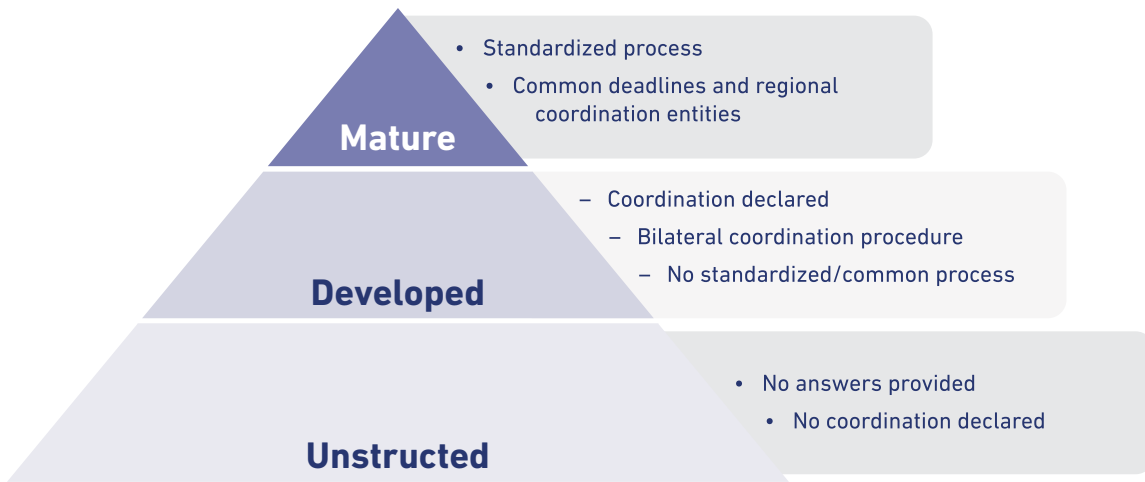


Figure 5.1 Coordination maturity levels among member states

These maturity levels do not represent an assessment of any individual member's capabilities, nor do they express any judgement on the coordination process applied; they simply relate the position of each member relative to the responses provided by the others.

Given that 35% to 40% of the survey recipients did not file any answer, the figures emerging from the collected data suggest most of the members have developed coordination processes of some sort, even if only ENTSO-E members and observers follow standardised processes and apply common procedures.

Nevertheless, the overall picture emerging from the survey demonstrates that **developed and mature members are at or beyond** the coordination standard set by the template business processes introduced in Chapter 13 (see Figure 13.1 and Figure 13.2). On the other hand, **unstructured Members** – using the classification used here – **are several steps away from implementing the recommended coordination process** (Figure 5.2).

The Med-TSO association as a whole can be classified as a **developed** organisation, comprising of a significant number of mature Members (ENTSO-E members and observers), but hindered held back by the “unstructured” countries that, according to the data, do not appear to even coordinate with bordering TSOs.



Figure 5.2 Development process to fully implement the recommended business processes

According to the situation described above, the following ground rules for the development of the coordination framework can be stated. The coordination model should offer:

- **Technically sound advantages** to justify adopting the model recommended here.
- A **practical implementation path for unstructured** members, who do not yet apply common procedures.
- A **reasonable implementation for developed and mature** members, avoiding confusion, duplication or replacement of procedures they are currently following.
- A Minimum Value Proposition sufficient to ensure that all members can be considered “developed” on the maturity scale before taking any further action.

5.1 Coordination advantages and goals

Establishing a coordination model within Med-TSO will require a significant shared effort among member states, however it can lead to many advantages [6], including:

- Increased efficiency in system operation
 - Maximised availability of generating units in the event of mutual support being required.
 - Maximised interconnection reliability (due to outage coordination concerning the interconnections).
 - Improvement of security and adequacy of the interconnected power system.
 - Minimised risk of wide area events, such as brownouts or blackouts.
 - Lower costs through maximisation of the availability of transmission capacity.
- More comprehensive and forward-looking grid planning
- Support for the energy transition
 - Transparent and effective access to transmission networks, boosting the integration of renewable energy.

International experience confirms that the larger the effort, the longer the implementation roadmap. Accordingly, the coordination model presented in this report aims to minimise the overall implementation effort for Med-TSO members, reflecting the different circumstances of each member state identified in the survey results. The final goal is to progress towards harmonisation of normal and emergency operations of power systems across Med-TSO

member states.

Chapters 8 and 9 present the coordination procedures (outage planning and capacity calculation) constituting the Minimum Value Proposition for increased coordination of Mediterranean power systems. Further developments in these procedures are also reported, to provide a complete overview of what can be implemented in the short term and what should be implemented in future phases to improve the overall coordination between Med-TSO members. As the initial step of coordination is the definition of a Common Grid Model, a third coordination procedure aimed at defining the CGM for Med-TSO Members is also presented as part of this MVP (see Chapter 7).

5.2 Coordination implementation: general models

As noted, the designed coordination models are presented with an implementation consisting of multiple phases, starting from phase 0 (MVP) through to the more complex phase 2.

Before detailing the coordination models at different implementation phases, a general overview is presented. It is important to note that some definitions change meaning depending on the implementation phase in question.

Figure 5.3 shows the general workflow for the construction of a CGM. As a first step, it is necessary to define the configurations of the system (scenarios) to be considered for the collection of the IGMs. The involved TSOs then prepare their IGMs according to the agreed scenarios. The CGM will then be created by merging the collected IGMs and approved by the involved TSOs, before being used for the coordination process (capacity calculation and outage planning).

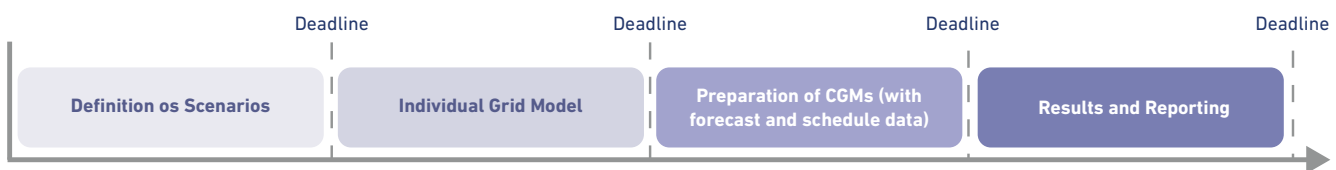


Figure 5.3 Common grid model—general model

Figure 5.4 shows the general workflow for the coordinated capacity process. Following the creation of IGMs and the collection of required documents², an assessment is carried out and the results are approved by the involved TSOs.

² Refer to section [Capacity Calculation - Phase 1](#) for the list of required documents.

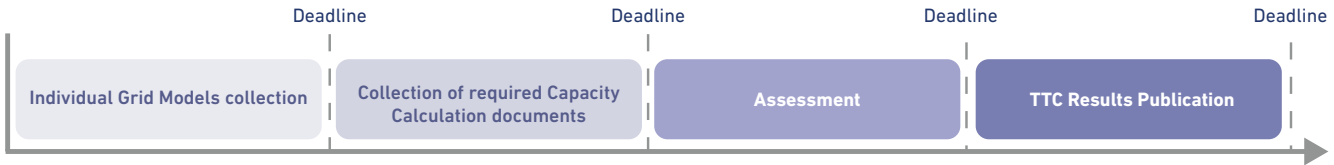


Figure 5.4 Coordinated capacity calculation – general model

Figure 5.5 shows the general workflow concerning the coordinated outage planning process. Following the creation of IGMs and the collection of outage plans from each involved TSO, an assessment is carried out, considering the relevant assets list approved by the involved TSOs. Based on the assessment, a final outage plan is created and approved by the involved TSOs.

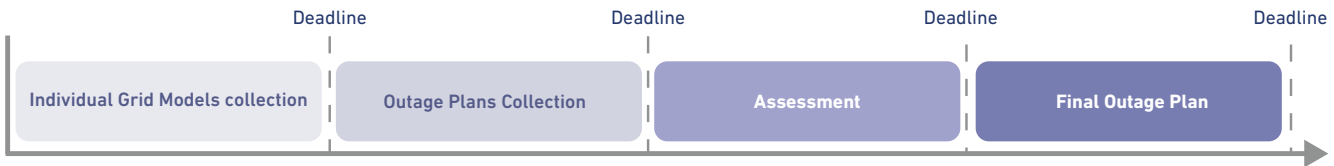


Figure 5.5 Coordinated outage planning –general model

5.3 Implementation roadmap

The implementation of the coordinated outage planning and coordinated capacity calculation models is designed as a step-by-step process consisting of three phases (Figure 5.6):

- **Phase 0** represents the MVP and aims to contain complexity. In this phase, the coordination remains the responsibility of the TSOs themselves (bilateral coordination) with no third party coordinators yet involved. The data exchanged to create a CGM is limited to network topology data only. No power flow models are shared at this stage, coordinated outage planning and coordinated capacity calculation are based on qualitative assessments. The key limitation of phase 0 is the lack of power flow-based assessments.
- **Phase 1** marks the transition from qualitative to quantitative assessments, based on power flow models. At this stage, the shared data for constructing the CGM consists of a simplified power flow model (e.g. an equivalent circuit representing the entire network of a TSO). Coordination remains the responsibility of the TSOs themselves (bilateral coordination), as in Phase 0.
- **Phase 2** brings the major coordination upgrade, moving from bilateral to regional coordination. In this phase, the shared data for the construction of the CGM consists of a power flow model, sufficiently detailed to support assessments for the definition

of coordinated regions. A Coordination Entity shall be established and entrusted to manage the coordinated processes between the TSOs within the coordinated regions. The responsibility for identifying the Coordination Entity lies with Med-TSO Members; however, the Technical Committee Operation may provide guidelines for entrusting the coordination role (duration, capabilities, rotation, duties, etc.). The improved CGM increases the accuracy of the assessments (for outage planning and capacity calculation), improving the coordination overall.

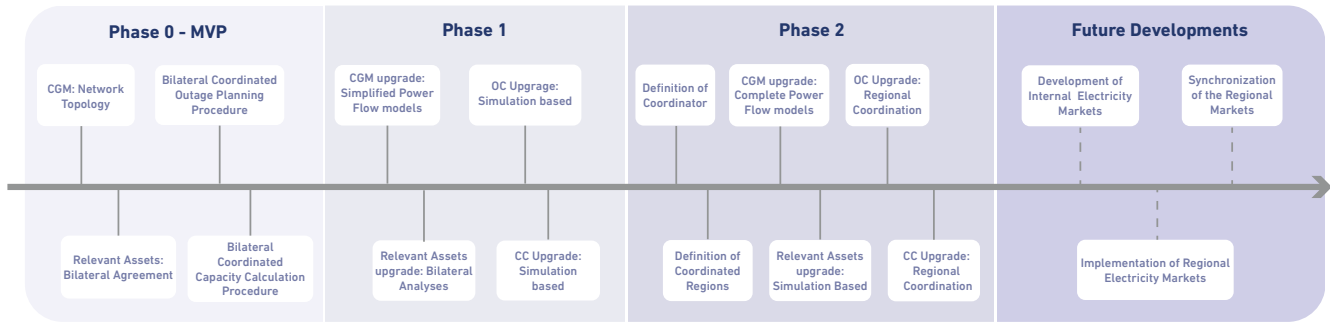


Figure 5.6 Implementation roadmap

The phased implementation of the general models introduced in the previous chapter is intended to establish an iterative process that will increase the maturity of members from unstructured to fully mature (Figure 5.2). Throughout this iterative process, each block and some definitions included in the general coordination workflows will evolve to reflect the transition towards greater maturity. Table 5.1 outlines the definitions that change across the implementation phases described above.

Phase	0 (MVP)	1	2
Scenario	Possible topology configurations of the system.	Possible configurations of the system (topology and load/generation profile).	Possible configurations of the system (topology and load/generation profile).
IGM3	Topology data of the network of a single TSO.	Simplified power flow model of the network (e.g. equivalent circuit) of a single TSO.	Power flow model of the network of a single TSO.
CGM	Topology data of the networks of more TSOs, created by merging IGMs. (Topology Only)	Topology data of the networks of more TSOs, created by merging IGMs. (Simplified power flow model)	Topology data of the networks of more TSOs, created by merging IGMs. (Detailed power flow model)
Assessment	Qualitative Assessment	Quantitative Assessment (simplified)	Quantitative Assessment

Table 5.1 Definitions across implementation phases

Further advances could include the development of an internal electricity market for each Med-TSO member, followed by the development of regional electricity markets and, finally, by the alignment of these regional markets.

³ Refer to the [Common Grid Model](#) for a detailed description of the model creation workflow.

6

Common Grid Model

Each member state shall prepare its own individual grid model as a starting point for the creation of a Common Grid Model, using a common data format previously defined by the Technical Committee Operation.

Figures 6.1 and 6.2 show the survey results on data formats currently in use. The number of member states using each data format is shown. Based on the surveys, no single data format commands a clear majority. For this reason, Technical Committee Operation shall support members in defining a standard data format for IGM data sharing, as well as a standard communication protocol.

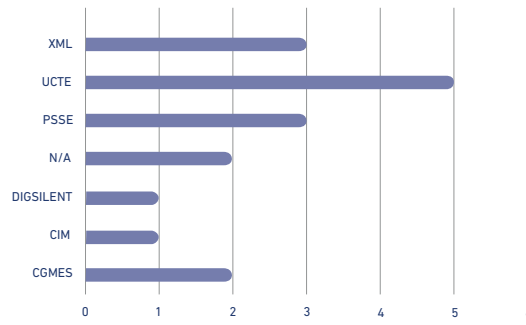


Figure 6.1 Outage planning survey – data format

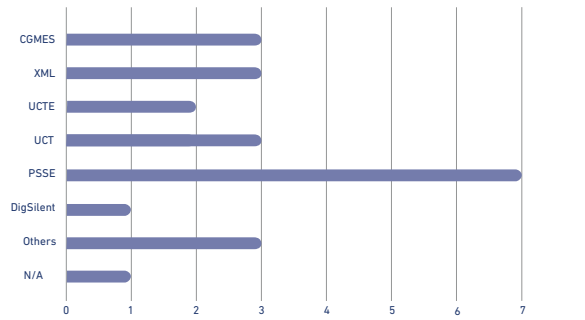


Figure 6.2 Capacity calculation survey – data format

Several options are available for exchanging individual grid models. Nevertheless, the selection should be driven by minimisation of the adoption effort for all members. International experience suggests that the options listed in the table below might be most effective for the Med-TSO case.

Format	Adopted by	1	2
Market vendor's (e.g. Siemens PSSE/E)	GCCIA, WAPP	<ul style="list-style-type: none"> Large user base Already adopted by many Members 	<ul style="list-style-type: none"> Subject to vendor's modifications Difficult customization and adaptation to need
CIM/CGMES	ENTSO-E	<ul style="list-style-type: none"> Fully independent data format Already adopted by many Members 	<ul style="list-style-type: none"> Complex, detailed format Customizable according to needs (Profiles) Longer adoption

The Technical Committee Operation may propose that one or more member states with previous experience in the creation of an individual grid mode mentors other member states in finalising this task.

The Technical Committee Operation shall establish procedures with the details concerning the CGM updates, methodologies and their frequency (e.g. yearly, monthly, weekly, daily) and submit them to each member state for approval.

6.1 CGM – Phase 0 (MPV)

The following flowchart (Figure 6.3) shows the proposed process for creating a Common Grid Model in phase 0 (MVP), along with recommended deadlines for the required activities. Coordination at this phase consists of bilateral agreements between TSOs, with shared network data limited to topology.

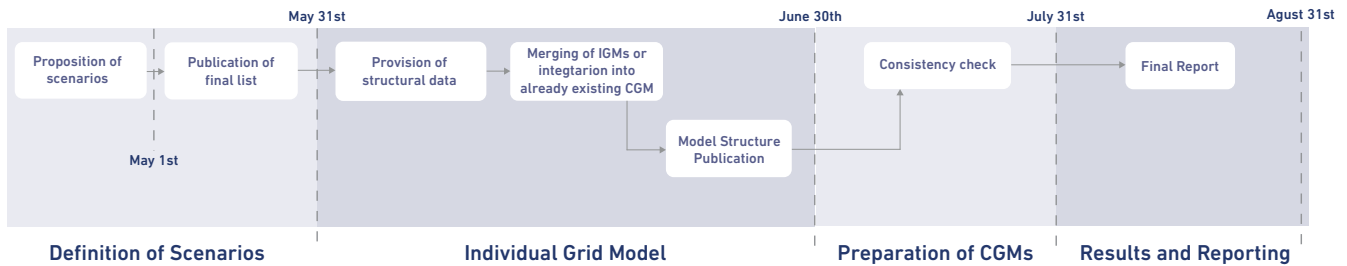


Figure 6.3 CGM – phase 0 (MVP)

The TSOs involved in the bilateral coordination shall first define the number of CGM scenarios to be prepared. In phase 0, the scenarios represent the possible topology configurations of the systems. The objective is to identify the minimum number of scenarios needed to represent the different situations likely to be encountered.

Once all scenarios are agreed upon the common list for the following year shall be published, including a description and the period during which they are to be used. The CGM will be prepared based on this list.

From June, TSOs share their IGMs with neighbouring TSOs, based on the previously defined list of scenarios. In phase 0, IGMs consist of network topologies only.

A Common Grid Model shall be created based on shared IGMs and, upon completion, approved by both TSOs involved (bilateral agreement).

6.2 CGM – Phase 1

The flowchart in Figure 9.4 shows the proposed process for creating a Common Grid Model in phase 1, along with recommended deadlines for the required activities. Coordination at this phase still consists of bilateral agreements between TSOs but, unlike phase 0 (MVP), shared network data are simplified power flow models.

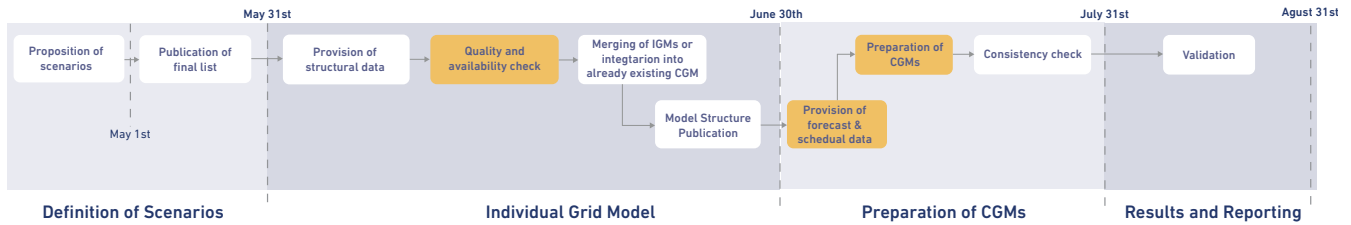


Figure 6.4 CGM model – phase 1

The TSOs involved in the bilateral coordination shall first define the number of CGM scenarios to be prepared. In phase 1, scenarios represent the possible configurations of the system (e.g. peak and off-peak scenarios). The objective is to identify the minimum number of scenarios needed to provide an accurate representation of the different situations likely to be encountered, in terms of topology and generation/load profiles.

Once scenarios are agreed, the common list of scenarios for the following year shall be published, including a description of those scenarios and the periods during which they are to be used. The CGM will be prepared based on this list.

From June, the TSOs share their IGMs with neighbouring TSOs, based on the agreed list of scenarios. In Phase 1, the IGMs are simplified power flow models (e.g. an equivalent circuit to represent the entire network of a TSO). The degree of details, format and communication protocol to share the simplified power flow models shall be established by bilateral agreement between the involved TSOs. Each involved TSO shall merge the collected information from neighbouring TSOs with its own grid model. At this phase, forecast and schedule data are implicitly included in the shared simplified power flow models.

Before the end of July, the TSOs shall perform a consistency check on data received from neighbouring TSOs and, before the end of August, validate the CGMs.

6.3 CGM – Phase 2

The following flowchart (Figure 6.5) shows the proposed process for the creation of a Common Grid Model in phase 2, along with recommended deadlines for the required activities. Coordination at this phase is no longer restricted to bilateral agreements only (as in phase 1). Coordinated regions shall be defined and, for each, the Coordination Entity shall be entrusted to perform coordination activities. Shared network data are detailed power flow models.

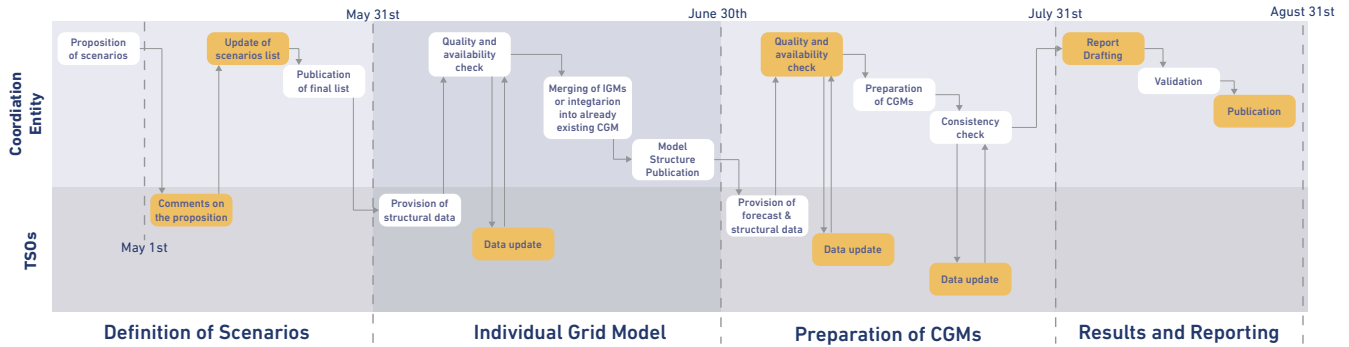


Figure 6.5 CGM model – phase 2

The Coordination Entity shall first propose the number of CGM scenarios to be prepared. The objective is to identify the minimum number of scenarios needed to accurately represent the different situations likely to be encountered. The proposed number of scenarios shall be submitted to all TSOs for their review and comments.

Based on their own knowledge, TSOs shall review the proposed scenarios and inform the Coordination Entity whenever they would like to add additional scenarios or if they suggest modifications of proposed scenarios.

The Coordination Entity shall analyse the TSOs' comments and act on them according to their relevance. Where necessary, the proposed scenarios shall be updated and additional scenarios proposed, taking into account the needs of the TSOs.

Once all scenarios are agreed, the Coordination Entity shall publish, every year, the common list of scenarios established for the following year, including a description of those scenarios and the period during which they are to be used. The CGMs will be prepared based on this list.

From June, the TSOs prepare and send to the Coordination Entity up-to-date structural data for their power systems, including the detailed technical parameters of all assets (such as generation units, transmission lines, transformers, substations, reactors/capacitors, dynamic models and parameters for creating the dynamic CGM models).

The TSOs shall ensure that:

- All information already provided to the Coordination Entity remains valid.
- All assets that were part of the power system during year Y-1 will still be in operation in year Y.
- All relevant assets to be commissioned during year Y are described.

Regarding the assets that are to be commissioned, modified, or decommissioned during the following year, retaining the most constraining hypothesis at this stage is recommended.

The Coordination Entity shall verify that all TSOs have provided their structural data and that the information provided by the TSOs is relevant to the process (based on the information previously provided by the TSOs, comparisons of similar data from two or more TSOs, and any other relevant information the Coordination Entity holds). If necessary, the Coordination Entity shall request that the TSOs update their input data.

At the request of the Coordination Entity, TSOs shall verify the validity of the information provided regarding the model structure. If invalid, updated information shall be provided in response to the Coordination Entity's comments.

Using the data provided by the TSOs, the Coordination Entity integrates all model structure changes into the existing reference file. At this stage, both the model and structural database are up to date with the structural situation of the following year. No forecast or schedule data is included at this stage.

The Coordination Entity distributes the published model structure to all TSOs.

From July, TSOs prepare and send the Coordination Entity the forecast and schedule data for the different agreed scenarios for the following year.

For each scenario, the data shall include the following:

- The demand forecast
- The load profile on the network (by substation)
- If necessary, the amount of expected load shedding
- The generation schedule matching the demand
- The planned generation forecast for intermittent generation (Renewable Energy Sources, RES)
- The expected bilateral exchange planning
- Any specific topology of network
- The planned outages

The data template for each scenario will be provided to the TSOs by the Coordination Entity.

The Coordination Entity shall verify that all TSOs have provided their forecast and schedule data, and so that the information provided by the TSOs is relevant, based on the following:

- Previously provided information from TSOs
- A comparison of similar data provided by two or more TSOs

- The forecasts made directly by the ICC for the entire region
- Any other relevant information the ICC holds

Where necessary, the Coordination Entity shall send a request to the TSOs for the update of the input data.

At the request of the Coordination Entity, and whenever inconsistencies are detected, the TSOs shall verify if the information provided regarding the forecast and schedule data is realistic. If unrealistic updated information shall be provided in response to the Coordination Entity's comments.

Using the data provided by the TSOs, the Coordination Entity integrates all forecast and schedule data into the model structure prepared during the previous step. Specifically, all data related to generation, demand and topology shall be updated for all agreed scenarios. The resulting output shall be a CGM for each agreed scenario.

Once the hypotheses provided by the TSOs are integrated into the model structure, the Coordination Entity shall verify that the resulting CGMs are consistent. The models shall produce results that, from operational experience, are close to expectations. Consistency is also verified according to the following criteria:

- The generation plan is balanced between the countries and the generation units.
- The expected physical power flows on the interconnections respect the commercial bilateral contracts.
- The overhead lines and transformers are operated within their nominal ranges.
- The voltage profile respects the admissible voltage range.

Where inconsistencies are identified, the Coordination Entity shall require the TSOs to determine the issues and provide a solution.

Following this request, TSOs shall identify the sources of the inconsistencies, update their data accordingly, and resubmit them to the Coordination Entity. This part of the process will iterate until the quality of data is deemed satisfactory by the Coordination Entity or a given deadline is reached.

The Coordination Entity shall prepare a report explaining how the CGMs were prepared, and for each, the considered hypotheses. This report shall contain at least the following:

- Major changes introduced in the model structure compared to the previous year.
- Hypotheses used in forecasting the demand and RES generation for each country.

- Hypotheses used in the generation schedule for each country.
- A preliminary analysis of constraints identified through operational planning studies.

The preparation of the CGMs and the associated report shall be validated by the Coordination Entity and distributed to all members.

7

Coordinated Capacity Calculation Procedure

7.1 Capacity calculation – phase 0 (MVP)

The flowchart in Figure 7.1 shows the proposed process for the coordinated Capacity Calculation procedure in phase 0 (MVP), along with recommended deadlines for the required activities. The coordination at this phase consists of bilateral agreements between TSOs and shared network data are limited to the topology. The process is designed to balance completeness with simplicity of implementation, particularly for members that do not yet perform coordinated capacity calculation procedures.

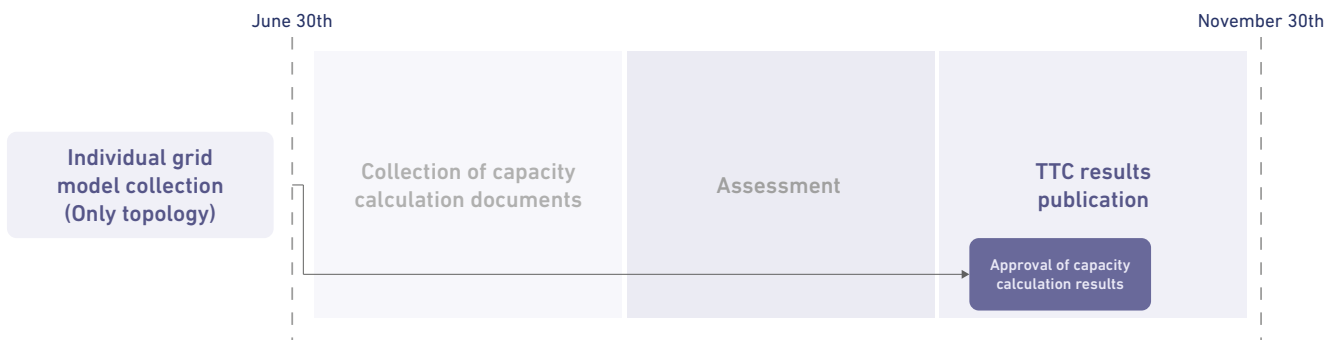


Figure 7.1 Coordinated capacity calculation model – phase 0 (MVP)

In this phase, given the lack of a power flow CGM, coordinated capacity calculation is based on topology data only in respect to the networks of neighbouring TSOs. Phase 1 is required for detailed coordinated capacity calculation.

7.2 Capacity calculation – phase 1

The flowchart in Figure 7.2 shows the proposed process for the coordinated capacity calculation procedure in phase 1, along with recommended deadlines for the required activities. Coordination at this phase still consists of bilateral agreements between TSOs but, unlike phase 0 (MVP), the coordinated capacity calculation is based on simplified power flow models.

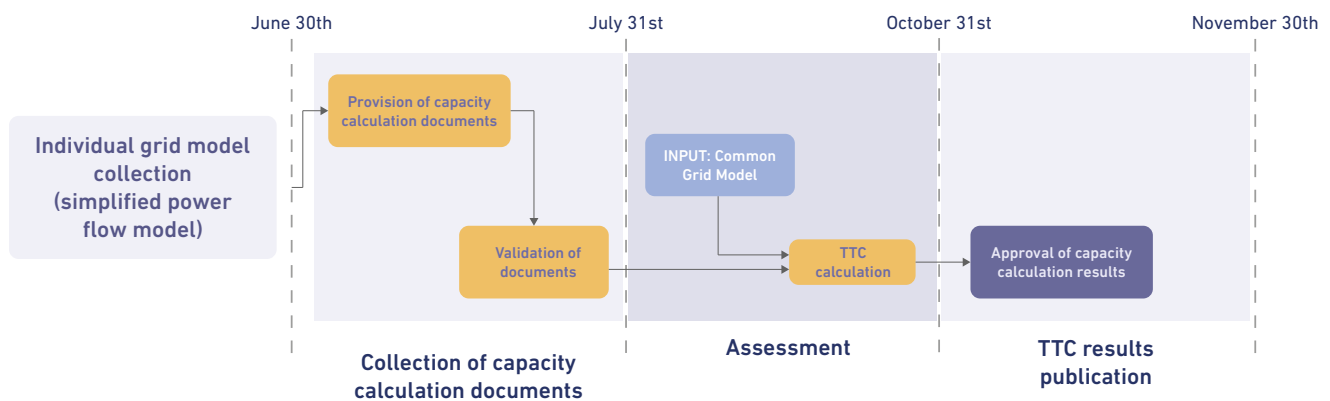


Figure 7.2 Coordinated capacity calculation model – phase 1

TSOs shall request the following documents from their neighbours in order to perform the calculation:

- **Network constraints document:** a document setting out the internal transmission capacity of lines that may limit border exchanges (TTC), covering only those lines represented in the simplified power flow model (i.e. the CGM).
- **Remedial actions document:** a document setting out topology changes, special protection schemes, interruptible customers, and generation re-dispatching to address emergency condition, covering only those network elements represented in the simplified power flow model (i.e. the CGM).
- **Already allocated capacity document:** a document setting out long-term bilateral contracts on the border, as this kind of exchange has already been planned and takes priority over other exchanges.

A common format for each of the above-mentioned documents shall be defined by the involved TSOs. Before the end of October, each TSO shall perform the coordinated capacity calculation

and, following validation from the other involved TSO, results shall be validated before the end of November.

7.3 Capacity calculation – phase 2

The flowchart in Figure 7.3 shows the proposed process for the coordinated capacity calculation procedure in phase 2, along with recommended deadlines for the required activities. The coordination at this phase is no longer restricted to bilateral agreements only (as in phase 1). Coordinated regions shall be defined and, for each, a Coordination Entity shall be entrusted to perform coordination activities. The shared network data are now detailed power flow models.

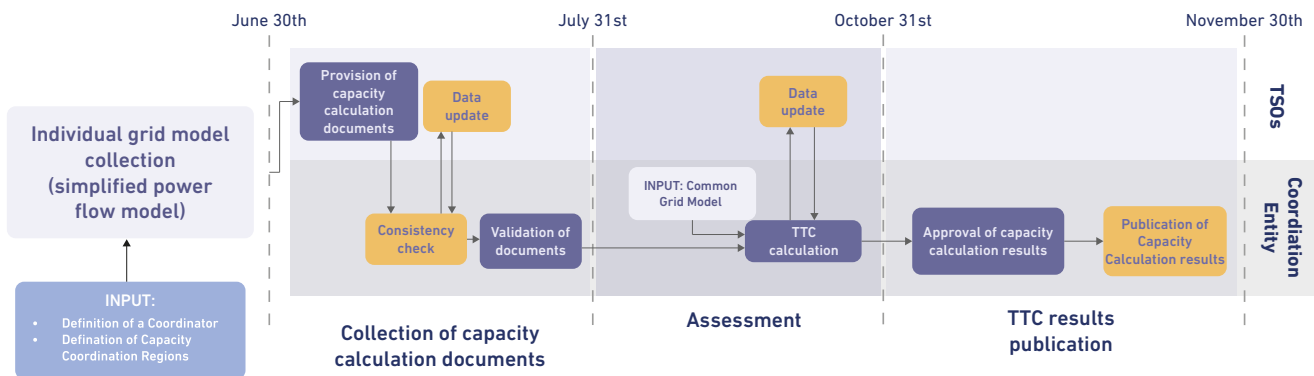


Figure 7.3 Coordinated capacity calculation model – phase 2

Med-TSO members shall agree on the electrical regions within which security and adequacy assessments will be performed. Defining a region requires evaluations covering network security, market efficiency, stability and robustness. Once the regions are defined, common emergency actions/rules to address large perturbations shall be implemented.

Once the regions are defined, member states within a region may propose a Coordination Entity to perform the coordinated capacity calculations for each TSO within the Region. The Coordination Entity shall be approved by the Technical Committee Operation.

To perform the calculation, the Coordination Entity shall collect the following documents from each TSO:

- **Network constraints document:** a document setting out the internal transmission capacity of lines that may limit border exchanges (TTC).

- **Remedial actions document:** a document setting out topology changes, special protection schemes, interruptible customers, and generation re-dispatching to address emergency conditions.
- **Generation and Load Shift Keys (GLSK) document:** a document setting out the merit order of generators and loads (where necessary) to be considered during TTC calculation, to determine the operating limits of transmission capacity on the border (in import and export).
- **Already allocated capacity document:** a document setting out long-term bilateral contracts on the border, as this type of exchange has already been planned and takes priority over other exchanges.

The Coordination Entity shall define and communicate to all TSOs, a common format for each of the above-mentioned documents. It shall collect and validate the required documents before the end of June. Before the end of October, the Coordination Entity shall finalise the TTC calculation and, following validation from each TSO, shall publish the results before the end of November.

8

Coordinated Outage Planning Procedure

8.1 Outage planning – phase 0 (MVP)

The flowchart in Figure 8.1 shows the proposed process for the coordinated outage planning procedure in phase 0 (MVP), along with recommended deadlines for the required activities. Coordination at this phase consists of bilateral agreements between TSOs, with shared network data limited to the topology. The process is designed to balance completeness with simplicity of implementation, particularly for members that do not yet perform coordinated outage planning procedures.

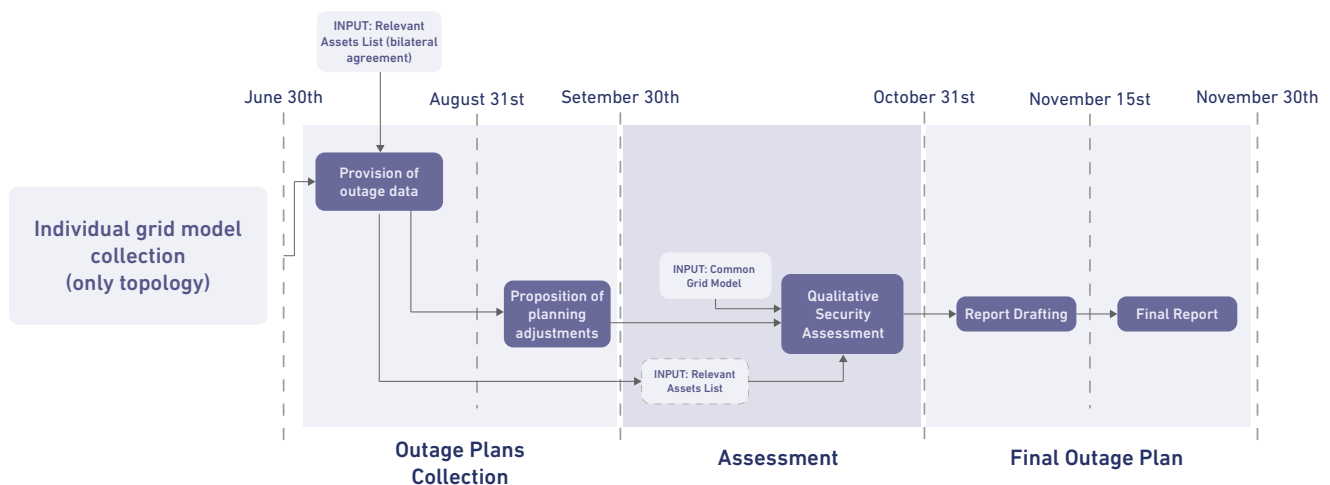


Figure 8.1 Coordinated outage planning model – phase 0 (MVP)

In accordance with the Common Grid Model (topology only, in phase 0), the relevant assets list shall be defined by bilateral agreement between the involved TSOs. A pre-defined criterion for compiling the relevant assets list can be implemented by the TSOs (e.g. treating relevant assets as the second node of the grid beyond the borders).

TSOs shall prepare and send to each other (in bilateral coordination) their outage plans for the following year, focusing on the network elements defined in the relevant assets list.

Data will be provided in the format agreed upon between the TSOs involved in the bilateral coordination.

The information provided by the TSOs shall have already been studied to ensure that all operational security limits are respected on the national network and that outage planning has already been agreed on with the relevant different stakeholders in the country (generation companies, distribution companies, industrial clients, etc.).

Accordingly, the involved TSOs shall provide outage planning adjustments proposals, according to criteria such as:

- Maintenance activity is allocated, as far as possible, to periods in which the energy transfers are statistically the lowest.
- Maximising cross-border NTC/ATC (e.g. avoiding outages on several network elements simultaneously.)
- Minimising the down time of transmission system elements.
- Avoiding repeated outages or capacity reductions for works that can be performed in parallel.
- Avoiding scheduled outages at borders during periods in which one or more interconnected member states are in an under-capacity regime and have requested support from neighbouring TSOs.

TSOs shall study the proposed planning adjustments to avoid incompatibilities between the different planned outages. When seen as satisfactory, TSOs shall validate the proposed adjustments.

Based on the information provided, the TSOs involved in the bilateral coordination shall perform a qualitative assessment, before the end of October, to draft and finalise the Coordinated Outage Planning Report before the end of November.

The report shall outline the following:

- The list of outages.
- The list of detected constraints.
- The list of preventive and curative remedial actions.

8.2 Outage planning – phase 1

The flowchart in Figure 8.2 shows the proposed process for the coordinated outage planning procedure in phase 1, along with recommended deadlines for the required activities. Coordination at this phase still consists of bilateral agreements between TSOs but, unlike phase 0 (MVP), the coordinated outage planning is based on simplified power flow models.

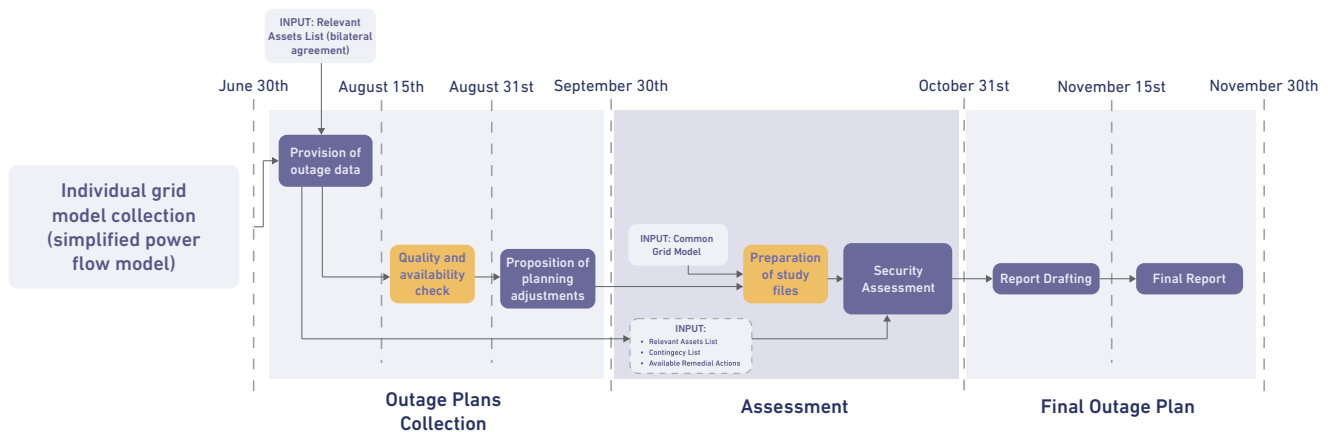


Figure 8.2 Coordinated outage planning model – phase 1

In accordance with the Common Grid Model (simplified power flow model, in phase 1), the relevant assets list shall be defined by bilateral analysis between the involved TSOs. The relevant assets previously defined in phase 0 shall now be updated by performing power flow calculations and identifying other network elements to be considered relevant for the coordinated outage planning procedure. This activity shall be performed and validated by both TSOs involved in the bilateral coordination.

TSOs shall prepare and send to each other (in bilateral coordination) the required data:

- The outage plans for the following year focusing on the network elements defined in the relevant assets list.
- Their contingency list, based on the network elements reported in the CGM of this phase.

- Their available remedial actions, based on the network elements reported in the CGM for this phase.

The information provided shall have already been studied to ensure that all operational security limits are respected on the national network and that outage planning has already been agreed with the relevant stakeholders in the country (generation companies, distribution companies, industrial clients, etc.). Data will be provided in the format agreed upon between the TSOs involved in the bilateral coordination.

Based on the information provided by the TSOs and on the CGMs (simplified power flow model, in phase 1) representing the different scenarios for the following year, the TSOs shall prepare a set of study files corresponding to that year. Each file shall contain the planned outages of the relevant period to represent a forecast for that period.

The assessment shall be performed by the involved TSOs before the end of October, based on established system operating limits (SOLs) and interconnection reliability operating limits (IROLs), and using the contingency lists provided by the TSOs.

The involved TSOs shall prepare a report summarising the agreed final outage plan.

The report shall outline the following:

- The list of outages.
- The list of detected constraints.
- The list of preventive and curative remedial actions.

8.3 Outage planning – phase 2

The flowchart in Figure 8.3 shows the proposed process for the coordinated outage planning procedure in phase 2, along with recommended deadlines for the required activities. Coordination at this phase is no longer restricted to bilateral agreements alone (as in phase 1). Coordinated regions shall be defined and, for each, a Coordination Entity shall be entrusted to perform coordination activities. The shared network data are now detailed power flow models.

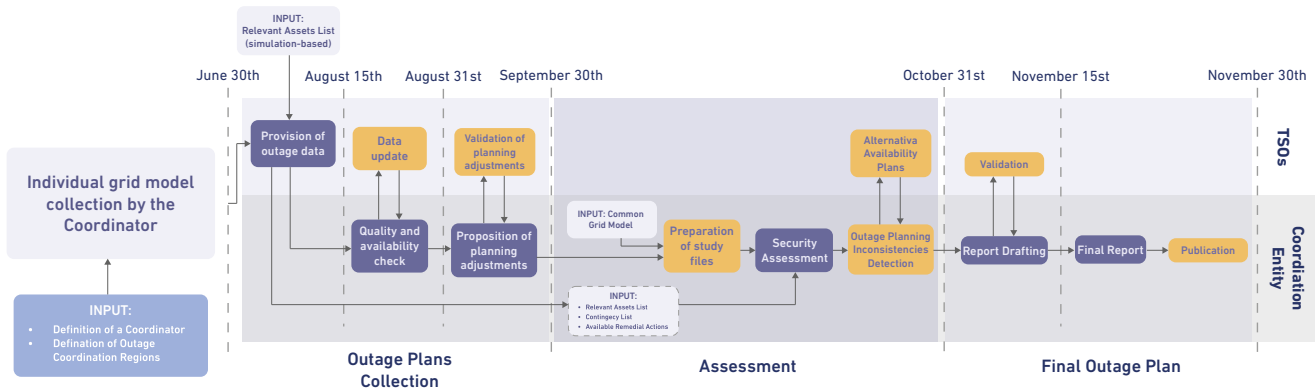


Figure 8.3 Coordinated outage planning model – phase 2

The coordination regions previously defined for the coordinated capacity calculation procedure also apply to the coordinated outage planning procedure.

In the same way, the Coordination Entity previously defined for the coordinated capacity calculation procedure shall also serve as the Coordination Entity for the coordinated outage planning procedure.

Following creation of the Common Grid Model, the Coordination Entity shall perform system studies to define the relevant assets for each member state for each supplied scenario. The Coordination Entity may use the relevant assets list defined in phase 1 as a starting point.

The relevant assets shall be updated where large permanent failures occur on the transmission grid or generation units, and also updated to reflect additional scenarios at the request of the involved TSOs.

TSOs shall prepare and send to the Coordination Entity the required data:

- Their outage plans for the following year.
- Their contingency list.
- Their available remedial actions.

The information provided shall have already been studied to ensure that all operational security limits are respected on the national network and that outage planning has already been agreed

with the relevant stakeholders in the country (generation companies, distribution companies, industrial clients, etc.). Data will be provided in the format specified by the Coordination Entity and agreed by TSOs.

The Coordination Entity shall verify that TSOs have provided the required data and that it is of sufficient quality for the outage planning coordination study. If not, the Coordination Entity will ask TSOs to provide data updates. Upon request by the Coordination Entity, all TSOs shall provide additional data on their own outage plans.

Accordingly, the Coordination Entity shall provide outage planning adjustment proposals to the TSOs, according to criteria such as:

- Maintenance activity is allocated, as far as possible, to periods in which energy transfers are statistically at their lowest.
- Maximising cross-border NTC/ATC (e.g. avoiding outages on several network elements simultaneously).
- Minimising the downtime of transmission system elements.
- Avoiding repeated outages or capacity reductions for works that can be performed in parallel.
- Avoiding scheduled outages at borders during periods in which one or more interconnected member states are in an under-capacity regime and have requested support from neighbouring TSOs.

TSOs should study the planning adjustments proposed by the Coordination Entity to avoid incompatibilities between the different planned outages. Where satisfactory, the TSOs shall validate the proposed adjustments.

Based on the information provided by the TSOs and the CGMs representing the different scenarios for the following year, the Coordination Entity shall prepare a set of study files corresponding to that year. Each file shall contain the planned outages of the relevant period to represent a forecast for this period.

The assessment shall be performed by the Coordination Entity before the end of October, based on established system operating limits (SOLs) and interconnection reliability operating limits (IROLs), and using at least the contingency lists provided by the TSOs.

For each constraint detected on the network, the Coordination Entity shall identify the necessary remedial actions from the list provided by the TSOs and propose others, if needed.

TSOs shall study the remedial actions proposed by the Coordination Entity to avoid any outage planning Inconsistencies between different planned outages. Where the proposal is satisfactory, the TSOs shall validate the proposed remedial actions. When more than one TSO is involved, agreement is needed between the relevant TSOs.

The Coordination Entity shall prepare a report summarising the agreed final outage plan. The report shall cover:

- The list of outages.
- The list of detected constraints.
- The list of preventive and curative remedial actions.

The regional outage planning shall be validated by the Coordination Entity and distributed to all relevant TSOs before the end of November.

9

Implementation Roadmap

Med-TSO members, either directly or entrusting the Technical Committee Operation with the task, shall monitor progress against the following implementation milestones.

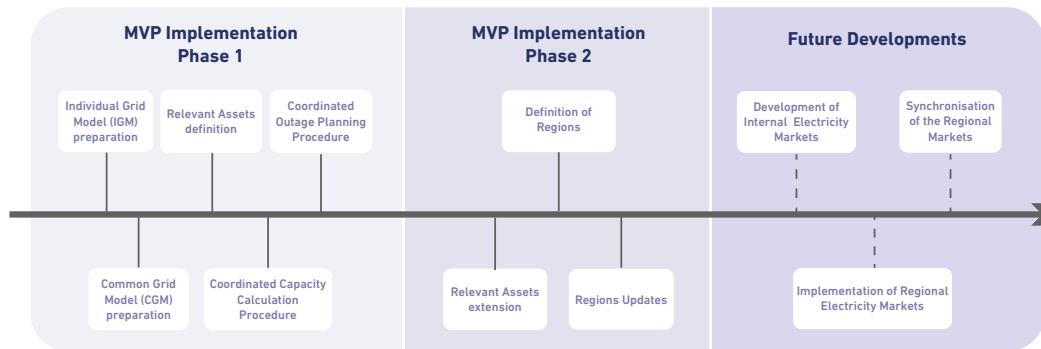


Figure 9.1 MVP implementation phases

1. Preparation of Individual Grid Models (IGM)

- Each member state shall prepare its own individual grid as a starting point for the creation of a Common Grid Model, according to a common data format previously defined by the Technical Committee Operation.
- The Technical Committee Operation may identify one or more member states with previous experience in creating an individual grid model to help other member states finalise this task.
- Individual Grid Models of different member states shall refer to the same period, so that they can be merged into the Common Grid Model at a later stage.
- The Technical Committee Operation shall define a standard communication protocol for the IGM data sharing.

2. Creation of a Common Grid Model of the Med-TSO ring

- Med-TSO Members Operation shall establish an entity responsible for collecting all the Individual Grid Models and required data for the creation of the Common Grid Model.
- The Common Grid Model file format will be the same as that defined for the individual grid models.
- Med-TSO members, either directly or by entrusting the Technical Committee Operation, shall agree on a dedicated procedure with the details concerning the CGM update methodologies and update frequencies. Each member state shall approve this procedure.

3. Definition of relevant assets

- Following creation of the Common Grid Model, the Coordination Entity shall perform system studies to define the relevant assets for each member state for each supplied scenario.
- The relevant assets shall be updated where large permanent failures occur on the transmission grid or generation units.

4. Definition of a coordinated capacity calculation procedure

- Med-TSO Members, either directly or by entrusting Technical Committee Operation, shall agree on a dedicated procedure for the coordinated capacity calculation.
- The procedure shall define the coordinated capacity calculation methodology. As a starting point, the recommended methodology is CNTC (Coordinated Net Transfer Capacity).
- The procedure shall define data format for all the documents required for the

coordinated capacity calculation (like network constraints, remedial actions, key shifts, already allocated capacity).

- The procedure shall also define a standard communication protocol for capacity calculation data, as well as the deadlines for sharing it.

5. Definition of a coordinated outage planning procedure

- Med-TSO members, either directly or by entrusting the Technical Committee Operation, shall agree on a dedicated procedure for the coordinated outage planning.
- The procedure shall define the format of outage planning data.
- The procedure shall define a standard communication protocol for outage planning data.

6. Relevant assets extension

- The relevant assets shall be updated taking into consideration additional scenarios, at the request of the involved TSOs.

7. Definition of regions

- Med-TSO members, either directly or by entrusting Technical Committee Operation with the task, shall identify possible electrical regions within which security and adequacy assessments will be performed. This task will be based on static and dynamic system studies using the Common Grid Model.
- Common emergency actions to address large perturbations shall be defined for each region.
- Member states of a region may propose a regional Coordination Entity, responsible for:
 - Performing a coordinated outage plan for the region.
 - Performing capacity calculations for each TSO within the region.

The Regional Coordination Entity shall be approved by the Technical Committee Operation.

8. Regions update

- Due to network developments and renewable energy penetration, a continuous analysis and update of region definitions is required.

9. Development of internal electricity markets

- Unbundling for integrated electricity companies.

- Implementation of system operators.
- Liberalisation of the generation sector to promote new investments and improve competition.
- Implementation of market operators.
- Implementation of a single buyer in the first stage, followed by the development of a free market.

10. Development of regional electricity markets.

- Implementation of market coupling (energy market) within the region.
- Development of an IT platform for ancillary services.

11. Synchronisation of regional markets.

- Creation of a single Med-TSO electricity market.

10

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11

Appendix – Work Programme

The work programme of Rules and Protocols for Increased Coordination of Power Systems is built around two major pillars: surveying members' best practices and assessing European regulations for coordination activities among European TSOs.

The following section addresses each pillar, summarising the key activities carried out in each.

11.1 Survey preparation and data collection

The objective of this task is the preparation of two surveys, one for each stream covered in this activity, and their submission to member TSOs to collect input on current practices, tools and expected future improvements.

The first survey focuses on outage planning.

The purpose of outage planning is to coordinate proposed generation and relevant grid outages that have the potential to create unacceptable system conditions and to advise TSOs to put in place remedial actions in anticipation of such outages.

Drawing on international experience, outage planning covers different time frames, e.g. Y-1, W-1 and D-1. The survey covers all these timeframes.

The objective of the survey is to gather information on the following:

- Geographical scope of the coordination.
- Timeframes covered in the process.
- Entities identified and involved in the process (e.g. neighbouring TSOs, business unit in charge of the planning, etc.).
- Studies carried out to validate the outage plan (e.g. N-1 security assessment).
- Ways to report and share results.
- Data exchange procedures and protocols
- Transparency rules
- Criteria for identifying outages to be considered in outage planning.
- Main input data for the process.
- Timing and deadlines.
- Security analysis, remedial actions considered, and validation.

The second survey to be conducted during the project execution covers **capacity calculation**.

Capacity calculation is the process of estimating the total transfer capacity and/or net transfer capacity of cross-border tie-lines for the next timeframe (e.g. a year, a week or a day). Different methodologies exist for calculating transfer capacity (NTC, CNTC, FB) and these are usually defined in the Common Grid Code

Capacity calculation is commonly estimated over Y-1, W-1, and D-1-time horizons. As with the outage planning survey, the capacity calculation survey is articulated according to the timeframes covered in the coordination processes followed at the time of execution.

The objective of the survey is to gather information on the following:

- Calculation methodology adopted (NTC, etc.).
- Timeframes covered in the process.
- Entities identified and involved in the process (e.g. neighbouring TSOs, business unit responsible for the planning, etc.).

- Studies carried out to validate capacity calculation (e.g. N-1 security assessment).
- Ways to report and share results.
- Degree of coordination between entities.
- Main input data for the process.
- Timing and deadlines.

11.2 Assessment of current EU regulations and practices

The assessment of European Commission regulations and practices consisted of collecting and analysing the following:

- Commission Regulation (EU) 2017/1485 of 2 August 2017 Establishing a guideline on electricity transmission system operation
- Commission Regulation 1222/2015 of 24 July 2015 Establishing a guideline on capacity allocation and congestion management

ENTSO-E applies different strategies depending on the capacity calculation region involved. The core CCR applies flow-based capacity calculation [2], whilst different regions apply NTC-based approaches. The JWG paid special attention to this point, as Med-TSO members that are also ENTSO-E Members belong to different capacity calculation regions (Figure 11.1). This places constraints on the Minimum Value Proposition, since non-CCR members should not be a-priori required to adopt flow-based capacity calculation unless significant advantages have been foreseen for the whole Med-TSO organisation.

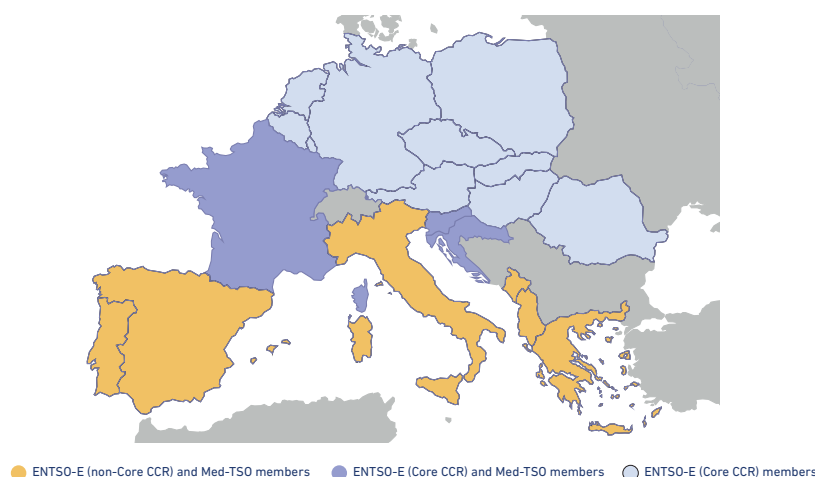


Figure 11.1 Overlapping between ENTSO-E's Core CCR and Med-TSO

11.3 Assessment of current EU regulations and practices

The final task of the project is to select and refine the best practices identified during project execution and incorporate them into the MVP for the Med-TSO coordination target model. The MVP provides a target model for outage coordination and capacity calculation.

12

Appendix II – Survey benchmarking and questionnaire guidelines

In accordance with the general approach described in Chapter 7, the project team developed two surveys to collect information from Med-TSO members about coordination activities. The surveys were conducted through questionnaires [3] and [4], aimed at facilitating best-practice sharing, identification of common challenges, and standardisation opportunities.

The survey structure is built around three layers of information collection:

- I. **Understanding of the topic.** This layer aims at understanding if and how deeply each member understands the concept of coordination, along with associated challenges and opportunities.
- II. **Implementation.** This layer aims at collecting information on how the members carry out their coordination activities across different time horizons.
- III. **Detailed implementation.** This layer aims at gathering granular information on the execution of the coordination activities.

To support the understanding of the topic, the project team has identified for each survey a

common approach, a reference business process, based on public data of Med-TSO members and other system operators. This process was then used to develop the list of questions in the questionnaires.

The reference business process is a high-level description of the coordination procedure and represents the first effort of this activity towards standardising concepts and definitions among Med-TSO members. The surveys will highlight similarities and differences in the procedure followed by members and will support the Joint Working Group in identifying a common process on which to build the Minimum Value Proposition for the organisation.

The surveys are structured around three key pillars:

- **Division of questions by content:** questions are categorised based on their content to ensure clarity and focus.
- **Step-by-step methodology:** each section contains different types of questions (basic yes/no questions, short-answer questions, detailed argumentative questions) allowing answers at different levels of detail. The final stage also includes the provision of any relevant documentation, standards, or internal processes.
- **Applicability and flexibility:** this approach allows utility members to answer basic questions and skip those that are not applicable to their specific case.

The following sections provide survey guidelines aimed at helping respondents familiarise themselves with the major concepts and definitions used in the reference business process.

12.1 Outage coordination survey guidelines

This benchmarking survey is intended to gather comprehensive insights into how Med-TSO members perform outage coordination. It is derived from the high-level business process schematically presented in Figure 12.1.

Outage coordination is the process of coordinating the schedule of proposed generation and relevant grid outages that have the potential to create unacceptable system conditions, with a specific focus, for the purpose of this activity, on cross-border energy exchanges. The coordination process enables the involved TSOs to put in place remedial actions in anticipation

of such proposed outages.

Different entities may be involved in the coordination of the planned outages: TSOs, who are generally responsible for the operation and maintenance of cross-border tie-lines; and owners of any other asset whose unavailability may impact on the operation of two or more interconnected grids.

The coordination process requires definition of the extent covered by the coordination, two or more grids (a “region”,) which operation is impacted by the outages, and the role and responsibilities of each party (entities) involved in the process.

As shown in Figure 12.1, the reference outage coordination business process begins with the identification of the grid components whose outages significantly impact the system and the region where that impact will be evaluated and mitigated. The final outage plan is then identified iteratively through security analysis, schedule adjustments and activation of mitigation solutions.

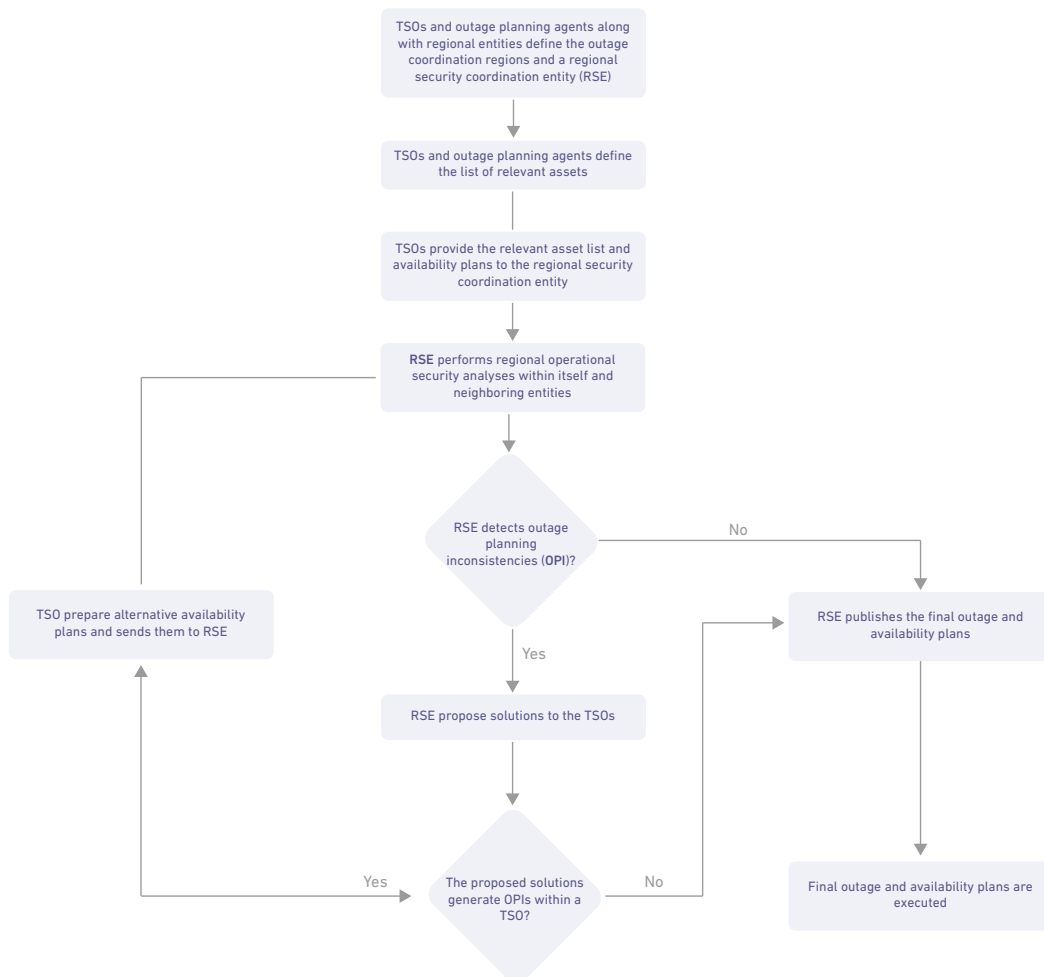


Figure 12.1 High-level overview of the outage planning coordination business process

On the division of questions by content pillar, the survey is divided as follows:

1. **General and organisational:** gathers basic background information about member utilities, including organisational structures, the existence and status of the interconnections with neighbouring utilities, and commercial relations with interconnected utilities.
2. **Outage planning processes:** covers how member utilities generally perform outage planning, the division of responsibilities within a member utility during the outage planning coordination, and regulatory frameworks guiding their outage coordination practices. It also explores the presence of a Regional Coordination Entity, which performs regional coordination, the methodology used to define such a region, the members participating in the coordination, and the division of responsibilities within the entity.
3. **Relevant assets definition:** focuses on how every member utility identifies, defines, manages, and regularly updates their lists of relevant grid assets, whose outages significantly impact operational reliability or cross-border transmission capacity. This section also sheds light on the type of parties involved in such definition within a member utility, the timeframes for updating this list, and the process for resolving internal or external outage planning inconsistencies.
4. **Communication and data sharing:** studies the communication methods, tools, standards, and protocols member utilities use for internal and external information exchange in outage planning coordination, and the limitations encountered.

All relevant terminologies and definitions used throughout this survey are provided in Table 12.1. Survey recipients were invited to refer to this table for clarity when responding.

Term	Definition
Capacity Calculation	Determining available transmission capacity considering planned/unplanned outages.
CIM (Common Information Model)	Standardized data exchange format (IEC standard) widely used for exchanging grid information among TSOs.
Contingency Planning	Developing specific action plans to manage unexpected or high-impact events during outages.
Cross-Border Coordination	Coordinating outages affecting lines or systems connecting multiple TSOs or countries.
Forced Outage	Unplanned outages due to unexpected failures or conditions.
Freeze Period	A timeframe during which alterations to confirmed outage schedules are limited or restricted.
Outage Coordination	The structured process to manage and harmonize planned outages to maintain system reliability.

Outage Planning Agents	Entities or individuals responsible for submitting, coordinating, approving, and managing planned outages within or across Transmission System Operators (TSOs).
Outage Planning Incompatibilities	Unplanned situations in which two or more proposed outages cannot be scheduled simultaneously due to operational, reliability, safety, or regulatory constraints. These incompatibilities must be identified and resolved through coordinated outages due to unexpected failures or conditions.
Planned Outage	Scheduled maintenance or operational procedures requiring equipment disconnection from the grid.
Regional Coordination Entity	An entity tasked with supporting multiple TSOs in a specific region by performing coordinated security analyses, outage coordination, capacity calculations, and providing recommendations to ensure regional grid reliability and security.
Relevant Assets	Generation units, transmission lines, transformers, substations, HVDC links, reactive compensation devices, or other grid components whose outages significantly impact system reliability, capacity, market operation, or cross-border flows.
Reliability Margin (RM/-TRM)	Transmission Reliability Margin: reserved transmission capability to ensure system reliability during uncertainties or planned outages.

Table 12.1 Relevant terminology regarding outage planning coordination survey

12.2 Capacity calculation survey guidelines

This benchmarking survey is intended to gather comprehensive insights into how TSOs in Med-TSO perform capacity calculation. The survey is derived from the high-level reference business process for capacity calculation presented in Figure 12.2.

Capacity calculation is the process of estimating the Total Transfer Capacity (TTC) and Net Transfer Capacity (NTC) between interconnected grids or areas. Capacity calculation is typically carried out for different time horizons, year-ahead (Y-1), week-ahead (W-1), and day-ahead (D-1). The detailed process of estimating TTC or NTC for any time horizon may differ, though the structure of the procedure and key activities remain the same.

The capacity calculation reference process leverages the definition of capacity calculation region, an interconnected grid where (cross-border) energy exchanges are established and the largest transfer to be estimated. Within this procedure, an entity oversees the capacity calculation, whose results are then shared with all the stakeholders within the region.

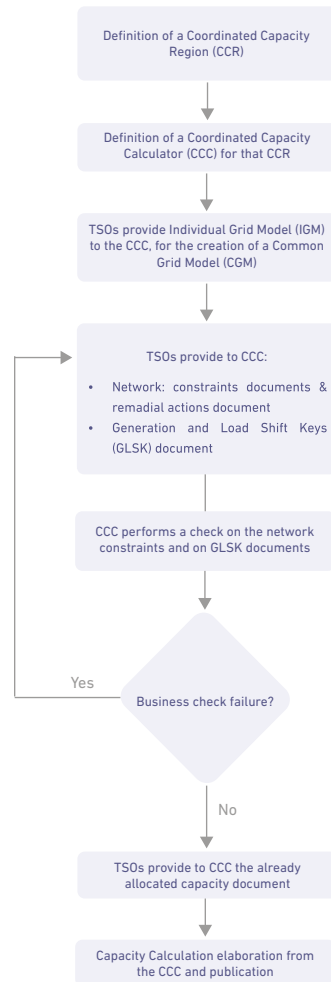


Figure 12.2 High-level overview of the outage planning coordination business process

Regarding the division of questions by content, the survey is structured as follows:

- 1. Section 1:** gathers basic background information about the capacity calculation process of the involved TSO.
- 2. Section 2:** gathers more detailed information about the capacity calculation coordination with respect to neighbouring TSOs.

All relevant terminology and definitions used throughout this survey are provided in Table 15.2. Survey recipients were invited to refer to this table for clarity when responding.

Term	Definition
Capacity Calculation	Process of determining the maximum amount of electricity that can be transmitted across "different parts" of the power grid while ensuring operational security and efficiency. This involves translating physical transmission limits into commercial trading limits, considering various factors such as grid constraints, generation, and load patterns.
Capacity Calculation Region (CCR)	Geographic areas in which a coordinated capacity calculation is applied.
Common Grid Model (CGM)	Data set agreed between various TSOs describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the coordinated capacity calculation process. Result of the merger of more Individual Grid Models.
Coordinated Capacity Calculator (CCC)	The entity (or entities) with the task of calculating transmission capacity, at regional level or above.
Flow-Based Methodology	Methodology to calculate the maximum allowable electricity flows by considering the physical constraints of the entire network. This approach accounts for the interdependence between different network elements and optimizes the use of the grid by considering the actual physical flows.
Generation and Load Shift Key (GLSK)	It describes how a change in the net position of an area (i.e., the balance between supply and demand) affects the power output of the generation units and the load within that area.
Individual Grid Model (IGM)	A data set describing power system characteristics (generation, load, and grid topology) and related rules to change these characteristics during capacity calculation, prepared by the responsible TSOs. More Individual Grid Models are merged to form the Common Grid Model.
Net Transfer Capacity (NTC) Methodology	Methodology to calculate the maximum exchange capacity between two bidding zones independently of other exchanges. It refers to a capacity calculation method where Transmission System Operators (TSOs) jointly determine the maximum exchange capacity between bidding zones, taking into account operational security constraints and coordinating across borders. This approach is simpler

Table 12.2 Relevant terminology regarding capacity calculation coordination survey

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Appendix III – Assessment of international regulations and codes

The reliability, resilience and efficiency of modern power systems are deeply dependent on effective coordination and planning.

Among the most critical aspects of system operation are outage coordination and capacity calculation, which together ensure that generation, transmission, and distribution infrastructures can meet demand reliably, even under constrained conditions.

In interconnected power systems, whether regional grids or continental-scale networks like those in North America, Europe, and parts of Asia, the complexity of system operation multiplies. The interdependence of national and subnational networks demands a harmonised approach for planning outages due to maintenance or infrastructure upgrades, so that system adequacy and security are never compromised.

Outage coordination involves the scheduling of planned outages of generation and transmission assets in a way that minimises risk to system reliability. This coordination must consider seasonal demand patterns, availability of alternative resources, real-time operational constraints, and cross-border impacts. Global best practices often involve transparent information-sharing

platforms, collaborative planning tools, and advanced modelling techniques to forecast system conditions and assess potential vulnerabilities.

Similarly, capacity calculation, whether for resource adequacy assessments or for market-related capacity allocation, plays a vital role in ensuring that sufficient infrastructure is available to support reliable operation under both normal and contingency conditions. This process encompasses the evaluation of firm generation availability, network constraints, demand forecasts, and reserve margins. It also reflects evolving considerations such as the integration of renewable energy sources, storage technologies, and flexible demand.

Various regulatory bodies and system operators worldwide, such as ENTSO-E in Europe, and NERC in North America have developed sophisticated frameworks for outage coordination and capacity calculation. These frameworks are increasingly data-driven, stakeholder-inclusive, and responsive to emerging challenges such as climate resilience, cyber threats, and the decarbonisation of energy systems.

This section explores the foundational principles, technical methodologies, and operational practices involved in outage coordination and capacity calculation across interconnected power systems.

13.1 NERC – North American Electric Reliability Corporation

The mission of NERC and its six regional entities is to maintain a highly reliable and safe North American bulk power system by effectively and efficiently reducing the risks posed by grid disruptions. NERC, as the Electric Reliability Organisation (ERO) for the United States, develops and enforces mandatory reliability standards, subject to FERC approval. These standards are designed to ensure the reliable operation of the bulk power system.

NERC's reliability standards define the requirements for the planning process and operations of the bulk electric system (BES). These standards are subject to enforcement within the United States and parts of Canada and Mexico. They establish threshold requirements for assuring the bulk electric system is planned, operated, and maintained to minimise risks of cascading failures, avoid damage to major equipment, or limit interruptions of the bulk power system (BPS).

Table 13.1 lists NERC reliability standards and associated topics.

Standard	#	Topic
Standard (BAL) Resource and Demand Balancing	45	Frequency control, Area Control Error (ACE), Contingency Reserve
(CIP) Critical Infrastructure Protection	114	Sabotage protection, cybersecurity
(COM) Communications	12	Telecommunications
(EOP) Emergency Preparedness and Operations	41	Emergency operations planning, alerts, load shedding, disturbance reporting restoration, black start
(FAC) Facilities Design, Connections, and Maintenance	42	Generation, transmission and end-user connection requirements, vegetation management, facility ratings for system modelling
(INT) Interchange Scheduling and Coordination	35	Interchange transactions, tagging and implementation
(IRO) Interconnection Reliability Operations and Coordination	62	Responsibilities and authorities, facilities, operations planning, current day operations, transmission loading relief
(MOD) Modeling, Data, and Analysis	55	TC, ATC, TRM calculation methodologies, capacity benefit margin, modelling data, data exchange, load management
(NUC) Nuclear	6	Coordination between Nuclear Power Plant Generator Operators and Transmission entities
(PER) Personnel Performance, Training, and Qualifications	13	Reliability coordination & responsibility, authority, training, credentials, staffing
(PRC) Protection and Control	107	Protection coordination, fault recording, malfunctioning, maintenance and testing, under-frequency/voltage load shedding, special protection systems
(TOP) Transmission Operations	48	Reliability responsibilities, operations planning, outage coordination, operations, operational data exchange, system monitoring, operating limit violations
(TPL) Transmission Planning	36	System performance, normal and after loss of an element, reports, data

(VAR) Voltage and Reactive	27	Voltage and reactive control
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Table 13.1 NERC reliability standards [5]

The NERC standards consist of almost one hundred standards across fourteen different disciplines. NERC monitors and enforces compliance with these standards through the following six regional entities:

- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability First (RF)
- Southeastern Electric Reliability Corporation (SERC)
- Texas Reliability Entity (Texas RE)
- Western Electricity Coordinating Council (WECC)

The NERC reliability standards are built around four pillars. These were developed in collaboration with the six regional entities and are defined as follows::

- Reliability – to address events and identifiable risks, thereby ensuring the reliability of the Bulk Electric System (BES) through proper mitigation and remediation.
- Assurance – to provide assurance to the public, industry, and government for the reliable performance of the BES.
- Learning – to promote learning and continuous improvement of operations and adapt to lessons learned for BES reliability.
- Risk-based approach – to focus attention, resources, and actions on the issues most important to BES reliability.

Failure by NERC-registered entities to comply with these standards could result in heavy fines based on the severity and duration of the violation. Where an organisation is in violation of standards, the corresponding regional entities assess penalties and monitor approved mitigation plans for compliance.

13.1.1 Outage coordination

The reliability standard concerning outage coordination is IRO-017-1. Several operating roles are involved, such as the Planning Coordinator, Transmission Planner, Reliability Coordinator

and Balancing Authorities.

IRO-017-1 mandates that outages be properly coordinated within the Operations Planning and Near-Term Transmission Planning Horizons and focuses on planned outages of BES elements (transmission lines, generators, etc.) that could impact system reliability.

Key requirements include:

- Planning assessments: each Planning Coordinator (RC) and Transmission Planner must provide their Planning Assessment to the impacted Reliability Coordinators.
- Joint development of solutions: identified issues or conflicts with planned outages in the Planning Assessment must be jointly addressed with the respective Reliability Coordinator(s).

This standard ensures coordination of outages among RCs, TSOs and Balancing Authorities (BA) to maintain reliable BES operations. Outages are often planned at least 1-2 years in advance for major components, with routine updates on a weekly and day-ahead basis. The Reliability Coordinator is responsible for gathering, assessing, and coordinating outage plans submitted by TSOs and BAs. The RC ensures these outages do not collectively threaten system reliability and may also request the rescheduling of outages based on potential impacts.

The effective coordination delivers:

- Prevention of conflicting outages.
- Promotion of inter-regional coordination.
- Proactive adjustments to minimise operational risks.
- Improved situational awareness.
- Reduced risk of cascading failures.

13.1.1.1 Case study: PJM Interconnection (USA)

PJM is one of the largest Regional Transmission Organisations in North America. It coordinates the movement of wholesale electricity in parts of 13 states and Washington, D.C. Table 13.2 maps the PJM coordination process following the general outage planning sub-process introduced in Table 2.1.

1	Outage Request Submission	Outage requests are submitted via a dedicated IT system (PJM's eDART system). Generators, transmission owners, and other entities submit their maintenance or forced outage plans.
2	Preliminary Screening	PJM's preliminary screening covers the following matters <ul style="list-style-type: none"> • System reliability impacts • Market constraints • Overlaps with other outages • Uses real-time and day-ahead models for simulation
3	Reliability Assessment	PJM conducts N-1, N-2, and post-contingency assessments using contingency analysis tool.
4	Coordination among Stakeholders	PJM coordinates with neighboring RTOs (like MISO, NYISO) and utilities to avoid system stress during simultaneous outages
5	Approval or Adjustment	According to previous criteria PJM may: <ul style="list-style-type: none"> • Approve the outage as proposed/requested. • Adjust timing and/or duration. • Deny if it threatens grid security
6	Real-Time monitoring & communication	During execution: <ul style="list-style-type: none"> • Outages are tracked in real-time. • If system conditions deteriorate, PJM can delay or cancel an outage

Table 13.2 PJM outage coordination process

13.1.2 Capacity calculation

The objective of this process is the calculation of inter-area transfer capability to support secure and reliable energy exchange between interconnected transmission operators. Within the NERC framework, the goal of interconnection (or transfer) capacity calculation between TSOs is to:

- Determine how much power can be securely transferred between two or more control areas or regions.
- Identify physical and operational limits (thermal, voltage, and stability) that constrain power flows across interconnections.
- Support system planning, real-time operations, and energy market functionality.
- Facilitate coordination and transparency in inter-regional energy exchanges.

The applicable NERC reliability standards for capacity calculation are:

- MOD-001-2: contains general requirements for ATC and TTC calculation. The purpose of this standard is to ensure that calculations are performed by Transmission Service Providers to maximise the available transmission system capability and verify the respect security criteria adopted on their own systems as well as those of their neighbours.

- MOD-030-3: specifies methodologies for coordinated TTC and ATC calculations across regions. The purpose of this standard is to increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use by entities using the Flowgate Methodology⁴ (like the flow-based approach) to support analysis and system operations.
- IRO-010: relates coordination obligations between Reliability Coordinators and TSOs on inter-regional power flows. The purpose is to prevent instability, uncontrolled separation, or cascading outages that adversely impact reliability; by ensuring the Reliability Coordinator has the data needed to monitor and assess the operation of its area.
- IRO-014: ensures that each Reliability Coordinator’s operations are coordinated so l as not to adversely impact other Reliability Coordinator areas and to preserve the reliability benefits of interconnected operations.
- TOP-001-5: dedicated to preventing instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate such occurrences.
- TOP-003-4: covers operational reliability data and ensures that the Transmission Operator and Balancing Authority have the data needed to fulfil their operational and planning responsibilities.

The capacity calculation process is organised around the following sub-processes (Table 13.3).

1	Define the Transfer Interface	Identify the two (or more) control areas or TSOs involved. Establish the tie-lines and transfer paths that define the interconnection interface.
2	Model-Based Analysis	<p>Use up-to-date system models (as required by MOD-032/033) for both the planning and operational horizon.</p> <p>MOD-032-1: Data for Power System, Modeling and Analysis</p> <ul style="list-style-type: none"> • Purpose: To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system. <p>MOD-033-2: Steady-State and Dynamic System Model Validation</p> <ul style="list-style-type: none"> • Purpose: To establish consistent validation requirements to facilitate the collection of accurate data and building planning models to analyze the reliability of the interconnected transmission system. <p>Include all scheduled maintenance, known outages, seasonal adjustments, and renewable forecasts.</p>
3	Calculate TTC	<p>Simulate steady-state and contingency scenarios:</p> <ul style="list-style-type: none"> • N-0: Normal system configuration • N-1: Single element outage • N-1-1: Sequential outages of critical components <p>Determine the maximum power transfer possible without violating system limits (thermal ratings, voltage bands, stability).</p>

⁴ The flowgate methodology is a way to calculate Available Transfer Capability (ATC) on the power grid by focusing on key transmission elements (flowgates) that are likely to become bottlenecks when power is transferred between regions.

4	Step 4: Derive ATC	$ATC = TTC - TRM - CBM - \text{Existing Transfers}$ Where: <ul style="list-style-type: none"> • TRM: Transmission Reliability Margin • CBM: Capacity Benefit Margin • Existing Transfers: already scheduled flows or commitments
5	Coordinate with Neighbouring TSOs	Validate results through inter-regional coordination. Use flowgate monitoring and real-time system visibility to ensure accuracy.

Table 13.3 Capacity calculation sub-processes as defined by the MOD standard

TSOs must maintain up-to-date transfer capability calculations and report ATC to market participants in real-time, operational limits must be adjusted for unexpected system changes. Reliability Coordinators must have visibility into cross-regional power flows and coordinate emergency actions.

13.2 GCCIA – Gulf Cooperation n Council Interconnection Authority

The GCC Interconnection Authority was established by the members of the Gulf Cooperation Council (GCC) to enhance the reliability and efficiency of electricity networks across the member states through interconnection.

GCCIA is responsible for managing the interconnected power grid among the six GCC member states: Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the United Arab Emirates (UAE). This interconnection facilitates electricity exchange, enhances grid stability, and optimises resource utilisation across the region. The interconnection capacities are determined based on the physical infrastructure of the transmission lines and substations connecting the national grids (see Figure 13.1).

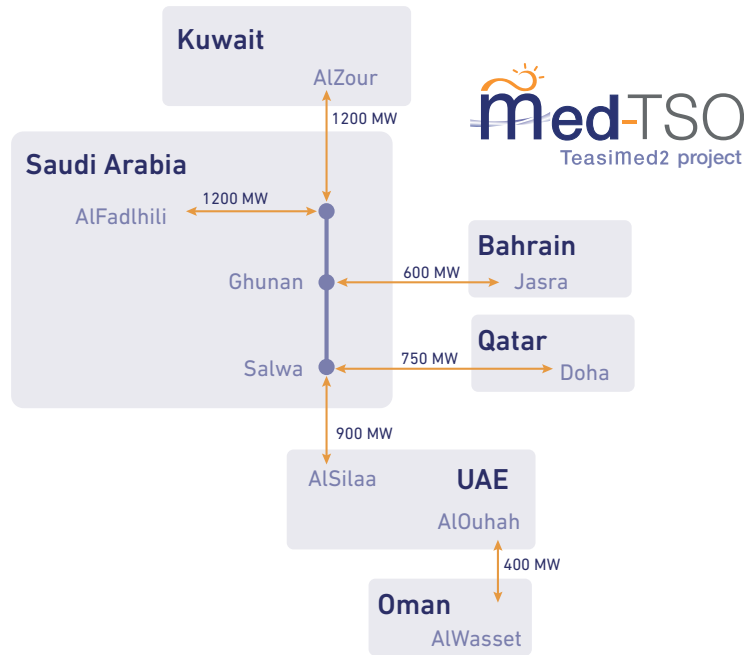


Figure 13.1 GCCIA interconnection layout and transfer capacities

The main objectives of GCCIA are:

- **Power grid interconnection:** to interconnect the electricity networks of the GCC member states (Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the UAE) into a unified grid.
- **Energy security and reliability:** to enhance the reliability of power supply and reduce blackouts by enabling power sharing among member states during emergencies or peak demand periods.
- **Economic efficiency:** to optimise electricity generation costs through regional cooperation, minimising the need for excess reserve capacity in individual countries.
- **Market development:** to facilitate the creation and growth of a competitive regional electricity market in the Gulf region, laying the groundwork for potential integration with wider Arab and international power markets.
- **Sustainability and clean energy:** to support the integration of renewable energy by providing a stable grid infrastructure that accommodates variable power sources across the region.

The operational duties and functions carried out by GCCIA are:

- Managing and maintaining the HV transmission network (backbone) linking the GCC states.
- Provide technical assistance and coordination to ensure system stability, planning, and development of the regional grid.

- Offering a platform for bilateral and multilateral energy trading among GCC countries.
- Developing long-term plans for grid expansion and enhancement in line with growing demand and energy diversification goals.
- Promoting innovation in grid technologies, energy efficiency, and integration of advanced energy systems.

As the body responsible for the operation and planning of the interconnected power system among GCC member states, GCCIA is also involved in capacity calculation and outage coordination. Through comprehensive operational studies, advanced system modelling, and strategic expansion plans, GCCIA ensures that the regional electricity network can meet current and future demands whilst optimising resource utilisation and enhancing grid stability.

13.2.1 Outage coordination

GCCIA's outage planning procedure is a critical component in maintaining the stability and reliability of the interconnected power grid among GCC member states. Through meticulous planning, coordination, and the use of advanced tools, GCCIA ensures that outages are managed effectively, minimising their impact on the overall system.

The primary objectives of GCCIA's outage planning procedure include:

- Minimising system disruptions: ensuring that planned outages have minimal impact on the overall system stability and power supply.
- Coordinating maintenance activities: aligning maintenance schedules across member states to optimise grid performance and resource utilisation.
- Enhancing grid reliability: implementing measures to maintain or improve the reliability of the interconnected grid during outages.
- Facilitating emergency responses: preparing for unplanned outages and ensuring swift and coordinated responses to restore normal operations.

The outage planning process comprises the following sub-processes:

- Identify and schedule planned outages.
- Conduct system studies to assess potential impacts.
- Develop and review switching programs.
- Coordinate with member states and TSOs.

GCCIA collaborates closely with member states TSOs to develop joint outage plans, which define yearly transmission equipment outage plans in coordination with member states.

GCCIA's Operational Scheduling team plays a pivotal role in outage planning by:

- Developing daily and weekly operational plans for control engineers.
- Aligning maintenance schedules between internal teams and member states.
- Processing and managing both planned and unplanned outage requests.
- Assessing the impact of outages on network performance and implementing necessary adjustments.

The Systems Studies team conducts comprehensive analyses to evaluate the impact of outages, performing:

- Load flow analysis to identify potential bottlenecks.
- Stability assessments to evaluate transient and dynamic stability.
- Contingency analysis to address potential system disturbances.

13.2.2 Capacity calculation

GCCIA employs a combination of operational studies and system modelling to calculate and validate transfer capacities:

- Network modelling: GCCIA uses Power System Simulator for Engineering (PSS®E) to model the entire interconnected grid. This simulation tool assists in assessing various operational scenarios and determining the maximum transfer capabilities between member states.
- Operational studies: GCCIA conducts load flow, short circuit, transient, and dynamic stability assessments to evaluate the performance of the interconnected system under different conditions. These studies help identify potential bottlenecks and ensure that the system can handle the desired transfer capacities without compromising stability.
- Transfer stability limits: studies are performed to determine the transfer stability limits between member states. These limits define the maximum amount of power that can be transferred without causing system instability or cascading failures.
- Short circuit analysis: short circuit studies are conducted to understand the fault levels and ensure that protection systems are adequately designed to handle potential faults without damaging equipment or compromising system integrity.
- GCCIA performs various engineering studies (contingency analysis) related to system performance, including:
- Impact of critical outages: analysing the impact of critical outages and determining the

required availability and reserves to ensure reliability and optimisation of the combined system.

- Contingency planning: developing contingency plans incorporating optimum system configurations and preventive/corrective actions to maintain system stability during emergencies.

In addition, oscillation and dynamic security assessment is performed using small signal stability analyses to assess the system's ability to dampen oscillations and maintain dynamic stability during disturbances. This ensures that the system can return to stable operating condition after a disturbance.

13.3 ENTSO-E – European Network of Transmission System Operator for Electricity

As part of the EU's Third Legislative Package in the field of energy, Regulation (EC) No 714/2009 sets out the rules governing access to the network for cross-border exchanges in electricity, with a view to ensuring the proper functioning of the EU's internal electricity market. It established the European Network of Transmission System Operators for Electricity (ENTSO-E) which, together with the Agency for the Cooperation of Energy Regulators (ACER), develops European network codes and guidelines, i.e. the rules for the operation of the electricity and gas sectors, which are then adopted by the European Commission. These rules seek to ensure that Europe's energy transmission systems meet the goals of security of supply, increased competitiveness and affordable energy.

The European Network of Transmission System Operators for Electricity (ENTSO-E) has played a pivotal role in standardising and enhancing these processes across the continent.

Network codes and guidelines

The development of network codes and guidelines was identified as a crucial element in completing the internal energy market under the Third Energy Package. These codes are a formalised, detailed set of rules driving the harmonisation of formerly more nationally orientated electricity markets and regulations.

Eight network codes and guidelines came out of the co-creation process. These eight regulations can be subdivided into three groups, as shown in Table 13.4.

Market codes	The capacity allocation and congestion management guideline (CACM)
	The forward capacity allocation guidelines (FCA)
	The electricity balancing guideline (EBGL)
Connection codes	The network code on requirements for grid connection of generators (RfG NC)
	The demand connection network code (DCC)
	The requirements for grid connection of high voltage direct current systems and direct current-connected power park modules network code (HVDC NC)
Operation codes	The electricity transmission system operation guideline (SOGL)
	The electricity emergency and restoration network code (ER)

Table 13.4 ENTSO-E regulation grouping

13.3.1 EU market organisation

Electricity is not only a matter of active energy flows. Transmission capacity and flexibility are two other pillars of the utilities industry. They are also scarce resources and should be priced accordingly. Flexibility refers the ability to change the generation/consumption⁵ of electricity after short notice and this is what has value. Accordingly, energy, transmission, and flexibility are traded in several markets ahead of real-time delivery.

Different markets assign a price to the less visible components of electricity and operate as a sequence. Figure 13.2 shows the successive markets along the three electricity components, along with the relevant guidelines displayed per market.

It should be noted that, alongside trading through organised electricity markets (exchanges), energy can also be traded bilaterally over-the-counter (OTC), whereby market players (electricity generators, retailers, large consumers, and other financial intermediaries) agree on a trade contract by directly interacting with each other. This section focuses on electricity exchanges. Unlike bilateral contracts, products on exchanges are tradable, ensuring transparent prices.

⁵ Electricity demand can vary sharply over time, whilst most power stations can only change output slowly and may take many hours to start up. Furthermore, power stations can fail suddenly. Supply and consumption must match continuously, or the system risks a blackout.

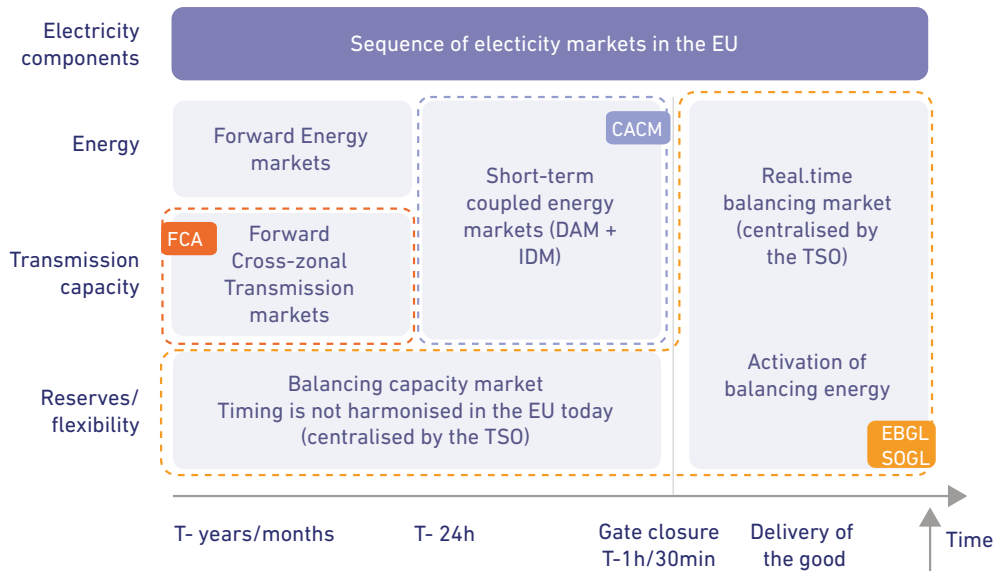


Figure 13.2 The sequence of electricity markets in the EU and related network codes and guidelines

Trading of electricity can begin many years ahead in forward markets, continuing until one day before delivery. The primary purpose of these long-term markets is to allow producers and consumers to hedge. Long-term cross-zonal transmission rights are traded separately from long-term contracts for energy through explicit auctions. Transmission rights allow hedging of price differences between market zones. Long-term cross-zonal transmission capacity markets are the focus of the FCA guidelines.

Closer to delivery, electricity is traded in short-term markets. Short-term markets comprise the day-ahead market, intraday markets, and the real-time balancing market. The day-ahead market, as its name indicates, is an auction held the day before the delivery of electricity. Market players that have not yet committed their electricity supply or demand through bilateral contracts submit their bids to the market operator (MO). The MO clears the auction and produces the first preliminary schedule results for the following day. In most cases today in the EU, transmission capacity is implicitly allocated jointly with energy in the day-ahead market. This process is called market coupling. After the day-ahead market, producers and consumers can change their positions through intraday markets. Intraday markets are organised as continuous markets, with possible complementing auctions. The design rules and methods for integrating day-ahead markets and intraday markets are outlined in the CACM guideline. Intraday trading is possible up to a point in time called the intraday gate closure time (GCT). After the GCT, the final production schedule is determined for all participants, and only the TSO can act to adjust any deviation. The mechanism ensuring that in real-time supply equals demand is called the balancing mechanism.

In real-time, the TSO activates the least-cost resources to address imbalances between generation and consumption. The balancing mechanism is the focus of the Electricity Balancing Guideline (EBGL). The SOGL is also important for this market segment as it provides more

details on sizing or reserves and roles and responsibilities for ensuring real-time balance.

A technical overview of the principles and operational procedures used for outage coordination and capacity calculation within the ENTSO-E framework is provided below.

13.3.2 Outage coordination

Outage coordination in the ENTSO-E framework involves the systematic scheduling of planned maintenance and infrastructure works, ensuring that these activities do not compromise operational security or market functioning. TSOs collaborate through a multilateral coordination platform, exchanging data and assessing security margins under a variety of system states. The coordinated security analysis process, implemented via Regional Security Coordinators (RSCs), supports the detection and mitigation of potential operational risks caused by outages. Outage coordination is governed in Title 3 (from art. 83 to art. 102) of the SOGL.

The outage planning and coordination process consists of the main sub-processes shown in Table 13.5.

<p>Definition of Outage Coordination Regions and relevant assets</p>	<p>In this step, TSOs ensure their participation in the outage planning of a specific outage coordination region. Within the Outage Coordination Region, a Regional Security Coordinator (RSC) is appointed, and his role is to facilitate, coordinate and perform tasks and provide recommendations for the outage planning process. Next, all TSOs shall jointly develop a methodology at least per synchronous area for the assessment of relevant assets (if not available) and use it to define a common single list of relevant assets.</p>
<p>Development and update of availability plans of relevant assets</p>	<p>In this step, it shall first appoint Outage Planning Agents (OPA), with the task of planning the availability status of the relevant grid elements: each TSO shall act as the OPA for each relevant grid element it operates, for all other relevant assets, the owner shall appoint (or act as) the OPA. TSOs and OPAs shall then assess the indicative yearly availability plans and provide availability plans proposals for the relevant assets. Next, all TSOs shall assess whether outage planning incompatibilities (OPI) arise from the availability plans. In case of OPIs, all relevant parties should be informed and find a solution to eliminate OPIs. Once no OPIs remain, the preliminary availability plans can be submitted, validated and then finalized (update in the time between the finalization of the year-ahead outage coordination and before its real-time execution is also possible.)</p>
<p>Execution of availability plans</p>	<p>When it comes to the real-time execution of the availability plans all parties apply the outage planning. Postponement of outages is also possible in case of forced outages or in case a TSO identifies that an outage can lead the transmission system to a not secure state. Due to the change of the network condition forecasted previously.</p>

Table 13.5 Outage planning sub-processes

To achieve regional coordination, all TSOs of an outage coordination region shall jointly develop a regional coordination operational procedure, establishing operational aspects for the implementation of the outage coordination in each region. This includes:

- Frequency, scope and type of coordination for, at least, the year-ahead and week-ahead timeframes .
- Practical arrangements for the provision of the year-ahead relevant grid element availability plans by all TSOs within the outage coordination region.

The following sections set out the activities carried out in each sub-process.

13.3.2.1 Definition of outage coordination regions and relevant assets

To initiate the outage planning and coordination within an outage coordination region, all parties involved must first define the relevant assets to be included. The relevant activities are summarised in the following table.

Activity	Description
<p>Definition of Outage Coordination Regions and Regional Security Coordinators (SOGL art.80)</p>	<p>All TSOs of each capacity calculation region jointly set up a regional security coordinator and establish rules governing its operations or appoint another regional security coordinator to perform a series of tasks, among which the regional outage coordination. Next, the outage coordination regions are defined. In principle, the outage coordination regions within which the TSOs proceed to outage coordination are at least equal to the capacity calculation regions.</p>
<p>Provision of a single list of relevant assets (SOGL art. 85, 87)</p>	<p>TSOs apply the commonly developed methodology for assets relevance evaluation and establish a single list, for each outage coordination region, of relevant assets for the outage coordination. TSOs make available the list of relevant elements of each outage coordination region on the ENTSO for Electricity operational planning data environment (OPDE) and notify at the same time their national regulatory authorities (NRAs). In addition, TSOs also inform all the owners of the elements in the list.</p>
<p>Update of single list of relevant assets (SOGL art. 86, 88)</p>	<p>Before 1 July of each calendar year, all TSOs of each outage coordination region jointly reassess, based on the established methodology, the relevance for the outage coordination of grid elements located in a transmission system and make the updated list available in the ENTSO for Electricity operational planning data environment and inform all the involved parties.</p>

Table 13.6 Outage coordination activities

13.3.2.2 Development and update of availability plans of relevant assets

Following the identification of the relevant elements in the outage planning and coordination process of an outage coordination region, the availability plans of all the relevant assets must be submitted to the respective TSO(s) of the outage coordination region. The goal is to define the availability plans of all the relevant elements considered in the outage planning and coordination for each outage coordination region. The actions to be taken are summarised in Table 13.7.

Activity	Description
Appointment of outage planning agents (SOGL art.89)	Each TSO acts as the outage planning agent for each relevant grid element it operates. For all other relevant assets, the owner appoints, or acts as, the outage planning agent for the relevant assets concerned and informs the respective TSO about that appointment.
Assessment of Long-Term Indicative Plans (SOGL art.93)	Two years before the start of any year-ahead outage coordination, each TSO assesses the corresponding indicative availability plans for internal relevant assets, provided by the outage planning agents, and provides its preliminary comments including any detected outage planning incompatibilities, to all affected outage planning agents. Each TSO carries out the assessment every 12 months until the start of the year-ahead outage coordination.
Provision of year-ahead availability plan proposals (SOGL art.94)	<p>Before 1 August of each calendar year, the outage planning submits to the TSO(s) taking part in an outage coordination region an availability plan covering the following calendar year for each of its relevant assets.</p> <p>In the period between 1 August and 1 December of each calendar year, the outage planning agent has the right to request the TSO(s) to amend the availability plan submitted. The TSO(s) examine the requests for amendment after the year-ahead outage coordination has been finalized respecting the order in which the amendment requests were received.</p>
Assessment of the availability plans for Outage Planning Incompatibilities (SOGL art.95,96)	<p>Each TSO assesses on a year-ahead timeframe whether outage planning incompatibility arises from the availability plans. When a TSO detects outage planning incompatibilities, it performs the following actions:</p> <ul style="list-style-type: none"> • inform each affected outage planning agent of the conditions it shall fulfil to mitigate the detected outage planning incompatibilities. • the TSO may request that one or more outage planning agents submit an alternative availability plan fulfilling the above conditions. • the TSO repeats the assessment to determine whether any outage planning incompatibilities remain. <p>Following the TSO requests, if the outage planning agent fails to submit an alternative availability plan aimed at mitigating all outage planning incompatibilities, the TSO develop an alternative availability plan which:</p> <ul style="list-style-type: none"> • considers the impact reported by the affected outage planning agents • limits the changes in the alternative availability plan to what is strictly necessary to mitigate the outage planning incompatibilities. • notifies its National Regulatory Authority, and the affected outage planning agents about the alternative availability plan, including the reasons for developing it, as well as the impact reported by the affected outage planning agents.

<p>Provision of preliminary year-ahead availability plans (SOGL art.97)</p>	<p>Before 1 November of each calendar year, each TSO provides to all other TSOs, via the ENTSO for Electricity operational planning data environment, the preliminary year-ahead availability plans for the following calendar year relative to all the internal relevant assets.</p>
<p>Validation of year-ahead availability plans (SOGL art.80,98)</p>	<p>Each TSO analyses whether any outage planning incompatibility arises when considering all the preliminary availability plans on a year-ahead timeframe. If a TSO detects outage planning incompatibility (OPI), the involved TSOs of the outage coordination region(s) concerned jointly identify a solution in coordination with the concerned outage planning agents using the means at their disposal, while respecting to the extent possible the availability plans submitted by other outage planning agents.</p> <p>In case solution is identified, all TSOs of the concerned outage coordination region(s) update and validate the year-ahead availability plans for all relevant assets.</p> <p>In case no solution is identified, each TSO takes the following actions:</p> <ul style="list-style-type: none"> • forces to “available” all the “unavailable” or “testing” statuses for the internal relevant assets involved in an outage planning incompatibility during the period concerned • notifies the actions taken to the relevant national regulatory authorities, and the affected outage planning agents of the actions taken including the rationale for such actions, the impact reported by affected outage planning agents. <p>Consequently, all TSOs of the concerned outage coordination regions update and validate the year-ahead availability plans for all relevant assets</p>
<p>Final year-ahead availability plans (SOGL art.99)</p>	<p>Before 1 December of each calendar year, each TSO:</p> <ul style="list-style-type: none"> • finalizes the year-ahead outage coordination of internal relevant assets • finalizes the year-ahead availability plans for internal relevant assets and upload them on the ENTSO for Electricity operational planning data environment.
<p>Updates to the final year-ahead availability plans (SOGL art.100)</p>	<p>The outage planning agent and/or a TSO can launch a procedure for the amendment of the final year-ahead availability plan (for the assets they act as outage planning agent) in the time between the finalization of the year-ahead outage coordination and before its real-time execution.</p> <p>In case of a request for amendment by the outage planning agent, the following actions take place:</p> <ul style="list-style-type: none"> • the recipient TSO acknowledges the request and assesses as soon as reasonably practicable whether the amendment leads to outage planning incompatibilities. • in case outage planning incompatibility is detected, the involved TSOs of the outage coordination region jointly identify a solution in coordination with the outage planning agents concerned and using the means at their disposal. • in case no outage planning incompatibility has been detected or if no outage planning incompatibility remains after coordination among the relevant parties, the recipient TSO validates the requested amendment, and the TSOs concerned consequently notify all affected parties, and update the final year-ahead availability plan on the ENTSO for Electricity operational planning data environment. • in case no solution is found for outage planning incompatibilities the receiving TSO rejects the requested amendment.

	<p>In case of a request for amendment by a TSO, the following actions take place:</p> <ul style="list-style-type: none"> • the requesting TSO prepares a proposal for amendment to the year-ahead availability plan, including an assessment of whether it could lead to outage planning incompatibilities and submits its proposal to all other TSOs of its outage coordination region(s). • in case outage planning incompatibilities are detected, the involved TSOs of the outage coordination region jointly identify a solution in coordination with the concerned outage planning agents and using the means at their disposal. • in case no outage planning incompatibility has been detected or if a solution to an outage planning incompatibility is found, the concerned TSOs validate the requested amendment and consequently they notify all affected parties and update the final year-ahead availability plan on the ENTSO for Electricity operational planning data environment. • In case no solution to outage planning incompatibilities is found, the requesting TSO retracts the procedure for amendment.
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Table 13.7 Availability plan actions

13.3.2.3 Execution of availability plans

In this final step, the goal is to execute the availability plans of all the relevant elements considered in the outage planning and coordination for each outage coordination region. All details regarding the execution of availability plans are taken directly from SOGL Title 3, Chapter 3; TSOs are responsible for agreeing a common interpretation and level of detail for the required activities. The actions to be taken are summarised in Table 16.8.

Activity	Description
<p>Information about the elements with “testing” status (SOGL art.101)</p>	<p>The outage planning agent of a relevant asset the availability status of which has been declared as “testing” provides the TSO within one month before the start of the “testing” status with:</p> <ul style="list-style-type: none"> • a detailed test plan • an indicative generation or consumption schedule in case of power generating module or relevant demand facility • changes to the topology of the transmission system <p>In case this relevant asset is a relevant grid element interconnecting two or more control areas, the TSOs of the concerned control areas agree on the information to be provided.</p>
<p>Handling of Forced Outages (SOGL art.102)</p>	<p>The outage planning agent notifies the forced outage of one or more of its relevant assets to the TSO as soon as possible following the start of the forced outage. When notifying the forced outage, the outage planning agent provides the following information:</p> <ul style="list-style-type: none"> • the reason for the forced outage • the expected duration of the forced outage • where applicable, the impact of the forced outage on the availability status of other relevant assets for which it is the outage planning agent. <p>In case a TSO detects that one or several forced outages could lead the transmission system out of the normal state, it informs the affected outage planning agent(s) about the time-limit at which operational security can no longer be maintained unless their relevant asset(s) in forced outage returns to “available”</p>

	<p>status. The outage planning agents inform the TSO whether they can respect that time limit and provide reasoned justifications where they are unable to respect that time limit.</p> <p>In case of any amendments to the availability plan due to forced outages, the TSO concerned updates the ENTSO for Electricity operational planning data environment (OPDE) with the most recent information.</p>
<p>Real-time execution of the availability plans (SOGI art.103)</p>	<p>When it comes to the real-time execution of the availability plans all parties make sure that the availability plans of their assets are fulfilled. However, in case a TSO identifies that executing an "unavailable" or "testing" status of a relevant asset leads or could lead the transmission system to go out of normal state, it instructs the owner of the relevant asset when it is connected to the transmission system to delay the execution of that "unavailable" or "testing" status of that relevant asset according to its instructions and to the extent possible while respecting the technical and safety limits.</p>

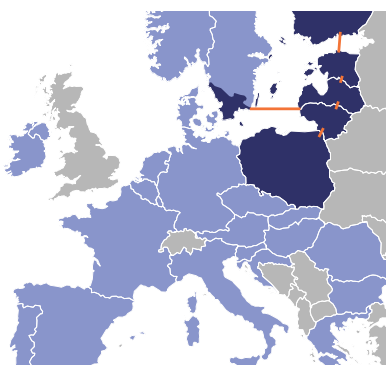
Table 13.8 Availability plan execution actions

13.3.3.3 Capacity calculation regions and regional security coordinators

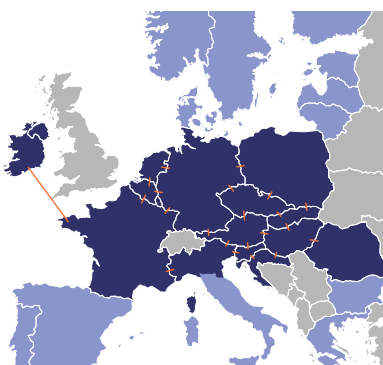
To ensure that cross-zonal transmission capacity calculation is reliable, and that optimal capacity is made available to the market, regional coordination between the TSOs is required. This reflects the highly interdependent nature of electricity flows in a meshed network.

To enable coordination, Art. 15 of the CACM Guideline requires Capacity Calculation Regions (CCRs) to be determined. A CCR comprises a set of bidding zone borders and is defined as the geographic area in which coordinated capacity calculation is applied. The current capacity calculation regions are:

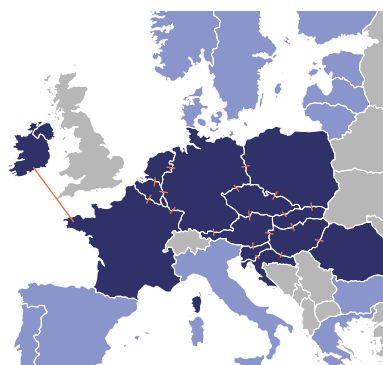
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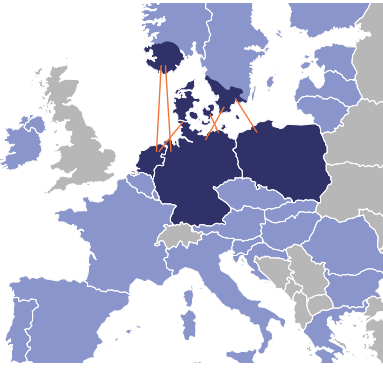
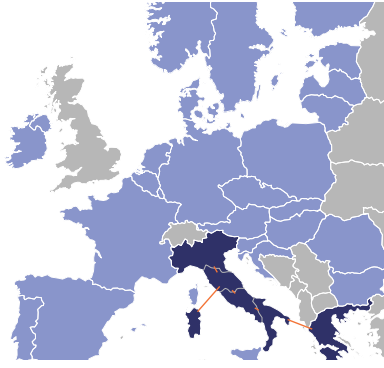
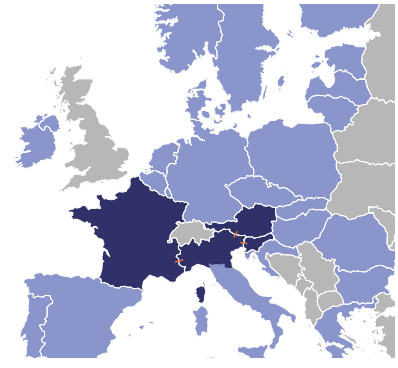
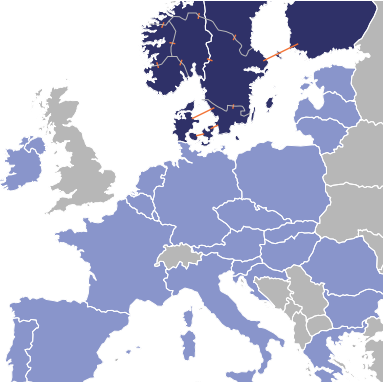
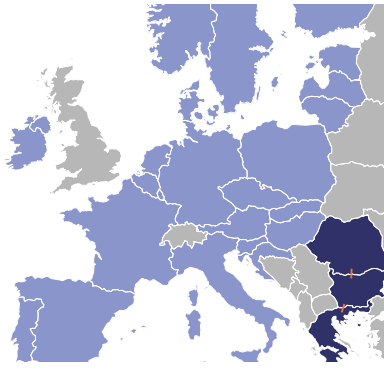
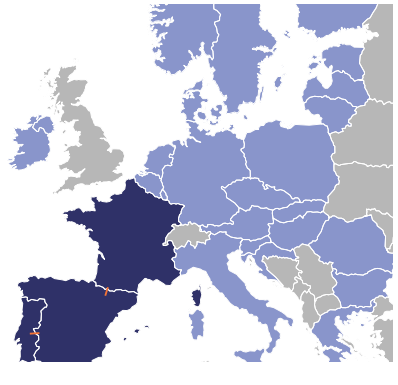


Central Europe



Core



Hansa**Greece-Italy (GRIT)****Italy North****Nordic****South East Europe****South West Europe****Figure 13.3 ENTSO-E capacity calculation regions**

The CACM also requires all TSOs in each CCR to jointly establish coordinated capacity calculators and rules governing their operations. Coordinated capacity calculators are responsible for calculating transmission capacity at a regional level or above. CCRs are relevant across all market codes (FCA, CACM and EBGL) and in SOGL. In all timeframes, capacity calculation shall be carried out using a harmonised methodology per CCR. The coordinated capacity calculator shall receive the necessary input from all relevant TSOs to perform the computation of available capacity (for long-term, the day-ahead, intraday, and balancing markets) at all bidding zone borders within its CCR. A crucial tool created for this purpose is the Common Grid Model, the principles of which are described in both the FCA and CACM guidelines.

Closely associated with CCRs are regional coordination centres (RCCs), established under EU law by the SOGL. The SOGL requires that each control area is covered by at least one RCC. RCCs are owned or controlled by TSOs and perform tasks related to TSO regional coordination. The first RCCs were set up as voluntary initiatives (RCCIs) by TSOs from 2008, with CORESO (based in Brussels) and TSCNET Services (Munich) as pioneers in Continental Europe. In 2015, an RCC was created in South East Europe (SEE) in Belgrade. In 2016, the Nordic TSOs started discussing the creation of a Nordic RCC.

Regional coordination centres issue recommendations to the TSOs of the capacity calculation

region(s) for which they are appointed. TSOs should then individually decide whether to follow the recommendations, whilst retaining ultimate responsibility for maintaining operational security of their control areas. Coordinated capacity calculation is also one of the tasks of the Coordination Centres. For a capacity calculation region with more than one established RCC, only one RCC is responsible for assuming the role of coordinated capacity calculator at any given time. Other RCCs with responsibilities within that coordinated capacity calculation region can assume this role at any time, as a back-up. This arrangement ensures consistency between coordinated capacity calculation and coordinated security assessment.

13.3.3.1 Capacity calculation methodology

Three key network codes outline specific requirements and obligations on system operators in relation to coordinated capacity calculation:

- Commission Regulation (EU) 2015/1222 of 24 July 2015 on establishing a guideline on capacity allocation and congestion management (CACM), which outlines the following requirements:
 - Development of a common capacity calculation methodology, including details of any allocation constraints.
 - Establishment of a coordinated capacity calculator (CCC).
 - Establishment of a common coordinated redispatching and countertrading methodology.
- Commission Regulation (EU) 2016/1719 of 26 September 2016 on establishing guidelines on forward capacity allocation (FCA), which outlines the following requirements:
 - Development of a common capacity calculation methodology for long-term allocations.
 - Use of the coordinated capacity calculator established under CACM.
 - Develop a methodology for splitting long-term cross-zonal capacity (CZC).
- Commission Regulation (EU) 2017/2195 of 23 November 2017 on establishing a guideline on electricity balancing (EB GL), which outlines the following requirements:
 - Development of a common capacity calculation methodology within the balancing timeframes for the exchange of balancing energy or for operating the imbalance netting process.

The network codes require the CZC calculation to be carried out by the appointed coordinated capacity calculator for each CCR, in accordance with the relevant coordinated capacity calculation methodology. The coordinated capacity calculation (CCC) process uses the technical parameters of the network (such as a common grid model, contingencies, shift keys, etc.) as inputs. Coordinated capacity calculation should be efficient, transparent, and well coordinated among system operators and Regional Security Coordinators (RSCs). CZC can be calculated either with a flow-based or net transfer capacity approach.

In the capacity calculation process, several stakeholders perform specific roles (Table 13.9).

System Operator	Within coordinated capacity calculation process, SO provides most of the needed inputs to perform the coordinated capacity calculation and validates the results provided by the Coordinated Capacity Calculator. SO also provides the long-term capacity allocation results to the Transmission Capacity Allocator (TCA) for publication purposes.
Coordinated Capacity Calculator (CCC)	The CCC calculates the transmission capacity between the bidding zones of his Capacity Calculation Region (CCR) based on the inputs received from SOs. The CCC submits Cross-zonal Capacity (CZC) to the SO within its CCR for validation and delivery for allocating capacity.
Merging Agent	The Merging Agent is responsible for gathering the Individual Grid Models (IGMs) from SOs and merging them into a Common Grid Model (CGM). The Merging Agent provides the CGM to the Coordinated Capacity Calculator, who uses it as an input to calculate the CZC.
Transmission Capacity Allocator (TCA)	TCA manages the allocation of available transmission capacity for a bidding zone border. In coordinated capacity calculation process, TCA receives the long-term CZC results. These results are used for long-term capacity allocation.
NEMO	The NEMO performs tasks related to single day-ahead or single intraday coupling. Within coordinated capacity calculation process, NEMO receives the day-ahead and intraday CZC results. These results are used for day-ahead/intraday capacity allocation.

Table 13.9 Capacity calculation stakeholders

The capacity calculation process consists of the main sub-processes shown in Table 13.10.

Individual grid model	SO provides its own IGM to the Merging agent. Merging agent merges all the IGMs into one CGM.
Common grid model	Merging agent provides the CGM to the Coordinate Capacity Calculator.
Network constraints and remedial actions	SO provides a list of the network constraints and remedial actions to be considered during the coordinated capacity calculation. CCC collects and validates them and might propose changes if some inconsistencies are found.
Generation and load shift keys	SOs provide generation and load shift keys (GLSKs) to the CCC, which describe the participation of generation or load units or their respective scheduling area to the net position shift of the whole area. CCC collects and validates them and proposes changes if some inconsistencies are found.

	<p>CCC uses GLSK as an input to change the net position of a given bidding zone into injection or consumption increases or decreases in the CGM.</p> <p>Then, the CCC perform business checks on the input provided by SOs. These checks consist in comparing the data provided with the Common Grid Model to ensure consistency in the characteristics of the network elements. For example, the input provided by SOs can be compared with the information contained in the CGM to make sure that all the network elements to be monitored exist in the CGM, or that all the generation units on which generation shift keys are provided can be operated according to the CGM. In case of a failure of this business checks on some files, the sending SOs are notified, and can potentially provide a new version of these inputs.</p>
Additional constraints	<p>SO provides additional constraints for the coordinated capacity calculation (i.e. constraints which are not directly related to network elements to be monitored) to the CCC, as well as the capacity which was already allocated at previous timeframes. This allows the CCC to make sure that the calculated capacity is higher than the already allocated capacity during the calculation step.</p>
Already Allocated Capacity	<p>SO and CCC must consider the CZC that has been already allocated in a previous timeframe (If there has been an allocation previously).</p>
Cross-zonal capacity	<p>The CCC then performs the merging of all the individual input from SOs to get merged network constraint situations to be studied and merged GLSKs overall CCR.</p> <p>Depending on the CCRs and the timeframe, a remedial action optimization step can also be run by the CCC, consisting in finding the optimal remedial actions to be applied in all the network constraint situations studied, amongst the remedial actions provided by SOs. If a remedial action optimization is run, the output, consisting in the remedial actions which are applied in each constraint situation, is forwarded to SOs.</p> <p>The coordinated capacity calculation process is then run to maximize the exchanges on the borders of the CCR while considering the parameters and constraints provided as input. The output of this calculation is designated as the proposed CZC. If the coordinated capacity calculation process is NTC-based, the CZCs consist of capacity values (TTCs, NTCs, or ATCs) on the borders of the CCR, associated with the constraint situations which limited the capacity. If the coordinated capacity calculation process is flow-based, the CZCs consist of a flow-based domain. At that stage, the CZCs are “proposed” because they still need to be validated by SOs.</p>
Critical network elements	<p>Once the calculation is performed, CCC provides the SO with a list of limiting critical network elements for internal processes. The critical network elements enable to define the NTC. The critical network elements may be provided, complemented by flow-based parameters in case that flow-based calculation is performed. Those flow-based parameters will include the influence of the critical network elements on the market coupling process.</p>
Validation and deliverable of the cross-zonal capacity	<p>SOs validate the proposed CZCs they receive to make sure they are in line with their network security. SOs can either accept the capacity, propose a reduction of the capacity if the proposed capacity does not ensure internal grid security, or propose an increase of the capacity in case internal studies have shown that additional capacity can be provided to the market without jeopardizing grid security. In case a SO proposes a reduction of the capacity, it must justify it by</p>

	<p>providing additional constraints leading to this capacity reduction. In case SO proposes an increase of the capacity, the coordinated capacity calculation step is run again, and another capacity validation is performed if the duration of these steps respects the deadlines defined in the process.</p> <p>Once SOs have validated the CZC, the CCC concatenates the validated CZC and sends to SOs the final CZCs which are provided to the market. The final CZCs consider the potential additional constraints provided by SOs.</p>
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Table 13.10 Capacity calculation sub-processes

The final CZCs are published by the CCC to NEMOs in the case of a day-ahead or an intraday process, or by SOs to the TCA for long-term processes. The CCC may also provide allocation constraints (additional constraints on the capacity provided to the market) alongside the validated CZCs.

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