



TwinEU – New approaches to the strategic planning and operational management of the future European power systems and markets

Deliverable No: D9.2

Work package: WP9

Official delivery date: 30/09/2026

Actual delivery date: 02/10/2026

Dissemination level: Public



**Co-funded by
the European Union**

Project: 101136119 | HORIZON-CL5-2023-D3-01 | www.twineu.net

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Version	Date	Author(s)	Notes
V0.1	24/09/2026	as per list above	Version submitted for review
V0.2	30/09/2026	Léo Rossignol, Léo Quignon, Thomas Brouhard	Updated after review
V1	01/10/2026		Ready for submission

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List of Abbreviations and Acronyms

Acronym	Meaning
ACER	Agency for the Cooperation of Energy Regulators
aFRR	automatic Frequency Restoration Reserve
AI	Artificial Intelligence
API	Application Programming Interface
ATC	Available Transfer Capacity
BCR	Benefit-Cost Ratio
BESS	Battery Energy Storage System
CBA	Cost-Benefit Analysis
CEER	Council of European Energy Regulators
CEM	Common Evaluation Methodology
CGMES	Common Grid Model Exchange Standard
CIM	Common Information Model
CNEC	Critical Network Element(s) with Contingency
CO ₂	Carbon Dioxide
DASSA	Day-Ahead System Services Auction
DC	Dynamic Containment (GB frequency response product)
DER	Distributed Energy Resource
DLR	Dynamic Line Rating
DM	Dynamic Moderation (GB frequency response product)
DNDP	Distribution Network Development Plan
DR	Dynamic Regulation (GB frequency response product)
DS3	Delivering a Secure, Sustainable Electricity System (Ireland/Northern Ireland system services programme)
DSO	Distribution System Operator
DT	Digital Twin
EDM	Equivalent Dynamic Model
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
EV	Electric Vehicle

FACTS	Flexible AC Transmission System
FCA	Flexible Connection Agreement
FCR	Frequency Containment Reserve
FFR	Fast Frequency Response
FSP	Flexibility Service Provider
GIS	Geographic Information System
GW / GWh	Gigawatt / Gigawatt-hour
HDR	Health Discount Rate
HV	High Voltage
HVDC	High-Voltage Direct Current
IRR	Internal Rate of Return
JRC	Joint Research Centre (European Commission)
KPI	Key Performance Indicator
LFM	Local Flexibility Market
LV	Low Voltage
mFRR	manual Frequency Restoration Reserve
MTU	Market Time Unit
MV	Medium Voltage
MW / MWh	Megawatt / Megawatt-hour
N-1	single-contingency reliability criterion (loss of one network element)
NDP	Network Development Plan
NECP	National Energy and Climate Plan
NPV	Net Present Value
NRA	National Regulatory Authority(ies)
NTC	Net Transfer Capacity
OCGT	Open-Cycle Gas Turbine
PHS	Pumped Hydro Storage
PTDF	Power Transfer Distribution Factor
PV	Photovoltaic
RCC	Regional Coordination Centre
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency

RES	Renewable Energy Sources
SCADA	Supervisory Control and Data Acquisition
SLR	Static Line Rating
STPR	Social Time Preference Rate
TIDE	Testo Integrato del Dispacciamento Elettrico (Italy's integrated electricity dispatching regulatory framework)
TIM	Totex Incentive Mechanism
TSO	Transmission System Operator
TWh	Terawatt-hour
TYNDP	Ten-Year Network Development Plan
V2G	Vehicle-to-Grid
VAL	Valor Atual Líquido (Net Present Value; used interchangeably with NPV in the E-REDES methodology)
VOLL	Value of Lost Load
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital

1 Key outcomes at a glance

TwinEU develops and demonstrates digital twins (DTs) for the future pan-European power system. Through 8 pilots across Europe, the project has produced 50 use cases, covering topics from forecasting and grid monitoring to flexibility markets and frequency support. Work Package 9 builds on these demonstrations to chart a pathway towards wider adoption of DTs across the European grid, looking at both what stands in the way of deployment and what value they could bring to system planning and operations.

This deliverable reports on two complementary perspectives. Task 9.4 examines the new services and business models that DTs could enable, and the conditions required for them to move from pilot to routine operation. Task 9.5 assesses the impact that the approaches demonstrated in TwinEU could have on the pan-European system, should they become widely adopted, with a focus on system costs and welfare. The key outcomes below bring both perspectives together.

Key messages

1. **DTs aim mainly to shift system operation from static, centralised and sequential arrangements to dynamic, federated and probabilistic coordination.** They create value through market-facing services and internal operational improvements. All four service clusters depicted in T9.4 depend on trusted data exchange, interoperable models and a credible route from analytical output to an operational or market action (T9.4, Sections 3.3.1–3.3.4 and 3.6.1).
2. **The main adoption barrier is the incomplete end-to-end operating chain, not the technology.** Gaps concern regulatory recognition of probabilistic or automated outputs, cost recovery, liability, data rights, interoperability, cybersecurity, decision rights and lifecycle funding. Cross-border use also requires common models, risk thresholds and cost-allocation principles (T9.4, Sections 3.4.1–3.4.4 and 3.6.1).
3. **Adoption should be staged and conditional.** The pathway runs from offline validation to shadow operation, supervised use and bounded automation. Replication follows four stages (evidence consolidation, operational incubation, controlled deployment, regional scaling). Scaling depends on demonstrated security and value (T9.4, Sections 3.5.1 and 3.5.3–3.5.4).
4. **Quantified benefits are real but moderate at EU scale.** Better renewable forecasts reduce system costs by about 743 M€/year (-1.1%). Dynamic Line Rating (DLR) delivers 46.6 to 225.5 M€/year for a 2-10% flow-based margin correction. Cutting planned maintenance from 5 to 4 days saves about 60 M€/year (T9.5, Sections 4.2.2, 4.4.3 and 4.5.3).
5. **Benefits are concentrated both in terms of actors and countries, and not aligned with who bears the cost and risk (T9.4, T9.5, Sections 3.4.1, 3.4.4, 4.2.2 and 4.4.3).**
 - Three countries out of 35 explain 80% of the forecast gains in the T9.5 Forecast Accuracy theme (Poland about 70%). Seven explain 80% of the DLR gains, mainly on the AT-DE and AT-HU corridors.
 - For DLR, the value shows up as production-cost savings for market participants, while total congestion rent falls slightly (-2.9 M€ at 2%).

- T9.4 identifies this misalignment as a barrier and calls for benefit-sharing and cross-TSO recognition of model versions and fallbacks. T9.5 shows why: DLR should be deployed first where constraints actually bind, and judged on several indicators, since congestion hours rise (+320 h at 2%) while welfare improves.
 - The concentration of benefits points to a targeted first roll-out of DT technologies in the countries and actors that gain most, as a bridge between pilots and system-wide adoption. This reinforces the staged adoption pathway set out in Key Message 3.
6. **FFR shows that the challenge is assured delivery, not product creation (T9.4, T9.5, Sections 3.5.1 and 0–4.8.7).**
- Four operational products were reviewed (DS3, Nordic, Great Britain, Italy). Capacity shrinks between qualification and operation (Italy: 1,327 MW qualified, 249.9 MW awarded, about 170 MW operating). Batteries supply 96.6–98.5% of awarded capacity in Great Britain.
 - No market publishes availability versus schedule or response quality. This supports the T9.4 requirements: assurance before activation, continuous portfolio monitoring, automated settlement, and procurement sized on an assessed system need (T9.4, T9.5).

Values created by service clusters (T9.4)

Table 1: Value and adoption conditions by service cluster (T9.4)

Service cluster	Value created	Key conditions for adoption
Market surveillance and integrity	Earlier, context-aware detection of abnormal participation	Joint triage function; explainable alerts; urgent protection separated from formal enforcement
Distributed-resource coordination and flexibility	Better observability, portfolio qualification, local deliverability checks, coordinated activation	Common asset registry; TSO–DSO feasibility check; priority rules for overlapping commitments; harmonised baselines
Transmission-capacity assessment (DLR, probabilistic)	Additional capacity, anticipation of congestion and uncertainty	Integration into existing security analysis; shared model version and fallback among neighbouring TSOs; automatic reversion to static limits
Fast Frequency Response	Fast response from batteries, controllable demand, EVs and inverter-based generation	Assurance completed before activation; technology-neutral product; edge processing; dynamic sizing

Quantified system impacts (T9.5)

Table 2: Headline results by transversal theme (T9.5)

Theme	Lever tested	Headline result	Evidence basis
Forecast Accuracy	Solar/wind forecast error reduction in all zones	-743 M€/yr (-1.1%), -1.0 Mt CO ₂ , -1.4 TWh curtailment	Pilot KPI (BG02/BG03), extrapolated by simulation
Dynamic Line Rating	Flow-based margin relaxed by 2 to 10%	46.6 to 225.5 M€/yr, near-linear; at 10%: -0.88 Mt CO ₂ , -1.64 TWh curtailment	Pilot HU02 confirms concentration on few binding constraints; margin levels are simulation sensitivities
Grid Monitoring	Planned maintenance of 4 to 9 days	5→4 days: -60 M€/yr; 5→9 days: +220 M€/yr; no robust effect on loss-of-load hours	Generic hypothesis (no pilot KPI); simulation
Grid Hosting, Strategic Planning, LFM, FFR	Benchmarks of European practice, dispatch simulations with constraints	Enedis REFLEX: about 250 M€ net collective benefit; 17 LFM initiatives reviewed	Literature and market benchmarks, not simulation

Adoption priorities

1. Prior to wide adoption, run each selected service through shadow mode, supervised use and bounded automation, with explicit readiness gates.
2. Name an accountable service owner and a cross-organisational responsibility matrix before live operation.
3. Make data and model assurance a continuous process (quality, provenance, versioning, drift detection, fallback).
4. Give regulators a workable route: assurance classes, sandboxes with a path to permanent approval, cost recovery, benefit-sharing where national investments create regional welfare.
5. Deploy first where value concentrates: binding corridors for DLR, high-exposure countries for forecasting, locations behind actual constraints for flexibility.

2 Introduction

2.1 General Introduction / narrative framework

The TwinEU project brings together grid and market operators, technology providers and research centres from across Europe to develop and demonstrate digital twin solutions for the future pan-European power system. Through eight demonstration pilots, TwinEU has produced a wide and heterogeneous set of use cases, covering topics ranging from forecasting and grid monitoring to flexibility markets and frequency support, each illustrating how digital twin technologies can support the operation and planning of the electricity grid.

Work Package 9 builds on these demonstrations to chart a pathway towards the wider adoption of digital twins across the pan-European grid, examining the barriers to their deployment and the positive impact they could have on system planning and operations. This deliverable reports on two of the tasks contributing to this objective. Task 9.4 explores the new services and business models that digital twins could enable or require, identifying the key stakeholders involved and the resources needed to support them. Task 9.5 is devoted to assessing the impact of the approaches identified across the TwinEU demonstrations, should they become widely adopted, on the strategic planning and operational management of the future European power system and markets.

2.2 Task-specific goals

2.2.1 Task 9.4

Task 9.4 assesses how the TwinEU federated Digital Twin ecosystem can enable new business models and operational services for the European electricity system. It translates pilot results into value propositions for Transmission System Operators (TSOs), Distribution System Operators (DSOs), market operators, flexibility providers, regulators and technology partners. The task identifies five business cases across four service clusters: abnormal market participation detection, distributed-resource monitoring and flexibility activation, more efficient use of transmission infrastructure (advanced operational assessment and probabilistic cross-border capacity), and Fast Frequency Response for low-inertia systems.

The analysis finds that the main barrier to adoption is not technology but the incomplete end-to-end operating chain. Gaps include regulatory recognition, cost recovery, liability, data rights, interoperability and cybersecurity. The task therefore recommends a staged pathway, moving from offline validation to shadow operation, supervised use and then bounded automation. This pathway should be supported by robust data and model assurance, proportionate regulation, regulatory sandboxes and common standards, and scaling should depend on proven value and resilience.

2.2.2 Task 9.5

Task 9.5 assesses the impact of TwinEU's digital twin-enabled use cases on the strategic planning and operational management of the pan-European power system. Insights from the demonstrators are synthesised into seven transversal themes — Forecast Accuracy, Grid Hosting Capacities, Dynamic Line

Rating, Grid Monitoring, Strategic Planning, Local Flexibility Markets, and Fast-Frequency Response — selected for their relevance and replicability at European scale.

For each theme, pan-European hourly simulations quantify system-level effects, primarily in terms of welfare and system costs, complemented by indicators such as curtailment and security of supply. Findings are then translated into recommendations for key stakeholders (market participants, TSOs, RCCs, ACER), notably on integrating distributed flexibility into scenario development and CBA methodologies, and on technologies such as PSTs in the SDAC market clearing process.

3 Creation of new services and business models (T9.4)

3.1 Introduction

3.1.1 Context of the task

This project aims to explore innovative approaches to sustainable urban development. The European Union, under Horizon Europe, has identified the need for sustainable urbanization as a key challenge.

In the context of the TwinEU Horizon project, a “new business case” or “service” refers to an innovative application of digital twin technologies that creates measurable value for power system stakeholders, particularly TSOs, DSOs, and grid users. These business cases are not limited to market-facing services, but also include internal operational improvements enabled by enhanced data, modelling, and decision-support capabilities.

A new business case typically describes a structured use of DT functionalities to address a specific operational, market, or planning challenge. It defines the problem, involved stakeholders, required data and technologies, expected outcomes, and the value generated (e.g. cost savings, improved reliability, increased efficiency, or new revenue streams). In the TwinEU framework, business cases are closely linked to pilot implementations, where solutions are tested in real or near-real environments across different European contexts.

A new service, on the other hand, represents the practical implementation of a business case. It can take the form of an external offering, such as flexibility services for grid users, improved market participation mechanisms, or enhanced transparency tools. Alternatively, it can be an internal service within TSOs or DSOs, such as advanced grid monitoring, predictive maintenance, or automated decision-support processes that improve system operation and planning.

Importantly, in TwinEU, services are enabled by the federation of local digital twins into a broader European architecture. This allows integration of data across system boundaries, improved coordination between stakeholders, and scalability of solutions. As a result, new business cases and services contribute not only to local optimisation, but also to the development of a more resilient, efficient, and interconnected European energy system.

3.1.2 Objectives of this Section

The primary objective of Task 9.4 is to identify and assess new business models and services enabled by the TwinEU federated Digital Twin ecosystem. It translates the project’s technical and pilot developments into structured value propositions for system operators, market actors, flexibility providers, regulators, and technology partners. In doing so, Task 9.4 considers both market-facing opportunities and internal operational services that can improve reliability, efficiency, coordination, and the use of existing grid assets.

More specifically, the Task 9.4 pursues five connected objectives:

- **Establish the baseline.** Analyse existing business models and operational arrangements in power-system operation and planning, market surveillance, distributed-resource utilisation, transmission-capacity management, and frequency-control services.
- **Define TwinEU-enabled opportunities.** Identify the services that emerge from the selected project tasks and pilots, group them into coherent service clusters, map their stakeholders, and explain how Digital Twin capabilities create operational, market, and societal value.
- **Assess deployment conditions.** Examine the regulatory, market, technical, data, organisational, operational, and cross-border barriers that may prevent successful pilot solutions from becoming routine and scalable services.
- **Formulate adoption pathways.** Provide practical recommendations for TSOs, DSOs, market operators, regulators, policy makers, research organisations, standardisation bodies, aggregators, and technology providers.
- **Support exploitation and replication.** Define how project results can be packaged, assured, financed, transferred, and progressively integrated into European operational and market processes.

The scope is organised around five business cases within four service clusters: abnormal market participation detection and protocol activation; distributed-resource monitoring, coordination, and flexibility activation; advanced operational assessment for transmission capacity; probabilistic cross-border capacity calculation and flexibility assessment; and Fast Frequency Response. These cases are linked to the relevant TwinEU pilot tasks and are assessed consistently in terms of users, value creation, data and technology needs, governance, risks, market design, and scalability.

The Task 9.4 does not seek to prescribe one commercial model or a single technical architecture for all European contexts. Instead, it provides a common analytical framework for comparing services that differ in timescale, regulatory setting, data sensitivity, and operational criticality. Its intended outcome is a traceable bridge between TwinEU pilot evidence and the decisions required for adoption: who owns and operates a service, what information and assurance it requires, how benefits and risks are allocated, and which steps are needed to progress from demonstration through controlled deployment to wider replication.

Accordingly, the section is intended to support project partners in consolidating pilot results, operators in evaluating adoption, regulators in identifying enabling conditions, and research and technology organisations in prioritising interoperable and reusable solutions. The objectives are fulfilled progressively across Chapters 3.2 to 3.6, moving from the current-state baseline to new service concepts, barriers, recommendations, and final conclusions.

3.1.3 How to Read this Section

This section follows a progressive logic from the current state of electricity-system business models to practical pathways for the adoption of TwinEU-enabled services. Readers seeking a complete understanding should proceed in sequence, because each chapter provides the basis for the next: the baseline in Chapter 3.2 frames the innovations in Chapter 3.3; the identified innovations are tested against the barriers in Chapter 3.4; and those barriers are translated into recommendations and conclusions in Chapters 3.5 and 3.6.

Chapter 3.2 establishes the analytical baseline. It reviews existing arrangements for power-system operation and planning, market surveillance, the use of distributed resources, transmission-capacity enhancement, and frequency containment and response. This chapter is particularly relevant for readers who need to understand the limitations of current centralised, deterministic, and sequential practices before considering the proposed innovations.

Chapter 3.3 presents the core TwinEU contribution. It identifies the new services and business models enabled by the project, maps the relevant tasks and pilots, identifies key stakeholders, and analyses each service cluster. Readers interested in a specific use case can use the task-by-use-case traceability table in Section 3.3.2 and then move directly to the corresponding stakeholder and business-model subsections.

Chapter 3.4 should be read as the feasibility and adoption assessment. Its sections distinguish regulatory and market barriers from technical and data gaps, organisational and operational challenges, and cross-border coordination issues. The chapter is useful for implementation teams and decision makers who need to identify which non-technical and technical conditions must be resolved before a service can move beyond a pilot.

Chapter 3.5 converts the preceding analysis into action. Sections 3.5.1 and 3.5.2 address system operators and regulatory authorities respectively; Section 3.5.3 sets priorities for research and standardisation; and Section 3.5.4 outlines exploitation and replication. Readers preparing an implementation plan can use these sections as a checklist for service ownership, assurance, market access, interoperability, staged deployment, and benefit measurement.

Chapter 3.6 provides a concise synthesis of the principal findings and recommendations. It can be read independently by senior stakeholders who need the main messages, although the supporting rationale remains in Chapters 3.2–3.5. Three shorter reading paths may also be useful. **Operational and market practitioners** can focus on Chapters 3.2, 3.3, 3.4.2–3.4.4, and 3.5.1. **Regulators and policy makers** can prioritise Chapters 3.3, 3.4.1 and 3.4.4, and 3.5.2. **Research, standards, and exploitation teams** can begin with the service mapping in Chapter 3.3 and continue with Chapters 3.4, 3.5.3, and 3.5.4. Terminology is used consistently throughout: a *business case* describes the value logic and stakeholder arrangement, while a *service* refers to its practical operational or market implementation.

3.2 Analysis of existing business models

The transformation of European power systems, driven by high penetration of renewable energy sources, increased digitalization, and growing system complexity, has exposed clear limitations in traditional business models for system operation, planning, and market participation. Historically, these models have been structured around centralized generation, deterministic planning approaches, and relatively static market mechanisms. However, the emergence of Distributed Energy Resources (DERs), advanced data-driven tools, and new system services is fundamentally reshaping how value is created and captured across the electricity value chain.

In this context, the term *business model* is used in a broad sense, encompassing not only revenue-generating mechanisms, but also the regulatory frameworks, market designs, and operational processes through which system services are procured, delivered, and valued. This reflects the regulated nature of the power system, where value creation is often defined in terms of cost efficiency, system reliability, and overall market performance rather than direct profit maximization.

Within this context, the TwinEU project introduces a range of novel use cases that challenge existing operational and market paradigms. Rather than developing entirely new business models in isolation, these innovations build upon and extend current frameworks in areas such as market surveillance, flexibility utilization, transmission capacity enhancement, and frequency control services. Understanding the baseline from which these innovations emerge is therefore essential to assess both their impact and their scalability.

This section provides a structured analysis of existing business models across four key domains relevant to the selected TwinEU tasks:

- (i) market surveillance and fraud detection (linked to Task 5.4),
- (ii) utilization of distributed resources (Tasks 6.4–6.6 and 7.2),
- (iii) mechanisms for increasing transmission capacity (Tasks 7.3 and 8.4),
- (iv) frequency containment and fast frequency response services (Tasks 7.2, 7.7, and 8.4).

The objective is not merely to describe current practices, but to critically assess their limitations in terms of scalability, interoperability, real-time capability, and alignment with high-renewable, decentralized system operation. Particular attention is given to the extent to which existing models can accommodate cross-layer coordination between TSOs and DSOs, integrate DER-based flexibility, and support emerging services such as fast frequency response.

A key underlying assumption in many current frameworks is that system services are delivered by large, centralized assets and coordinated through relatively slow market and operational processes. This assumption is increasingly invalid. As a result, many existing business models exhibit structural inefficiencies, including limited access for smaller flexibility providers, insufficient real-time observability, and weak integration between market and system operation layers.

Across all analyzed domains, a common pattern emerges: existing business models are predominantly static, centralized, and sequential, while future power systems require dynamic, distributed, and highly coordinated operation. This structural mismatch is the primary source of inefficiencies addressed in the subsequent sections. By establishing this baseline, the section creates a reference point against which the business models and innovations developed within TwinEU can be evaluated in subsequent sections.

3.2.1 Power system operation and planning

Existing business models in power system operation and planning in Europe are largely built around a centralized, hierarchical structure, where Transmission System Operators are responsible for system security and balancing, while Distribution System Operators manage local grid reliability and connections. These roles are complemented by market operators who facilitate energy trading across day-ahead, intraday, and balancing timeframes.

At their core, these models rely on a clear separation between planning, operation, and market activities. Planning processes are typically long-term and deterministic, focusing on network reinforcement, asset investment, and compliance with reliability standards (e.g., N-1 criteria). For example, grid expansion decisions are often based on worst-case load and generation scenarios, leading to infrastructure investments that remain underutilized for most of their lifetime. Operational processes,

on the other hand, are based on real-time monitoring and control of the system, supported by SCADA/EMS platforms and contingency analysis tools. However, these systems are primarily designed for monitoring and control, rather than predictive, data-driven optimization, limiting their ability to anticipate system constraints and proactively activate flexibility. In addition, they often operate with limited visibility of distribution-level conditions, meaning that congestion or voltage issues in lower voltage grids are not fully captured in transmission-level decisions.

Market mechanisms function in parallel, translating system needs into price signals, but are only partially coupled with real-time grid constraints. A clear example is the European day-ahead market, where clearing results are based on zonal pricing and predefined transfer capacities, which do not always reflect real-time grid conditions. This can lead to situations where economically optimal market outcomes require costly redispatch actions by TSOs to maintain system security.

A key characteristic of these business models is that value creation is asset-centric. Revenues and cost recovery mechanisms are primarily linked to capital-intensive infrastructure investments (regulated asset base for TSOs/DSOs) or large-scale generation participation in wholesale markets. From a value flow perspective, this results in a clear separation between regulated and market-based revenues: TSOs and DSOs recover costs through regulated tariffs linked to infrastructure investments, while generators and market participants derive revenues from energy and ancillary service markets. This structure reinforces incentives toward capital expenditure and asset availability, rather than toward dynamic system support or real-time flexibility provision.

Another defining feature is the limited coordination between transmission and distribution levels. While TSOs manage system-wide balancing and frequency control, DSOs have historically operated passively, without active participation in system services or market-based flexibility provision. In practice, this results in situations where distributed flexibility, such as residential demand response or battery storage, is technically available but cannot be activated due to lack of market access or coordination mechanisms between TSOs and DSOs.

From a market perspective, existing frameworks assume relatively predictable system behavior and rely on sequential market clearing processes (day-ahead → intraday → balancing). While efficient under traditional system conditions, this structure struggles to accommodate the variability and uncertainty introduced by high shares of renewable energy sources. For example, forecast errors in wind or solar generation often lead to increased reliance on balancing markets, where activation costs are significantly higher than in earlier market stages.

Several structural limitations emerge from these characteristics:

- **Limited integration of distributed energy resources:** Small-scale assets, such as rooftop PV combined with battery systems, are rarely able to participate directly in wholesale or ancillary service markets without aggregation.
- **Insufficient real-time coordination:** Market outcomes and operational constraints are misaligned, as seen in the need for redispatch actions following day-ahead market clearing.
- **Static capacity assumptions:** Transmission capacities are typically predefined (e.g., NTC or flow-based limits), rather than dynamically updated using real-time data such as weather-dependent line ratings.

- **Reactive rather than preventive operation:** Congestion management is often addressed after it occurs, rather than through predictive or preventive measures based on real-time analytics.

Under high shares of variable renewable generation, these limitations become most visible in the increasing reliance on redispatch, congestion management, and balancing actions, indicating that existing planning and market coordination mechanisms are no longer sufficient to ensure efficient system operation.

These limitations are directly relevant to the focus areas of this analysis. Challenges in integrating DERs underpin the need for new models of distributed resource utilization (Section 2.3.3), while the static treatment of network capacity motivates innovations in transmission capacity enhancement (Section 2.3.4). Similarly, the separation between market operation and system monitoring highlights gaps in market surveillance and fraud detection (Section 2.3.2), and the reliance on conventional generators exposes shortcomings in fast frequency response provision (Section 2.3.5).

Overall, existing business models provide a stable and well-understood foundation for system operation, but they are not designed for a highly digitalized, decentralized, and real-time optimized power system. This creates both constraints and opportunities for the innovations introduced within the TwinEU project.

3.2.2 Market surveillance

Market surveillance and fraud detection in electricity markets have traditionally been designed around regulatory compliance and ex-post analysis, rather than real-time operational monitoring. The primary objective of existing frameworks is to ensure market integrity, prevent manipulation, and maintain fair competition, typically under regulatory regimes such as REMIT (Regulation on Wholesale Energy Market Integrity and Transparency).

Current approaches are largely rule-based and reactive, relying on predefined indicators of suspicious behaviour and retrospective data analysis. Market operators and regulators monitor trading activities using statistical screening methods, such as price-volume anomalies, unusual bidding patterns, or deviations from historical behaviour. For example, sudden spikes in balancing market prices or repeated withdrawal of capacity may trigger investigations into potential market manipulation. However, these analyses are typically conducted after market clearing, limiting their ability to prevent harmful impacts in real time.

A key limitation of existing surveillance models is their restricted visibility across the full value chain. Market monitoring is often performed independently from system operation, meaning that trading behaviour is not always evaluated in the context of real-time grid conditions. For instance, a market participant may submit strategically high bids in a congested area where the TSO has limited alternatives, effectively exploiting local grid constraints.

A practical example of this can be observed in balancing markets, where a generator or aggregator with local market power may withhold available capacity during earlier market stages (e.g., day-ahead or intraday), only to offer it later in the balancing market at significantly higher prices. While this behaviour may remain within formal market rules, it leverages system constraints and limited competition in specific locations, ultimately increasing system balancing costs.

Another structural issue is the increasing complexity and number of market participants, particularly with the emergence of distributed energy resources and local flexibility markets. Traditional surveillance systems were designed for a relatively small number of large, well-characterized actors. In contrast, modern systems must account for aggregators, prosumers, and automated trading agents, significantly increasing the risk surface. A concrete example is the participation of aggregators in balancing markets, where incomplete or inaccurate data reporting can lead to overestimation of available flexibility, potentially compromising system reliability.

Fraud detection mechanisms also face challenges related to data integrity and digital identity management. Existing systems often assume that submitted data (e.g., generation schedules, availability declarations, or metering data) is accurate and trustworthy. However, risks such as false data injection, identity spoofing, or manipulation of flexibility bids are not systematically addressed in current frameworks.

A concrete example is the overstatement of available flexibility by an aggregator participating in a balancing market. If the declared capacity is not fully verifiable in real time, the TSO may rely on resources that are not actually deliverable when activated. This can lead to imbalances, emergency corrective actions, and increased system costs, while remaining difficult to detect under existing validation frameworks.

From a technological perspective, most existing approaches rely on centralized data processing and static thresholds, with limited use of advanced analytics. While some market operators have begun integrating machine learning techniques for anomaly detection, these applications remain relatively isolated and are not tightly coupled with system operation tools. As a result, detection capabilities are often insufficient to identify coordinated or sophisticated manipulation strategies, especially those spanning multiple market layers or timeframes.

An additional limitation of current approaches is the lack of automated and timely response mechanisms. Even when suspicious behaviour or anomalies are identified, mitigation actions—such as bid rejection, redispatch adjustments, or market intervention—are typically manual and subject to regulatory procedures. This delay reduces the effectiveness of detection and allows potentially harmful market outcomes to materialize before corrective actions are taken.

These challenges are further reinforced by misaligned incentives within existing market designs. Market participants are incentivized to maximize individual profit within the rules, which may include exploiting informational asymmetries or system constraints. At the same time, TSOs and regulators are primarily focused on system security and compliance, rather than real-time market optimization. This divergence creates structural conditions where inefficient or borderline manipulative behaviour can persist without clear violations of formal rules. In increasingly coupled markets, such strategies may also span multiple timeframes (e.g., day-ahead, intraday, balancing), making them harder to detect using isolated monitoring approaches.

These limitations become more pronounced in the context of increasing digitalization and market coupling. The lack of real-time, system-aware surveillance mechanisms creates vulnerabilities that can be exploited by market participants, whether intentionally (fraud, manipulation) or unintentionally (erroneous data submission). Furthermore, the absence of automated response mechanisms means that even when anomalies are detected, mitigation actions are often delayed and manually executed.

In summary, existing business models for market surveillance are characterized by:

- **Reactive and ex-post analysis**, rather than real-time detection and prevention
- **Limited integration with system operation**, reducing contextual awareness
- **Inadequate handling of distributed and small-scale participants**
- **Weak data validation and identity verification mechanisms**
- **Limited use of advanced, AI-driven detection tools**
- **Lack of automated response mechanisms**, reducing effectiveness of detection

These shortcomings highlight the need for more integrated, real-time, and data-driven surveillance frameworks. In particular, the increasing importance of local flexibility markets and DER participation introduces new risks that cannot be effectively managed using traditional approaches. This directly motivates the developments explored in Task 5.4, where digital twins and advanced analytics are used to enable proactive detection of abnormal market participation and automated activation of mitigation protocols.

3.2.3 Resources from the distribution network

The utilization of resources from distribution networks, particularly Distributed Energy Resources (DERs), has gained increasing attention as power systems transition toward higher shares of renewable generation and decentralization. Existing business models aim to leverage DER flexibility for system services such as congestion management, balancing, and voltage control. However, despite significant progress in recent years, these models remain fragmented, limited in scale, and often constrained by regulatory and technical barriers.

Traditionally, distribution networks were designed as passive systems, where power flows unidirectionally from transmission to end consumers. As a result, DERs such as rooftop photovoltaic systems, battery storage, electric vehicles, and demand response have not been fully integrated into system operation or market participation. Their utilization has primarily been limited to local optimization or self-consumption, rather than system-wide service provision.

One of the main existing approaches to DER utilization is through aggregation models, where multiple small-scale resources are pooled together to meet minimum market participation thresholds. Aggregators enable DERs to participate in wholesale and balancing markets by combining their capacities into a single, dispatchable portfolio. For example, residential battery systems or industrial demand response units can be aggregated to provide balancing services to TSOs. However, these models often face challenges related to forecasting accuracy, availability verification, and coordination across multiple assets. In addition, the definition of reliable baselines for flexibility provision remains a fundamental issue. For demand response and prosumer-based services, the value of flexibility depends on the deviation from an expected consumption or generation profile, but establishing accurate and manipulation-resistant baselines is inherently difficult, creating uncertainty in both market settlement and verification processes.

Another approach is the development of local flexibility markets (LFMs), where DSOs procure flexibility services to manage congestion or voltage issues within distribution networks. In these markets, DER

owners or aggregators can offer services such as load reduction, generation curtailment, or reactive power support. While LFMs have been successfully demonstrated in several pilot projects, their implementation remains inconsistent across Europe, with limited standardization and unclear long-term revenue mechanisms for participants. In many cases, distribution-level constraints are not explicitly reflected in market prices, leading to inefficient dispatch decisions and the need for corrective actions outside of market mechanisms.

A practical limitation of both aggregation and local market approaches is the lack of effective coordination between TSOs and DSOs. In many cases, the same DER flexibility could theoretically be used for multiple purposes (e.g., local congestion management and system balancing), but existing frameworks do not provide mechanisms for efficient prioritization or co-optimization. This can lead to conflicts or underutilization of available flexibility.

A typical example is a battery connected to a distribution network that is contracted by a DSO for local congestion management during peak hours. At the same time, the TSO may experience a system-wide imbalance and activate more expensive balancing reserves, even though the battery could technically provide this service. Due to the lack of real-time coordination and market integration, the resource remains unavailable for the higher-value system need, resulting in inefficient overall system operation and increased costs. In more complex situations, conflicting signals may arise, where a DER is simultaneously incentivized to increase consumption (e.g., due to low market prices) and reduce load (e.g., due to local congestion). Without coordinated control mechanisms, such conflicting signals can lead to inefficient or even counterproductive system behaviour.

A further challenge arises from the tension between market-based competition and system-wide coordination. While flexibility markets aim to enable competitive participation of DERs, system operation requires coordinated activation of resources across network levels. In practice, purely market-based activation may not lead to system-optimal outcomes, particularly when multiple actors compete for the same flexibility resources without a shared optimization framework.

In addition, access barriers for small-scale participants remain significant. Prequalification requirements, minimum bid sizes, and strict telemetry and control standards often prevent individual DERs from directly participating in system services. Even when aggregation is possible, transaction costs, contractual complexity, and regulatory uncertainty can limit participation, reducing the overall available flexibility in the system.

From a technical perspective, the utilization of DERs is constrained by limited observability and control at the distribution level. Many DSOs lack real-time visibility of low-voltage networks, making it difficult to reliably assess and activate distributed flexibility. This results in conservative operational practices, where DER potential is either underutilized or not considered in system planning and operation.

Another key challenge is the static nature of current capacity allocation mechanisms. Hosting capacity for DERs is often determined using conservative, worst-case assumptions, which can delay or prevent new connections. Similarly, flexibility is typically procured based on predefined needs rather than dynamically optimized using real-time system conditions.

While many of these approaches have been successfully demonstrated in pilot environments, their scalability remains uncertain. Solutions that perform well with a limited number of participants often face

significant challenges when extended to thousands or millions of distributed assets, particularly in terms of communication requirements, computational complexity, and market coordination.

These limitations are increasingly problematic as DER penetration grows. While existing business models provide initial pathways for integrating distributed resources, they are not designed for large-scale, real-time, and coordinated utilization across transmission and distribution systems.

In summary, current approaches to DER utilization are characterized by:

- **Fragmented and pilot-driven implementation**, with limited standardization
- **Dependence on aggregation models**, with associated coordination and forecasting challenges
- **Limited TSO–DSO coordination**, leading to inefficient use of flexibility
- **Conflict between market-based activation and system-wide optimization**
- **High entry barriers for small-scale resources**
- **Challenges in baseline definition and verification of flexibility**
- **Insufficient real-time visibility and control in distribution networks**
- **Limited scalability of current solutions**

These challenges directly motivate the developments explored in Tasks 6.4–6.6 and 7.2, where digital twins, improved data exchange, and coordinated market mechanisms aim to enable scalable, real-time utilization of distributed flexibility across grid levels.

3.2.4 Transmission capacity

Increasing transmission capacity is a central objective in modern power systems, driven by the need to integrate large volumes of renewable energy, facilitate cross-border electricity trade, and maintain system security under changing operating conditions. Existing business models for enhancing transmission capacity are primarily based on a combination of infrastructure expansion, operational optimization, and market-based allocation mechanisms. However, these approaches remain largely static and conservative, limiting their ability to fully utilize available grid capacity.

The most traditional mechanism is grid reinforcement and expansion, involving the construction of new transmission lines, substations, or upgrades to existing infrastructure. These investments are typically justified through long-term planning processes and recovered via regulated tariffs. While effective in increasing physical capacity, this approach is capital-intensive, slow to implement, and often constrained by permitting challenges and public acceptance issues. As a result, infrastructure expansion alone cannot keep pace with the rapid growth of renewable generation and evolving power flow patterns.

In parallel, system operators rely on operational measures to maximize the use of existing infrastructure. One of the most common approaches is the application of conservative, static transmission limits based on worst-case assumptions (e.g., thermal limits under high ambient temperatures and low wind conditions). While this ensures system security, it often leads to significant underutilization of available capacity under typical operating conditions. Importantly, this conservatism reflects a risk-averse

operational paradigm, where the potential consequences of constraint violations outweigh the benefits of increased capacity utilization.

A more advanced approach is the use of Dynamic Line Rating (DLR), where transmission capacity is adjusted in real time based on environmental conditions such as temperature, wind speed, and solar radiation. For example, overhead lines can often carry significantly higher currents during periods of low ambient temperature or high wind, but these additional margins are not captured by static ratings. Although DLR has been demonstrated in several pilot projects, its large-scale deployment remains limited due to challenges related to data availability, standardization, and integration into operational processes.

A practical limitation can be observed in cases where DLR systems are installed but used only as advisory tools rather than as binding operational limits. In such situations, operators may continue to rely on conservative static ratings due to uncertainty in measurements, lack of regulatory acceptance, or absence of clear operational procedures, resulting in limited real-world impact despite available technology.

Market-based mechanisms also play a key role in capacity utilization, particularly through cross-border capacity allocation frameworks. In Europe, this is implemented through methods such as Net Transfer Capacity (NTC) and flow-based market coupling, which aim to optimize the allocation of transmission capacity between bidding zones.

A simplified comparison of these approaches highlights their limitations:

- **NTC (Net Transfer Capacity):** Capacity is predefined between bidding zones based on conservative assumptions. This approach is simple and robust but often significantly underutilizes the physical network.
- **Flow-based market coupling:** Incorporates a more detailed representation of network constraints using Power Transfer Distribution Factors (PTDFs), allowing for better capacity allocation across multiple zones. However, it still relies on pre-calculated capacity domains and limited real-time updates.
- **Dynamic and probabilistic approaches (emerging):** Capacity is calculated using real-time data and probabilistic scenarios (e.g., renewable generation uncertainty, dynamic line ratings). These approaches are not yet widely implemented but offer the potential for significantly higher and more efficient capacity utilization.

A practical consequence of the limitations of current approaches is the frequent need for redispatch and countertrading actions. For example, a transmission corridor may be assigned a day-ahead capacity of 1,000 MW based on conservative assumptions, while real-time conditions would allow safe operation at 1,200 MW. Because this additional capacity is not made available to the market, cheaper generation cannot be dispatched across the constraint. As a result, TSOs may need to curtail low-cost generation in one area and activate more expensive generation elsewhere, leading to redispatch costs that can exceed several hundred €/MWh in congested situations.

Another emerging mechanism is the use of topological optimization and remedial actions, such as switching operations, phase-shifting transformers, or flexible AC transmission system (FACTS) devices. These tools allow operators to influence power flows and relieve congestion without physical expansion.

However, their use is often limited by operational complexity, lack of automation, and insufficient integration with market processes.

A key limitation across all these approaches is the static and fragmented treatment of transmission capacity. Capacity is often determined separately for planning, market clearing, and real-time operation, with limited feedback between these stages. This results in conservative capacity estimates in market processes and reactive adjustments in real-time operation.

From a business model perspective, an additional challenge lies in the distribution of costs, risks, and benefits. Increasing transmission capacity—whether through dynamic methods or improved optimization—can generate significant system-wide benefits, such as reduced redispatch costs and improved market efficiency. However, these benefits are not always directly captured by the actors responsible for implementing the solutions. At the same time, TSOs bear the operational risks associated with capacity overestimation, reinforcing conservative decision-making and limiting the adoption of more dynamic approaches.

In addition, existing models do not fully exploit the potential of data-driven and probabilistic methods. Transmission capacity is typically calculated deterministically, without systematically incorporating uncertainty related to renewable generation, demand variability, or equipment behavior. This leads to either overly conservative limits or increased reliance on corrective actions.

In summary, current mechanisms for increasing transmission capacity are characterized by:

- **Strong reliance on infrastructure expansion**, with long lead times and high costs
- **Conservative, risk-driven capacity limits**, leading to underutilization of existing assets
- **Limited operational use of dynamic approaches such as DLR**
- **Partial integration of physical constraints into market mechanisms**
- **Misalignment between risk, cost, and benefit allocation**
- **Frequent reliance on redispatch**, indicating inefficiencies in capacity allocation

These limitations highlight the need for more dynamic, data-driven, and integrated approaches to transmission capacity management. In particular, the developments in Tasks 7.3 and 8.4 aim to address these challenges through co-optimization of markets, probabilistic capacity calculation, and improved integration of real-time system conditions into market and operational processes.

3.2.5 Frequency containment and fast frequency response

Frequency control is a fundamental component of power system operation, ensuring the continuous balance between generation and demand. Existing business models for frequency control in Europe are primarily structured around a hierarchy of ancillary services, including Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR), and manual Frequency Restoration Reserve (mFRR). These services are procured through market-based mechanisms and are designed to maintain system stability following disturbances.

At the core of current frameworks is FCR, which provides an automatic and proportional response to frequency deviations within seconds (typically stabilizing frequency within ~30 seconds). Traditionally, FCR has been supplied by large synchronous generators, whose physical inertia and governor response inherently support frequency stability. Market designs for FCR reflect this legacy, with standardized products, symmetric bid requirements, and strict prequalification criteria. In contrast, aFRR and mFRR are slower-acting reserves, with activation times ranging from minutes to tens of minutes, designed to restore frequency toward nominal values after initial containment. Fast Frequency Response (FFR), emerging as a complementary service, acts much faster—often within 1–2 seconds—addressing the immediate frequency drop in low-inertia systems.

A key limitation of existing FCR models is their dependence on conventional generation technologies. As synchronous generation is progressively displaced by inverter-based renewable energy sources, the natural inertia of the system is reduced, leading to faster and larger frequency deviations following disturbances. For example, in low-inertia areas of the Nordic grid, RoCoF (Rate of Change of Frequency) can exceed 0.5 Hz/s during large generation outages, compared to 0.1–0.2 Hz/s in high-inertia regions of Continental Europe. However, existing procurement mechanisms have not fully adapted to this shift, and the contribution of inverter-based resources remains constrained by regulatory and technical barriers.

Market and regulatory frameworks are evolving, but adaptation remains uneven across Europe. Some countries have begun integrating DER aggregation into frequency services or running FFR pilot projects, yet harmonized EU-wide mechanisms are still limited. Current reserve procurement is largely static, based on deterministic criteria rather than real-time system conditions, which can lead to over-procurement in some regions and insufficient fast-response capability in others. The ENTSO-E Network Codes on Electricity Balancing provide a framework for harmonization, but national implementations vary, limiting cross-border optimization of fast-response resources.

Another practical limitation of current approaches is the mismatch between system needs and service design. In low-inertia systems, frequency may drop significantly within the first few seconds after a disturbance, before traditional FCR reserves are fully activated. Even sufficient FCR capacity may be unable to prevent frequency from approaching critical thresholds, highlighting the need for faster-acting services such as FFR.

Existing business models also do not fully account for the locational and dynamic aspects of frequency response. While frequency is often treated as a system-wide variable, local network conditions can influence the effectiveness of response actions, particularly in systems with high shares of inverter-based resources and uneven inertia distribution.

In summary, current approaches to frequency containment and fast frequency response are characterized by:

- Strong reliance on traditional FCR products, designed for synchronous generation.
- Limited integration of fast-acting, inverter-based resources, including DERs.
- Lack of dedicated, harmonized FFR market mechanisms across Europe.
- Static procurement approaches, not fully aligned with real-time or regional system needs.
- Barriers to DER participation, reducing available flexibility.

These limitations highlight the need for new service designs and market mechanisms that can accommodate fast, distributed, and inverter-based response capabilities. The developments explored in Tasks 7.2, 7.7, and 8.4 address these challenges by introducing new FFR products, enabling DER participation, and integrating frequency services into coordinated market and operational frameworks.

3.3 Identification of Potential New Services and Business models Enabled by TwinEU

3.3.1 Overview of TwinEU-enabled services

The TwinEU Horizon project develops a coherent portfolio of new business models and digital services aimed at transforming the operation, planning, and market integration of European power systems through the use of Digital Twin (DT) technologies. These services respond to emerging challenges driven by high shares of renewable energy sources, increasing decentralisation of resources, growing cross-border exchanges, and the need for enhanced system flexibility, transparency, and security. Rather than focusing on isolated innovations, TwinEU adopts a cross-pilot and cross-domain approach, where multiple demonstrators validate complementary capabilities across transmission and distribution system operators, market operators, aggregators, and other stakeholders.

At the core of TwinEU's approach is the concept of DT-enabled services that integrate real-time and forecast data, advanced modelling, probabilistic analysis, and simulation tools into operational and market processes. These services are organised into business cases that represent specific value propositions, each addressing a distinct system need while contributing to a broader ecosystem of interoperable solutions. The business models underpinning these services combine operational benefits (e.g., improved reliability, congestion management, and system visibility) with new market opportunities (e.g., flexibility services, ancillary services, and data-driven offerings), enabling both system efficiency and commercial viability.

The identified business cases can be grouped into four main service clusters: (1) market surveillance and integrity, (2) utilisation of distributed resources, (3) transmission capacity enhancement, and (4) fast frequency response services. Each cluster reflects a key functional area of modern power systems and is supported by multiple pilot implementations across Europe, ensuring validation under diverse regulatory and technical conditions.

The first cluster focuses on market surveillance and integrity services, exemplified by the abnormal market participation detection business case. This introduces DT-enabled monitoring and protocol activation capabilities that allow TSOs, DSOs, and market operators to detect anomalies in market behaviour, ensure compliance, and maintain trust in increasingly digitalised and decentralised electricity markets. The corresponding service provides real-time analytics, anomaly detection, and automated response mechanisms, contributing to cybersecurity, fraud prevention, and regulatory compliance.

The second cluster addresses the monitoring, coordination, and activation of distributed energy resources. This includes services that enable DSOs and TSOs to improve observability of distribution networks, coordinate flexibility across system levels, and activate distributed resources such as demand response, storage, electric vehicles, and small-scale generation. These services support the emergence of flexibility markets, enhance congestion management, and facilitate the integration of DERs into system

operation. Business models in this cluster include flexibility aggregation platforms, DER prequalification services, and coordination mechanisms between TSOs and DSOs, supported by federated DT architectures.

The third cluster focuses on increasing transmission capacity, both within individual bidding zones and across borders. Services in this area aim to replace or complement traditional static capacity calculation methods with dynamic, data-driven, and probabilistic approaches. Advanced operational assessment services leverage real-time data, dynamic line ratings, and flow-based market coupling, while probabilistic cross-border capacity calculation services incorporate uncertainty from renewable generation, demand variability, and contingencies. These services enable more accurate ATC estimation, improved congestion management, and more efficient utilisation of interconnection capacity, while also supporting cross-border coordination among TSOs and market operators.

The fourth cluster introduces Fast Frequency Response (FFR) as a new ancillary service. This service addresses the need for rapid frequency stabilisation in systems with high penetration of inverter-based resources. The FFR business case combines technical definition, market integration, and operational validation across multiple pilots. It enables fast-responding resources such as batteries, demand response, and electric vehicles to provide immediate frequency support, bridging the gap between primary frequency control and slower balancing reserves. The service is supported by digital twin-based analysis, probabilistic assessment of system conditions, and co-optimized market mechanisms that allow FFR to be procured, activated, and settled within integrated market frameworks.

Across all clusters, TwinEU emphasises the importance of interoperability, data exchange, and coordination between stakeholders through a federated digital twin architecture. This architecture enables different system layers (transmission and distribution), geographical regions, and operational domains (market, grid, and flexibility) to interact within a unified framework while preserving local autonomy. It also supports scalability and replicability of services across European regions.

In summary, TwinEU's new business models and services represent a transition from traditional, siloed approaches to a more integrated, data-driven, and flexible energy system. By combining advanced digital twin technologies with innovative market designs and cross-stakeholder collaboration, these services enhance system observability, improve operational decision-making, unlock new sources of flexibility, and support the secure and efficient integration of renewable energy across Europe.

3.3.2 Mapping of TwinEU tasks' business cases to service clusters

The mapping of new business cases and services within the TwinEU Horizon project reflects how individual demonstrators and tasks contribute to a coherent set of cross-cutting capabilities across transmission and distribution system operation, market design, and flexibility integration. Each business case is supported by multiple pilots, ensuring that concepts are validated in different regulatory, technical, and market environments while leveraging shared digital twin (DT) principles.

Table 3 consolidates the traceability between the business use cases, contributing TwinEU tasks, pilot contexts, principal service contributions, and the barrier analysis developed in Chapter 3.4.

Table 3: TwinEU task-by-use-case traceability

Use case / service concept	Relevant task(s)	Pilot context	Principal contribution to the service	Chapter traceability	5
Abnormal Market Participation Detection and Protocol Activation	Task 5.4	Iberian pilot	Near-real-time detection of anomalous bids, identity or data irregularities, and activation of proportionate mitigation protocols using market, grid, and cybersecurity data.	Sections 2.5.1.2 and 2.5.2; operational treatment in 2.5.3.4; cross-border surveillance and incident response in 2.5.4.3.	
Distributed Resource Monitoring, Coordination and Flexibility Activation	Tasks 6.4, 6.5, 6.6, and 7.2	German and Greek pilots	Improved distribution-grid observability, DER forecasting and aggregation, flexibility prequalification and activation, and coordinated TSO–DSO use of distributed resources.	Sections 2.5.1.3 and 2.5.2; organisational and operational treatment in 2.5.3.4; cross-border balancing and deliverability in 2.5.4.2.	
Advanced Operational Assessment for Transmission Capacity	Tasks 7.3 and 8.4	Hungarian pilot, complemented by Task 8.4 cross-border developments	Dynamic and flow-based capacity assessment using DLR, co-optimised market timeframes, real-time grid conditions, and predictive congestion analysis.	Sections 2.5.1.4 and 2.5.2; operational integration in 2.5.3.5; regional model, capacity, and remedial-action coordination in 2.5.4.1.	
Probabilistic-based Cross-border Capacity Calculation and Flexibility Assessment	Tasks 8.4 and 7.3	Task 8.4 pilot context, complemented by the Hungarian pilot	Scenario-based ATC and flexibility assessment under VRE, demand, and contingency uncertainty, supported by distribution EDMs, robust optimisation, and market integration.	Sections 2.5.1.4 and 2.5.2; governance and operational treatment in 2.5.3.5; common-model and probabilistic risk coordination in 2.5.4.1.	

New Frequency Response Service	Fast	Tasks 7.2, 7.7, and 8.4	Greek, Slovenian, and Task 8.4 pilot contexts	Market integration and TSO–DSO coordination, technical product definition and activation algorithms, and probabilistic assessment and prequalification of fast-responding resources.	Sections 2.5.1.5 and 2.5.2; qualification, activation, and settlement barriers in 2.5.3.5; synchronous-area and cross-border coordination in 2.5.4.2.
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3.3.3 Identification of key stakeholders

The five business cases described in Section 3.3.2 rely on a common set of stakeholder groups, whose roles differ from one business case to another. Table 4 to Table 8 summarise the role of each stakeholder group in each business case; groups without a direct role are not listed in the corresponding table.

3.3.3.1 Abnormal Market Participation Detection and Protocol Activation

Table 4: Stakeholder roles in the business case “Abnormal Market Participation Detection and Protocol Activation”

Stakeholder group	Role in the business case
TSOs	Integrate DT capabilities into operational processes to monitor market outcomes and assess their impact on system stability; contribute high-level system data; validate abnormal behaviour from a system-wide perspective; coordinate cross-border or system-critical response actions; define and activate mitigation protocols when abnormal participation threatens system reliability.
DSOs	Provide detailed visibility of distribution networks and are often the first to detect local irregularities; operate DT-based surveillance tools to monitor participation in LFMs and identify suspicious or inconsistent behaviour; initiate predefined response protocols; interact with local market participants; may provide new monitoring and cybersecurity-compliance services.
Market operators	Provide essential market data (bids, clearing); align monitoring mechanisms with market rules and procedures; collaborate with TSOs and DSOs to identify abnormal patterns, verify data integrity and enforce market regulations; ensure corrective

Stakeholder group	Role in the business case
	actions comply with regulatory frameworks without unnecessarily disrupting market functioning.
Aggregators and flexibility service providers	Both subjects of monitoring and beneficiaries of increased market transparency and security; ensure compliance with market rules; maintain secure communication and data-exchange systems; respond to requests for validation or corrective action when anomalies are detected.
Technology and DT providers	Develop and implement the DT infrastructure, data analytics tools and cybersecurity solutions; ensure interoperability, real-time data processing and integration of multiple data sources; translate operational requirements into functional DT services and maintain their performance and scalability.
Regulators and policy makers	Define market rules, cybersecurity requirements and data-governance principles; enable data sharing; support the adoption of new monitoring services; ensure that protocol activation is aligned with existing legislation and market design principles.
Research organisations and project partners	Develop detection methodologies and risk-assessment frameworks; validate the proposed solutions and evaluate pilot results; support transferability across European contexts.

3.3.3.2 Distributed Resource Monitoring, Coordination and Flexibility Activation

Table 5: Stakeholder roles in the business case “Distributed Resource Monitoring, Coordination and Flexibility Activation”

Stakeholder group	Role in the business case
DSOs	Primary actors: deploy and operate local DTs providing high-resolution visibility of MV/LV networks; identify local constraints (congestion, voltage); monitor DER behaviour, forecast grid conditions and initiate distribution-level flexibility activation; facilitate LFMs; may provide new

Stakeholder group	Role in the business case
	services for flexibility procurement, congestion management and hosting capacity optimisation.
TSOs	Rely on aggregated and coordinated information from DSOs to understand the system-wide impact of distributed flexibility; gain visibility of distribution-level dynamics through the federated DT; coordinate activation with DSOs to avoid conflicting actions; define coordination frameworks, particularly in cross-border or system-critical situations.
Aggregators and flexibility service providers	Key enablers: aggregate residential loads, EVs, batteries and distributed generation; interface between prosumers and system operators through market-based or contractual arrangements; ensure reliable delivery and respond to activation signals; maintain communication and control systems compatible with DT-based platforms.
Prosumers and DER owners	Households, commercial and industrial users providing flexibility at the grid edge; enable access to their resources and comply with activation signals, directly or via aggregators; ensure availability and reliability of their assets; benefit from new opportunities to monetise them.
Market operators	Operate transparent, efficient and non-discriminatory flexibility trading platforms, particularly LFMs; provide procurement and settlement infrastructure; integrate DT-based insights where applicable; ensure regulatory alignment; support standardisation of products and processes.
Technology and DT providers	Develop and maintain DT infrastructure, data platforms, communication systems and analytics tools; ensure interoperability, integration of heterogeneous data sources and scalability across pilots and regions; enable real-time monitoring, forecasting and decision support.
Regulators and policy makers	Set rules on market design, data access, interoperability and TSO–DSO coordination;

Stakeholder group	Role in the business case
	enable new flexibility markets and ensure fair access for participants; support innovation while maintaining system security and consumer protection.
Research organisations and project partners	Design DT models, coordination mechanisms and evaluation frameworks; validate methodologies and analyse pilot results; ensure solutions are robust, replicable and transferable.

3.3.3.3 Advanced Operational Assessment for Transmission Capacity

Table 6: Stakeholder roles in the business case “Advanced Operational Assessment for Transmission Capacity”

Stakeholder group	Role in the business case
TSOs	Central actors: calculate and allocate transmission capacity and manage cross-border exchanges; operate DT models of the transmission grid integrating real-time and forecast data; evaluate network constraints, run simulations and determine available capacity; coordinate with neighbouring TSOs for harmonised calculations; activate remedial actions when limits are approached or exceeded.
RSCs / RCCs	Support coordinated operation across TSOs; use aggregated data and DT-based insights for regional security analyses and assessment of cross-border constraints; facilitate coordinated capacity calculation and regional risk mitigation.
Adjacent TSOs and cross-border partners	Share data, align methodologies and participate in coordinated capacity calculations so that DT-based assessments reflect the physical reality of interconnected grids.
Market operators	Allocate capacity to market participants using TSO-calculated values for market coupling and clearing; benefit from more accurate, dynamic capacity inputs; ensure market processes can accommodate more frequent capacity updates.

Stakeholder group	Role in the business case
Generation companies and large consumers	Indirect stakeholders: do not operate DT systems but benefit from improved capacity assessment through increased market opportunities, lower congestion-related costs and better predictability.
Technology and DT providers	Develop and maintain DT infrastructure, simulation tools, data-integration platforms and analytics; integrate diverse data sources (e.g. SCADA, weather data, forecasts); ensure interoperability and scalability across regions.
Regulators and policy makers	Define capacity calculation methodologies (e.g. flow-based or ATC), transparency requirements and TSO coordination obligations; enable adoption of dynamic DT-based approaches; oversee compliance, non-discriminatory access to capacity and market integrity.
Research organisations and project partners	Design DT models; analyse pilot implementations; assess scalability and replicability of the solutions.

3.3.3.4 Probabilistic-based Cross-border Capacity Calculation and Flexibility Assessment

Table 7: Stakeholder roles in the business case “Probabilistic-based Cross-border Capacity Calculation and Flexibility Assessment”

Stakeholder group	Role in the business case
TSOs	Central actors: use DT outputs and probabilistic methodologies to compute ATC under uncertainty; integrate distribution-grid information via EDMs; assess contingencies and system adequacy under high shares of inverter-based resources; use results for operational planning, ancillary service procurement and validation of flexibility resources.
DSOs	Provide granular visibility of distribution networks; develop and deploy EDMs representing distributed generation, storage and demand-side flexibility; ensure accurate representation of local constraints; support TSO–DSO coordination and aggregation of flexibility for cross-border capacity support and balancing.

Stakeholder group	Role in the business case
Market operators and power exchanges	Operate market coupling platforms and auction mechanisms; integrate probabilistic and flow-based constraints into day-ahead, intraday and balancing markets; run co-optimised auctions and manage bidding; provide platforms for simulation, testing and deployment of new market mechanisms.
Market participants	Generators, renewable producers, storage operators, aggregators and large consumers submit bids and offers and can offer flexibility; are evaluated and prequalified for ancillary services (e.g. FFR, congestion relief); benefit from better valuation of their flexibility.
Aggregators and flexibility service providers	Pool DERs and make them accessible to system operators and markets; unlock flexibility from smaller assets for balancing and cross-border capacity support; undergo DT-based prequalification assessing responsiveness, reliability and geographic relevance.
Ancillary service providers and system support resource owners	Providers of frequency containment, FFR and voltage support participate in prequalification processes and are assessed on their technical performance and contribution to system stability under uncertainty.
Technology and DT providers	Develop modelling, simulation and optimisation tools (distributed robust optimisation, probabilistic scenario generation, flow-based market coupling simulation); provide APIs and data-exchange interfaces; develop visualisation and result-export functionalities.
Regulators and policy makers	Ensure compliance with regulatory frameworks and policy objectives; evaluate the implications of probabilistic capacity calculation methods; enable regulatory acceptance of new market mechanisms; facilitate cross-border cooperation.
Research organisations and project partners	Develop methodologies and probabilistic models; design scenarios and define use cases; validate outcomes and support pilot execution.

3.3.3.5 New Fast Frequency Response Service

Table 8: Stakeholder roles in the business case “New Fast Frequency Response Service”

Stakeholder group	Role in the business case
TSOs	Primary actors: define FFR technical requirements, procurement rules and activation triggers; integrate FFR into balancing and ancillary service markets; identify contingencies requiring rapid response and activate FFR during frequency excursions; with DSOs and DT tools, assess system needs and validate resource performance.
DSOs	Provide visibility of MV/LV networks and assess local constraints; support DER prequalification for FFR; ensure FFR activation does not violate distribution limits; enable aggregation of DERs (residential loads, EVs, small-scale storage) into market-ready portfolios.
Balancing market operators and power exchanges	Design and operate mechanisms allowing FFR to be traded; implement co-optimised clearing of FFR with energy and reserve products; manage bidding, settlement and transparent price formation; provide simulation and testing platforms integrated with DT environments.
Market participants	Generators, storage operators, demand response providers and aggregators ensure their assets meet FFR requirements (response time, accuracy, sustainment); undergo prequalification, submit bids and deliver FFR upon activation; monetise their flexibility.
Aggregators and flexibility service providers	Aggregate EVs, batteries and controllable loads into virtual portfolios meeting FFR requirements; manage portfolio-level control and prequalification compliance; interface with market operators and TSOs.
Industrial consumers and demand response participants	Provide FFR through rapid load adjustments; adapt processes for automated or semi-automated response; participate in prequalification and contracts with aggregators or TSOs.

Stakeholder group	Role in the business case
EV ecosystem stakeholders	Charging infrastructure operators and fleet managers provide rapid response through smart charging and V2G; enable communication interfaces and charging flexibility; participate via aggregators or directly where applicable.
Technology and DT providers	Develop activation algorithms, real-time simulation environments, probabilistic system models and TSO–DSO data-exchange platforms; integrate FFR into DT frameworks and provide scenario analysis and validation environments.
Regulators and policy makers	Define market rules and approve FFR products; ensure compliance with European network codes; facilitate cross-border harmonisation of procurement and activation; assess impacts on competition, security of supply and adequacy.
Research organisations and project partners	Contribute to conceptual design and methodology; define technical requirements and KPIs; evaluate impacts on system stability and analyse use cases.

Across all business cases, TSOs and DSOs carry the central operational responsibilities, while market operators, aggregators and resource owners determine the practical uptake of the services. Their effectiveness depends on strong coordination and data exchange between stakeholders, for which the federated Digital Twin architecture of TwinEU provides the common foundation.

3.3.4 Business model analysis

3.3.4.1 Service Cluster 1: Market Surveillance & Abnormal Market Participation Detection and Protocol Activation business case

This business case addresses the growing need for enhanced security, transparency, and resilience of electricity markets in an increasingly digitalised and decentralised energy system. With the rapid expansion of renewable energy sources and the rising number of market participants—particularly in local flexibility markets (LFMs)—the risk of abnormal or malicious market behaviour is becoming more pronounced. These risks include digital identity fraud, submission of false or manipulated data, and other forms of cyber-enabled interference that may compromise both market integrity and system operation.

Within the TwinEU framework, this business case leverages Digital Twin (DT) technology to establish an advanced market surveillance and response capability. A “new service” in this context is the implementation of a DT-enabled monitoring and protocol activation system that allows transmission and distribution system operators to detect, analyse, and respond to abnormal market participation in near

real-time. The service is built upon the integration of operational, market, and cybersecurity-related data, enabling a dynamic comparison between expected and observed behaviours across different market processes.

The core of the business case lies in the formalisation of abnormal market participation and the development of structured response protocols. Through the work carried out in Task 5.4, a comprehensive methodology has been established, covering the full process from conceptual definition to use case development and protocol design. Particular attention has been given to LFMs, where decentralised participation and digital interfaces introduce additional vulnerabilities. By identifying critical points in the LFM value chain, the service enables targeted monitoring and the activation of predefined mitigation actions when anomalies are detected.

From an operational perspective, the DT-based service enhances situational awareness for both TSOs and DSOs. It enables early detection of irregular patterns, such as inconsistencies in bids, unexpected behaviour of market participants, or discrepancies between declared and actual system impacts. Once such anomalies are identified, the system can trigger predefined protocols, which may include validation procedures, temporary restriction of market access, or escalation to relevant authorities. This proactive approach reduces response times and limits the potential impact of cyber incidents or market distortions.

In addition to internal operational improvements, this business case also opens opportunities for new market-oriented services. For example, DSOs could offer real-time monitoring and cybersecurity compliance services to flexibility providers and aggregators participating in LFMs. Such services would increase trust among market participants, facilitate compliance with regulatory requirements, and support the safe scaling of flexibility markets.

A key feature of this business case is its alignment with the federated architecture of TwinEU. The surveillance service can be extended beyond local implementations through the integration of multiple digital twins, enabling cross-border visibility and coordination. This is particularly relevant in interconnected systems, where abnormal behaviour in one area may have wider system implications.

Overall, this business case demonstrates how digital twins can move beyond traditional grid operation use cases and play a relevant role in safeguarding market functioning. By combining advanced data analytics, cybersecurity awareness, and coordinated response mechanisms, the proposed service contributes to a more secure, resilient, and trustworthy energy system, while supporting the continued integration of renewable energy and the development of innovative market structures.

3.3.4.2 Service Cluster 2: Utilization of Resources from Distribution Networks

The relevant tasks for this service cluster are Tasks 6.4, 6.5, 6.6, 7.2.

3.3.4.2.1 Distributed Resource Monitoring, Coordination and Flexibility Activation

This business case addresses one of the most critical challenges of modern power systems: the effective integration and utilisation of distributed energy resources (DERs) in increasingly complex and decentralised electricity networks. With the rapid growth of renewable generation, electric vehicles, heat pumps, and storage systems connected at distribution level, system operators face limited visibility and controllability over large portions of the grid. This creates operational challenges related to congestion management, voltage control, balancing, and overall system reliability.

Within the TwinEU framework, this business case introduces a new service based on Digital Twin (DT) technology that enables enhanced monitoring, coordination, and activation of distributed flexibility across transmission and distribution networks. The service combines real-time data acquisition, advanced modelling, and predictive analytics to provide a dynamic and holistic representation of the grid, including DER behaviour and network conditions.

At its core, the service improves observability of distribution networks, which have traditionally lacked detailed monitoring compared to transmission systems. By integrating data from smart meters, sensors, SCADA systems, and external sources, local digital twins are developed for distribution grids. These are then federated within the TwinEU architecture, enabling coordination with transmission-level digital twins and providing a system-wide perspective. This enhanced visibility allows DSOs and TSOs to better understand current and forecasted grid conditions, including potential bottlenecks and flexibility needs.

The relevance and applicability of this concept are clearly demonstrated in the German pilot (Tasks 6.4, 6.5 and 6.6), where the focus is on increasing distribution grid observability and enabling coordinated use of distributed flexibility. In this pilot, digital twins are used to integrate high-resolution data from distribution networks and DERs, supporting advanced monitoring and forecasting capabilities. This allows DSOs to identify local constraints more accurately and enables more efficient activation of flexibility, particularly in areas with high penetration of renewable energy sources.

A key component of this business case is the coordination between TSOs and DSOs, which is further exemplified in the Greek pilot (Task 7.2). This pilot emphasises the need for vertical coordination mechanisms between transmission and distribution levels, especially in systems with growing distributed generation and limited grid capacity. Through the use of federated digital twins, the Greek pilot demonstrates how shared situational awareness and harmonised data exchange can support coordinated decision-making, ensuring that flexibility activation at the distribution level aligns with transmission system requirements.

Building on this foundation, the service enables the activation of flexibility from distributed resources. This includes demand response, distributed generation curtailment, and storage utilisation. Flexibility can be activated either through market-based mechanisms, such as local flexibility markets, or through direct operational control where applicable. The DT framework supports the identification of optimal flexibility actions based on real-time system needs, forecasted conditions, and network constraints, ensuring that activation is both technically feasible and economically efficient.

From a business perspective, this case creates opportunities for new services targeting both internal operations and external stakeholders. Internally, DSOs and TSOs benefit from improved planning and operational efficiency, reduced need for grid reinforcements, and enhanced reliability. Externally, the service supports the development of flexibility markets and enables new roles for aggregators and prosumers, who can offer their flexibility in a structured and transparent way. It also opens possibilities for DSOs to provide flexibility-related services, such as congestion management or hosting capacity optimisation.

The integration of tasks 6.4, 6.5, 6.6, and 7.2 within this business case reflects a comprehensive approach, covering data acquisition, modelling, coordination mechanisms, and market integration. Demonstrations within TwinEU pilots - particularly in Germany and Greece - validate how DT technologies

can support both real-time operation and long-term planning, ensuring scalability and replicability across different European contexts.

Overall, this business case demonstrates how Digital Twins can transform the management of distributed resources from a passive to an active paradigm. By enabling coordinated monitoring and activation of flexibility, it supports higher penetration of renewable energy, improves system resilience, and contributes to a more efficient and sustainable energy system.

3.3.4.3 Service Cluster 3: Increasing Transmission Capacity (Internal and Cross-border)

The relevant tasks for this service cluster are Tasks 8.4, 7.3.

3.3.4.3.1 Advanced Operational Assessment for Transmission Capacity

This business case addresses the need for more dynamic, accurate, and coordinated assessment of transmission system capacity in the context of increasing system complexity, cross-border exchanges, and high penetration of renewable energy sources. Traditional approaches to transmission capacity assessment are often based on conservative, static assumptions, which can lead to underutilisation of existing infrastructure and limited ability to accommodate variable generation and evolving market conditions.

Within the TwinEU framework, this business case introduces a new service based on Digital Twin (DT) technology that enables enhanced operational assessment of transmission capacity through real-time data integration, advanced simulations, and predictive analytics. The service allows Transmission System Operators (TSOs) to move from static, rule-based capacity calculations toward dynamic, system-aware assessments that reflect actual grid conditions, including topology, weather influences, and real-time loading.

The DT-based service creates a virtual, continuously updated representation of the transmission network, integrating SCADA data, state estimation outputs, weather forecasts, and cross-border exchange information. This enables TSOs to simulate different operational scenarios, assess system constraints, and calculate available transmission capacity or flow-based capacity in a more precise and timely manner. As a result, transmission capacity can be utilised more efficiently without compromising system security.

The applicability and benefits of this approach are demonstrated in the Hungarian pilot (Task 7.3), where the focus is on improving the operational assessment of transmission capacity through enhanced modelling and real-time system representation. In this pilot, digital twins support the evaluation of grid constraints under varying operating conditions, enabling more accurate identification of available capacity margins and potential bottlenecks. This contributes to improved decision-making in both operational planning and real-time system management.

Complementary to this, the Iberian pilot (Task 8.4) extends the concept to a broader, cross-border context, highlighting the importance of coordinated capacity assessment in interconnected systems. Here, the DT framework supports the integration of data from multiple TSOs, enabling a harmonised and more transparent approach to capacity calculation. This is particularly relevant for regions with high cross-border exchanges and increasing variability due to renewable generation. The pilot demonstrates how federated digital twins can enhance coordination, reduce uncertainty, and support more efficient use of interconnection capacity.

A key feature of this business case is the ability to perform predictive and what-if analyses, allowing TSOs to anticipate system conditions and adjust capacity assessments accordingly. For example, the impact of forecasted renewable generation, demand fluctuations, or network outages can be evaluated in advance, enabling proactive congestion management and improved market integration.

From a business perspective, this service delivers significant value both internally and externally. Internally, TSOs benefit from improved operational efficiency, better utilisation of existing infrastructure, and enhanced situational awareness. Externally, more accurate and dynamic transmission capacity assessments enable increased cross-border trade, improved market liquidity, and better integration of renewable energy sources. This supports the development of a more efficient and interconnected European electricity market.

Furthermore, the service contributes to reducing the need for costly grid reinforcements by maximising the use of existing assets. It also supports compliance with evolving regulatory requirements related to capacity calculation methodologies and transparency.

Overall, this business case demonstrates how Digital Twin technology can transform transmission system operation by enabling data-driven, dynamic capacity assessment. By improving accuracy, coordination, and adaptability, the proposed service enhances system reliability, market efficiency, and the integration of renewable energy, contributing to the broader objectives of the European energy transition.

3.3.4.3.2 Probabilistic-based Cross-border Capacity Calculation and Flexibility Assessment

The business case “Probabilistic-based Cross-border Capacity Calculation and Flexibility Assessment” addresses the increasing need for more accurate, data-driven, and uncertainty-aware methods to determine cross-border transmission capacities and assess system flexibility in power systems with high shares of variable renewable energy sources (VRE), inverter-based resources, and distributed energy resources. Within the TwinEU Horizon project, this business case builds upon the integration of digital twin capabilities across transmission and distribution system levels, combining probabilistic modelling, dynamic grid constraints, and advanced market mechanisms to improve both operational planning and market efficiency.

A key objective of this business case is to move beyond deterministic capacity calculation approaches and instead implement probabilistic and scenario-based methodologies that reflect the variability of renewable generation, demand patterns, and network contingencies. In this context, Available Transfer Capacity is evaluated under multiple system states derived from probabilistic scenarios, enabling a more realistic and robust assessment of cross-border exchange capabilities. These calculations are enhanced by incorporating dynamic network characteristics, such as DLR, and by considering the operational flexibility provided by distributed and aggregated resources.

The Hungarian pilot (Task 7.3) contributes to this business case by demonstrating how probabilistic and flow-based considerations can be integrated into co-optimized market coupling mechanisms. In this pilot, day-ahead, intraday, and balancing markets are jointly optimized while accounting for flow-based constraints and dynamic network conditions. The integration of DLR into flow-based domains allows the system to reflect real-time or near real-time transmission capacities, which directly influences cross-border capacity allocation. Through the development of scenario matrices, alignment of DLR input

formats, and operationalization of the HUPX Labs platform, the pilot establishes a simulation environment where market outcomes can be evaluated under varying grid conditions and congestion scenarios. The co-optimization of energy and balancing markets, combined with flow-based domain representation, enables improved congestion management and supports more efficient cross-border exchanges. The ongoing implementation of advanced algorithms and API-based interfaces further facilitates the linkage between market platforms and grid models, providing a foundation for probabilistic capacity assessment embedded within market operations.

Complementing this, the Greek pilot (Task 8.4) focuses on the development of a distributed, data-driven probabilistic framework for cross-border capacity calculation and flexibility assessment using digital twin technologies. A key component is the Equivalent Dynamic Model (EDM) of the distribution grid, which interfaces with the transmission system digital twin and provides detailed representations of distributed resources, including inverter-based generators and flexibility assets. The EDM enables the generation of probabilistic scenarios that capture uncertainties in VRE generation, demand fluctuations, and grid contingencies, which are then used to compute ATC values under different operating conditions. This approach supports robust optimization techniques for capacity allocation and enhances the reliability of cross-border exchanges.

In addition, Task 8.4 addresses the cross-border assessment of flexibility and pre-qualification of resources by identifying the characteristics, location, and volume of flexibility services that can be provided by new market participants. It also investigates the role of grid-forming converters and other advanced technologies in maintaining system stability under high penetration of power electronics. The digital twin framework supports the evaluation of ancillary services such as fast frequency response, enabling system operators to better understand the contribution of distributed assets to system adequacy and resilience. The integration of TSO–DSO data exchange mechanisms further strengthens coordination between system operators, allowing for more accurate representation of distribution-level constraints in transmission-level decision-making.

Overall, this business case enables a paradigm shift from static and deterministic cross-border capacity calculations toward a dynamic, probabilistic, and digitally integrated approach. By combining market simulation (Hungarian pilot) with advanced modelling and digital twin-driven probabilistic assessment (Greek pilot), it supports improved congestion management, more efficient utilization of network assets, enhanced integration of renewables, and better participation of distributed flexibility resources in both energy and ancillary service markets.

3.3.4.4 Service Cluster 4: Fast Frequency Response (FFR) service

The relevant tasks for this service cluster are Tasks 7.7, 8.4, 7.2.

The “New Fast Frequency Response (FFR) Service” business case addresses the growing need for rapid and reliable frequency stabilization in power systems increasingly dominated by variable renewable energy (VRE) sources and inverter-based generation. Within the TwinEU Horizon project, this business case focuses on developing, validating, and operationalizing FFR as a new ancillary service product across European transmission and distribution systems, leveraging digital twin (DT) technologies, coordinated TSO–DSO mechanisms, and probabilistic system analysis to enable fast, market-integrated, and scalable frequency support.

The core objective of this business case is to create a commercially viable, technically robust, and system-compatible FFR service that allows system operators to respond rapidly to frequency deviations, thereby maintaining system stability in high renewable scenarios. The service is designed to activate within seconds, bridging the gap between traditional primary control and slower balancing reserves. It targets multiple sources of flexibility, including grid-connected storage, industrial and residential demand response, adaptive loads, electric vehicles, and generation units capable of rapid output adjustment. By prequalifying these resources and integrating them into market mechanisms, FFR provides both technical system support and economic opportunities for new market participants.

The Greek pilot (Tasks 7.2) focuses on co-optimizing balancing energy and reserve markets under coordinated TSO–DSO schemes. This pilot establishes the framework for integrating FFR into market operations, using realistic day-ahead and balancing market simulation tools, aligned with unified asset registries and transmission–distribution grid models. Through these simulations, the pilot evaluates the feasibility of leveraging distributed energy resources, industrial demand response, and battery storage for FFR provision while considering grid constraints and congestion at both the transmission and medium-voltage distribution levels. The pilot also enables structured prequalification of DERs, ensuring that resources meet technical and operational criteria for participation in ancillary markets. This integration demonstrates how FFR can be offered as a market service while improving congestion management, enhancing TSO–DSO coordination, and supporting DER integration in line with 2030 NECP projections.

The Slovenian pilot (Task 7.7) builds upon this by defining the technical and operational specifications for FFR as a new balancing product at a Continental Europe scale. Using the T6.7 infrastructure and DigSILENT PowerFactory, the pilot develops activation algorithms, tests performance, and validates service characteristics. Key achievements include identifying suitable devices and locations for FFR provision, assessing stakeholder preparedness, and establishing preliminary operational criteria for TSOs, balancing providers, and market operators. The pilot demonstrates the activation of FFR in response to contingencies, enabling storage units, flexible loads, and other fast-responding resources to participate in frequency regulation and balancing markets. Business models are explored for the monetization of FFR, including TSO procurement contracts and market participation of distributed resources, creating new revenue streams while supporting system stability.

Task 8.4 complements these pilots by leveraging probabilistic-based digital twin models for cross-border capacity calculations and flexibility assessment. The Equivalent Dynamic Model (EDM) of the distribution grid, integrated with transmission-level digital twins, provides detailed representations of inverter-based resources and flexible loads. Through scenario-based robust optimization, the framework identifies the type, volume, and locational requirements of FFR-capable resources, ensuring that frequency support services are reliable, scalable, and deployable under varying operating conditions. Probabilistic assessment also supports operational decision-making by providing actionable insights for ancillary service activation and prequalification of fast frequency resources, particularly under high shares of VRE generation and uncertain contingencies.

Together, these pilots and modeling approaches establish the foundation for a holistic FFR business case that spans technical feasibility, market integration, and operational readiness. The service enables TSOs to rapidly stabilize frequency deviations, enhances system resilience in renewable-rich grids, and creates opportunities for new market participants to provide flexible and responsive services. By integrating DERs, storage, and adaptive loads into a structured, market-ready FFR framework, this

business case supports the development of a faster, more efficient, and commercially viable ancillary service ecosystem across Europe. Remaining activities focus on finalizing activation algorithms, validating real-time performance, scaling the service across multiple ENTSO-E bidding zones, and ensuring systematic utilization of DT-derived frequency indicators for operational and market decision-making.

This approach ultimately transforms FFR from a technical contingency measure into a structured, market-integrated service, facilitating secure, flexible, and economically efficient operation of power systems under high renewable penetration.

3.4 Identification of Gaps and Barriers

3.4.1 Regulatory and market-related barriers

The use cases presented in Chapters 3.2 and 3.3 depend not only on technical maturity, but also on whether regulatory and market arrangements permit data-driven services to influence operational decisions, market access, procurement, settlement, and cost recovery. Across the four service clusters, the principal barrier is a mismatch between fast, federated and probabilistic Digital Twin capabilities and frameworks that remain nationally differentiated, product-specific and largely deterministic. The 2024 reform of the European Union electricity market design strengthens the role of flexibility and requires more systematic assessment of flexibility needs, but implementation is still evolving and national arrangements remain uneven. Consequently, TwinEU pilots may demonstrate technical value without yet having a stable route to routine procurement, regulated remuneration, or cross-border replication.

3.4.1.1 Cross-cutting regulatory and market barriers

A first cross-cutting issue is regulatory recognition of Digital Twin outputs. Existing network and market rules generally assign responsibility to licensed operators and rely on approved methodologies, validated measurements, and auditable procedures. A probabilistic forecast, anomaly score, dynamic rating, or federated model output therefore cannot automatically become a binding market or operational input merely because it performs well in a pilot. Regulators and operators need agreed validation standards, performance thresholds, fallback procedures, audit trails, and clear accountability when automated recommendations are wrong or unavailable. In the absence of such arrangements, operators are likely to retain conservative limits and human approval, reducing the real-time value proposition described in Chapter 3.3.

A second barrier concerns fragmented implementation. Although EU network codes and market guidelines establish common principles, detailed rules for aggregation, balancing products, local flexibility procurement, capacity calculation, data access, and cost recovery differ among Member States and bidding zones. This creates uncertainty for technology providers and flexibility service providers that seek to scale a common TwinEU service. Interfaces, qualification procedures, contracts, liabilities, and settlement logic may have to be redesigned for each jurisdiction. Persistent delays in implementing common market methodologies also weaken the timely sharing of flexibility across borders and across market timeframes.

Third, regulated incentives do not consistently reward digitalisation and flexibility as alternatives to conventional reinforcement. TSO and DSO remuneration remains strongly linked to asset investment, while the benefits of better observability, coordinated activation, reduced redispatch, or higher utilisation

of existing lines accrue across several actors and time horizons. Where operators carry operational and cybersecurity risks but cannot retain a proportionate share of the benefits, conservative decisions remain rational. Clear treatment of Digital Twin platforms, sensors, forecasting services, flexibility procurement, and innovation costs within regulated expenditure is therefore necessary. Without it, pilots can remain dependent on research funding rather than becoming durable services.

Fourth, data governance and market governance are inseparable. The proposed services require timely access to operational, metering, weather, asset, bid, and behavioural data from multiple entities. Yet rights to access, process, combine, retain, and disclose these data may be unclear, particularly where commercially sensitive information, critical infrastructure data, or personal data are involved. Market participants may also be reluctant to share information that reveals portfolio strategies or operational constraints. Federated architectures reduce the need to centralise all data, but they do not resolve questions of legal basis, purpose limitation, data quality responsibility, confidentiality, intellectual property, cybersecurity obligations, and liability for erroneous inputs.

3.4.1.2 Barriers to market surveillance and protocol activation

For the “Abnormal Market Participation Detection and Protocol Activation” business case, the central regulatory challenge is translating an analytical warning into a lawful and proportionate intervention. REMIT and its 2024 revision strengthen oversight of increasingly automated wholesale markets, including algorithmic trading, but anomaly detection is not equivalent to proof of manipulation. Digital Twin outputs may indicate inconsistent bids, false availability, identity anomalies, or strategic behaviour linked to network constraints; however, false positives could unjustifiably restrict market access or disclose commercially sensitive information. Any automated or semi-automated protocol therefore requires transparent criteria, human oversight, documentation, rights of review, and a clear division of responsibility among market operators, TSOs, DSOs, national regulators, and ACER.

The use case also sits across regulatory boundaries. REMIT primarily addresses wholesale market integrity, whereas local flexibility markets may involve distribution-level products, smaller participants, consumer assets, and platform-specific rules that are not supervised in the same manner. A behaviour may be economically harmful or operationally risky without meeting the legal threshold for market abuse. Conversely, information needed for system-aware surveillance may be held by a DSO or aggregator but unavailable to the competent authority at the required speed. Replication will therefore require harmonised definitions of abnormal participation, minimum monitoring obligations for local platforms, secure evidence-preservation procedures, and escalation paths that connect local incidents with national and Union-level supervision.

Business-model barriers are equally important. Surveillance is a public-interest function, so charging monitored participants directly may undermine trust or create conflicts of interest. At the same time, regulators may not permit TSOs or DSOs to commercialise compliance services outside their regulated duties. Sustainable deployment may therefore require regulated cost recovery, shared funding among competent authorities and market operators, or competitively procured technology services with strict independence and confidentiality safeguards. A common European approach to certification and interoperability would reduce duplication while preserving national enforcement powers.

3.4.1.3 Barriers to distributed flexibility and TSO–DSO coordination

For distributed resource monitoring, coordination, and flexibility activation, market access remains fragmented. Minimum bid sizes, symmetric product requirements, telemetry obligations, prequalification tests, and collateral or registration requirements can be disproportionate for small DERs. Aggregation mitigates these barriers but introduces further questions concerning the aggregator's legal status, relationships with suppliers and balance responsible parties, compensation for imbalances, portfolio baselines, and responsibility for non-delivery. Different national solutions increase transaction costs and limit the portability of TwinEU aggregation and prequalification services.

Product design can also exclude technically capable resources. Existing reserve and congestion-management products may require durations, symmetry, availability windows, measurement granularity, or activation speeds designed around conventional generators rather than batteries, electric vehicles, controllable loads, or mixed portfolios. Standardisation is needed, but excessive uniformity can overlook local network constraints and resource characteristics. A proportionate framework should permit aggregation and technology-neutral participation while ensuring that services remain physically deliverable at the relevant location and time.

Baseline definition and verification remain particularly difficult for demand response and prosumer flexibility. Settlement requires a credible counterfactual against which delivered flexibility is measured, yet baselines may be uncertain, strategically influenced, or inconsistent across platforms. Digital Twin estimates can improve accuracy, but their regulatory acceptance requires transparent methodology, independent validation, dispute rules, and treatment of model error. Similar issues arise for availability declarations and portfolio substitution. If verification remains expensive or exposes aggregators to unbounded imbalance risk, participation and liquidity will stay limited.

A further barrier is the absence of mature rules for prioritising and co-optimising the same resource across local congestion management, wholesale trading, balancing, and FFR. A DSO may need to preserve flexibility for a local constraint while a TSO values it for system balancing. Without agreed priority rules, reservation mechanisms, common asset registries, and compensation for foregone opportunities, overlapping commitments can produce double counting or contradictory activation signals. DSOs' role in procuring or facilitating flexibility must also be separated from competitive activities to preserve neutrality and non-discriminatory access.

3.4.1.4 Barriers to dynamic and probabilistic transmission capacity services

For advanced operational assessment and probabilistic cross-border capacity calculation, the principal obstacle is the approval of methodologies that deliberately depart from conservative deterministic practice. Dynamic Line Rating, scenario-based ATC, and probabilistic flow-based domains can release additional capacity, but the TSO remains accountable for security if a forecast, sensor, or model overestimates the safe margin. Regulatory methodologies must therefore specify acceptable confidence levels, validation and redundancy requirements, forecast horizons, treatment of missing data, and fallback to static ratings. Unless the additional operational risk is recognised and governed, pilot outputs may remain advisory rather than becoming binding market inputs.

Timing is another market barrier. Day-ahead, intraday, and balancing processes have fixed gate closures and common calculation cycles. More frequent capacity updates can improve efficiency, but they

can also reduce predictability for market participants, create redispatch exposure, or conflict with established capacity-calculation and congestion-management procedures. The value of dynamic capacity will therefore depend on harmonised rules on when updated limits enter the market, how changes are communicated, how firmness is protected, and who bears the cost when capacity is reduced after allocation.

The distribution of costs and benefits is also problematic. A TSO may fund sensors, weather services, models, and operational integration, while benefits appear as lower redispatch costs, greater cross-border welfare, reduced curtailment, or improved market liquidity across several countries. National incentive regulation may not reward these regional benefits, and neighbouring operators may apply different risk tolerances. Replication thus requires coordinated regulatory approval, benefit-sharing principles, and incentives linked to efficient capacity utilisation rather than only physical expansion. For the probabilistic service, regulators must additionally determine how model uncertainty is disclosed without overwhelming market participants or revealing security-sensitive information.

3.4.1.5 Barriers to a market-ready Fast Frequency Response service

The FFR use case faces a more fundamental product-definition barrier. European balancing frameworks are increasingly harmonised, but FFR is not yet a single, standardised product across synchronous areas and national markets. Requirements for activation speed, measurement, directionality, sustainment, recovery, availability, and locational relevance differ according to system conditions. If requirements are too technology-specific or mirror legacy FCR arrangements, inverter-based and distributed resources may be excluded; if they are too permissive, the procured response may not arrest frequency quickly enough.

Market design must also determine whether FFR is procured separately, combined with FCR, or co-optimised with energy and other reserves. Separate procurement can reveal scarcity and support investment, but may fragment liquidity; bundling can lower transaction costs but may conceal the value of very fast response. Static procurement volumes may over-procure during high-inertia periods and under-procure when inverter-based generation dominates. The TwinEU proposal for probabilistic assessment therefore needs a regulatory route through which changing system needs can influence procurement volumes, while preserving transparency and predictability for providers.

Prequalification and settlement are further constraints. Thousands of devices cannot be tested and monitored using procedures developed for individual power plants. Portfolio-based qualification, controlled substitution of assets, and statistically robust performance assessment are needed, together with clear metering requirements and rules for rebound or recovery effects. Participation from distribution-connected resources also requires confirmation that rapid activation will not violate local voltage, thermal, or protection limits. This makes real-time TSO–DSO coordination a market-enabling requirement rather than merely a technical enhancement.

3.4.1.6 Implications for deployment and replication

Across the use cases, four enabling conditions are common. First, Digital Twin outputs need approved assurance frameworks covering validation, auditability, cybersecurity, fallback operation, and liability. Second, market rules should be technology-neutral and proportionate, with aggregation, portfolio qualification, and access for smaller resources. Third, incentive regulation must permit recovery of

efficient digital and flexibility-related expenditure and recognise system-wide benefits. Fourth, governance arrangements must define trusted data exchange and decision rights among TSOs, DSOs, market operators, regulators, aggregators, and technology providers.

Regulatory sandboxes and staged deployment can help bridge the gap between demonstration and routine operation, provided that pilots test not only algorithms but also contracts, governance, settlement, consumer safeguards, and accountability. Common European templates for data-sharing agreements, prequalification evidence, model assurance, procurement, and performance reporting would reduce replication costs. Nevertheless, harmonisation should preserve justified regional differences, particularly for frequency dynamics, network topology, and local flexibility needs.

In conclusion, the principal gap is not the absence of European policy direction, but the incomplete translation of that direction into operational methodologies, national incentives, and investable market arrangements. The TwinEU use cases will become scalable services only when technical capability is matched by regulatory legitimacy, predictable remuneration, enforceable coordination, and fair allocation of risk. Addressing these barriers is therefore a prerequisite for the recommendations in Chapter 3.5 and for replication beyond the pilot environments.

3.4.2 Technical and data-related gaps

The TwinEU use cases described in Chapter 4 require Digital Twins that are sufficiently accurate, timely, interoperable, secure, and computationally scalable to support operational and market decisions. Current pilot environments demonstrate important components of this capability, but several gaps remain between proof-of-concept implementation and continuous deployment in production systems. These gaps are closely interdependent: weak source data reduces model accuracy; inconsistent semantics obstruct federation; limited communication and computing performance prevents real-time use; and insufficient validation limits operator confidence in automated recommendations. The consequence is that technically promising services may remain advisory, local, or manually supervised rather than becoming trusted operational capabilities.

A primary cross-cutting gap concerns data availability and quality. The proposed services combine SCADA and EMS measurements, smart-meter data, asset registers, GIS and network models, weather observations and forecasts, market bids, schedules, metering data, and DER telemetry. These sources differ in resolution, refresh rate, accuracy, completeness, ownership, and time synchronisation. Distribution networks are particularly affected by incomplete observability, outdated topology records, unbalanced phase representation, and sparse measurements at low-voltage level. Missing values, duplicated identifiers, inconsistent units, delayed telemetry, and undetected changes in equipment status can propagate through a federated model and produce apparently credible but incorrect outputs.

The absence of common, operationally enforced data-quality indicators is therefore a significant limitation. Completeness, accuracy, timeliness, provenance, and confidence should accompany critical data exchanges, yet current interfaces often provide values without sufficient metadata to determine whether they remain fit for a particular use. A forecast suitable for day-ahead planning may be unsuitable for FFR activation, while an aggregated DER estimate may support market simulation but not local congestion management. TwinEU services require use-case-specific quality thresholds, automated

validation, traceable correction procedures, and graceful degradation when inputs fall below the required standard.

Interoperability is a second major gap. TSOs, DSOs, market operators, aggregators, and technology providers use heterogeneous data models and proprietary interfaces developed for different purposes. Existing standards such as CIM, CGMES, IEC 61850, and market-message profiles provide important foundations, but implementation profiles, extensions, identifiers, versioning practices, and validation rules are not always aligned across transmission, distribution, and market domains. CGMES is well established for exchanges of transmission grid models, whereas detailed representation of distributed flexibility, inverter controls, local market products, probabilistic scenarios, and Digital Twin state remains less harmonised. Mapping between standards frequently depends on customised middleware, increasing integration cost and the risk of semantic loss.

Federation introduces additional technical complexity. Local Digital Twins must retain autonomy while exchanging selected states, models, forecasts, and service requests. This requires persistent cross-domain identifiers, machine-readable metadata, discovery mechanisms, access-control policies, version compatibility, and clear handling of conflicting or asynchronously updated information. Without these capabilities, two models may refer to the same physical resource differently, use different temporal conventions, or apply incompatible assumptions. The resulting inconsistency is particularly problematic when one service chains outputs from several twins, for example when a distribution EDM feeds a transmission capacity calculation or when DER availability informs co-optimised FFR procurement.

Model fidelity, calibration, and lifecycle management represent a further gap. Digital Twins must be updated as assets, topology, control settings, market products, and resource behaviour change. Static models created for planning studies can become inaccurate when used for near-real-time operation. Distribution equivalents and aggregated DER models may fail to capture phase imbalance, protection behaviour, inverter controls, rebound effects, or correlated user responses. At transmission level, probabilistic capacity calculations depend on credible distributions of renewable output, demand, contingencies, and weather-dependent ratings. At present, there is no uniform approach within the pilots for measuring model drift, triggering recalibration, approving model releases, or documenting uncertainty across the full lifecycle.

For the abnormal market participation use case, the technical challenge lies in combining market, identity, operational, and cybersecurity data at sufficient speed and contextual depth. Labels for genuine manipulation, fraud, or erroneous behaviour are scarce, making supervised training and objective benchmarking difficult. Models trained on one market may perform poorly when transferred to another with different products, participants, or liquidity. Attackers may also adapt to known detection logic. The service therefore needs robust anomaly detection under concept drift, explainable indicators, protected evidence chains, and testing against synthetic and adversarial scenarios. False positives and false negatives must be quantified separately because their operational and legal consequences differ substantially.

For distributed resource monitoring and flexibility activation, observability and controllability remain uneven. Many small assets expose only coarse measurements or communicate through consumer-grade devices with variable availability. Asset capabilities, state of charge, comfort constraints, and local network limitations may be unknown or outdated. Aggregating thousands of devices reduces

communication overhead but can conceal locational and technical differences that determine whether flexibility is deliverable. Scalable services therefore require hierarchical estimation and control, reliable portfolio disaggregation, standard device interfaces, and mechanisms to distinguish temporary communication loss from actual resource unavailability.

For advanced transmission-capacity assessment, the main gaps concern the integration of weather data, line sensors, topology processing, and uncertainty quantification into established operational tools. Dynamic Line Rating values depend on sensor calibration, local meteorological conditions, conductor parameters, and forecast quality. Coverage may be incomplete on critical corridors, while communication loss or sensor drift can create abrupt changes in calculated capacity. Probabilistic methods add computational burden because multiple scenarios and contingencies must be solved within market and operational deadlines. Efficient scenario reduction, parallel computing, confidence reporting, and deterministic fallback procedures are required before the service can replace static limits in production.

The FFR service imposes the strictest real-time requirements. Activation within seconds requires accurate frequency and RoCoF measurements, deterministic low-latency communication, synchronised timestamps, rapid local control, and dependable acknowledgement of delivery. Cloud-centred architectures alone may be unsuitable for these timescales, making edge processing and fail-safe local behaviour necessary. Distribution-connected portfolios introduce additional uncertainty because device response, communication paths, local congestion, and rebound behaviour vary over time. High-resolution metering and event records are also needed to separate genuine service delivery from background variation and to support performance settlement.

Computational scalability and performance are common constraints across all clusters. A federated European Digital Twin cannot assume that every detailed model and dataset will be transferred to a central platform or simulated at full fidelity for each decision. Network studies, probabilistic scenarios, market clearing, anomaly detection, and DER optimisation compete for computing and communication resources. The appropriate balance among central, cloud, and edge processing has not yet been fully demonstrated under realistic operational load. Performance testing should therefore cover worst-case data volumes, simultaneous service requests, communication outages, and recovery after failure, rather than only average pilot conditions.

Cybersecurity and resilience create a further gap because federation expands the attack surface and the number of trust relationships. Compromised sensors, forged market messages, manipulated models, malicious software updates, or unavailable external services could influence decisions across organisational boundaries. Conventional perimeter security is insufficient where applications exchange data dynamically through APIs and shared platforms. Production services require strong identity management, encryption, least-privilege access, signed data and model artefacts, secure update processes, continuous monitoring, and isolation of compromised components. Resilience must also include offline operation, rollback to verified model versions, fallback to conservative limits, and recovery objectives compatible with each service's operational timescale.

Finally, validation and benchmarking are not yet sufficiently harmonised for cross-pilot replication. Each use case needs reference datasets, reproducible scenarios, common KPIs, acceptance thresholds, and comparison with established operational practice. Technical accuracy alone is insufficient: validation should measure latency, availability, scalability, explainability, cybersecurity, robustness to missing data,

and safe behaviour outside the training or calibration range. Hardware-in-the-loop and shadow-mode operation can provide evidence before live activation, but procedures and evidence packages should be comparable across pilots. Independent verification is particularly important for AI-based surveillance, probabilistic capacity outputs, DER portfolio qualification, and fast control services.

Closing these gaps requires a layered technical approach. Priority actions include establishing data-quality governance at source; adopting shared semantic profiles and persistent identifiers; defining federated discovery, access, and versioning services; implementing continuous model validation and uncertainty reporting; and designing use-case-specific edge–cloud architectures with explicit latency and resilience targets. Pilot development should progressively move from offline simulation to shadow operation and controlled live trials, using common conformance tests and failure scenarios. This would allow TwinEU to demonstrate not only functional capability, but also the reliability and interoperability required for transfer between operators and regions.

In conclusion, the main technical gap is not the absence of individual models, sensors, platforms, or algorithms, but their incomplete integration into an assured and scalable operational chain. The market-surveillance, distributed-flexibility, transmission-capacity, and FFR services all depend on trustworthy data, interoperable semantics, validated models, predictable performance, and cyber-resilient federation. Addressing these foundations is essential if pilot outputs are to become repeatable services rather than bespoke demonstrations, and it provides the technical basis for overcoming the organisational and cross-border barriers discussed in Sections 2.5.3 and 2.5.4.

3.4.3 Organizational and operational barriers

The deployment of TwinEU-enabled services requires more than validated technology and supportive regulation. It also requires organisations to change how responsibilities are assigned, how decisions are made, how operational risk is controlled, and how staff collaborate across established functional and institutional boundaries. Electricity system operators are safety-critical organisations with mature procedures, clearly separated roles, and a justified preference for predictable behaviour. Digital Twin services, by contrast, depend on continuous data exchange, rapid multidisciplinary analysis, probabilistic outputs, and coordinated action among TSOs, DSOs, market operators, aggregators, regulators, and technology providers. This creates a substantial organisational gap between the pilot environment, where partners are aligned around a defined experiment, and routine operation, where accountability, service continuity, budgets, and competing priorities must be managed over many years.

3.4.3.1 Cross-cutting governance and ownership barriers

A first barrier is the absence of an agreed business owner for many cross-domain services. A Digital Twin may be developed by an innovation department, hosted by an information technology function, validated by operational experts, and used by control-room, planning, market, or regulatory teams. If no organisational unit is accountable for the end-to-end service, decisions concerning priorities, funding, quality, cybersecurity, maintenance, and retirement can remain unresolved. Ownership is even less clear when a service spans organisations. For example, a TSO may depend on a DSO equivalent model, an aggregator's resource forecast, and a market operator's schedule, while none of these actors controls the full chain. Production deployment therefore requires named service owners, data owners, model owners, operational users, and escalation authorities, supported by a common responsibility matrix.

Organisational silos reinforce this problem. Planning, operation, asset management, market facilitation, information technology, operational technology, cybersecurity, legal, procurement, and regulatory affairs often apply different processes and risk criteria. Digital Twin services cut across these boundaries: a change to a network model can affect operational calculations; a new API can alter cybersecurity exposure; and a market algorithm can create legal or settlement implications. Sequential approval by separate departments can therefore be too slow for iterative development, while informal cooperation used during a pilot is insufficient for a critical service. Permanent multidisciplinary product teams and joint design authorities are needed to manage the complete lifecycle rather than treating the solution as a one-off IT project.

A related barrier is the difference between project and operational funding. Research pilots are financed for a limited period and are organised around deliverables, demonstrations, and partner contributions. Production services require recurring expenditure for licences, cloud or edge infrastructure, communications, data subscriptions, cybersecurity monitoring, model recalibration, user support, and upgrades to connected systems. These costs may fall across several budget centres and may not have an established approval route. If operational departments are not involved in cost estimation and procurement from the outset, a technically successful demonstrator can be left without resources for industrialisation. Total cost of ownership, internal staffing requirements, vendor dependencies, and decommissioning obligations should therefore be defined before the end of the pilot.

3.4.3.2 Decision-making, accountability, and operational risk

The services also challenge traditional decision rights. Existing procedures generally define which operator can change a limit, activate a reserve, reject a bid, or issue a control instruction. A federated Digital Twin introduces recommendations assembled from models and data outside the operator's direct control. Organisations must determine whether outputs are informational, advisory, or automatically executable; who can override them; and under which conditions the service must revert to conventional procedures. Ambiguity is particularly risky during abnormal situations, when time pressure is high and several actors may interpret the same recommendation differently. Each use case needs an operational concept that specifies authority, handover points, fallback states, alarm priorities, and responsibility for confirming the outcome.

Operator trust is another critical barrier. Control-room and market-operation staff are accountable for consequences but may have limited visibility into an AI model, probabilistic scenario set, or external data pipeline. If outputs are difficult to explain, change unexpectedly after a software release, or create excessive alarms, users may disregard them. Conversely, overreliance can develop when automation performs well under normal conditions but fails outside its validated range. Adoption therefore requires explainable interfaces, confidence indicators, comparison with existing tools, systematic recording of overrides, and recurrent exercises covering erroneous data, unavailable services, conflicting recommendations, and cyber incidents. Human factors and workload should be treated as operational acceptance criteria, not as secondary usability considerations.

Change management is complicated by the need to preserve current operations while introducing new processes. Parallel running is usually necessary, but it can duplicate work and create uncertainty about which result is authoritative. Transition plans should define entry criteria for shadow mode, controlled live operation, and full operational acceptance, together with exit criteria if performance deteriorates.

Standard operating procedures, control-room instructions, incident management, maintenance windows, and business-continuity plans must be updated in parallel with the technology. Without this organisational integration, the Digital Twin remains an additional screen or analytical report rather than a service embedded in decision-making.

3.4.3.3 Workforce, skills, and knowledge continuity

TwinEU services require combinations of power-system engineering, market design, data engineering, optimisation, statistics, artificial intelligence, software architecture, cybersecurity, and regulatory knowledge that are rarely concentrated in a single team. System operators may face difficulty recruiting and retaining specialists who can work across information technology and operational technology environments. Dependence on a small number of experts creates key-person risk, particularly when pilot researchers or external suppliers leave. At the same time, experienced operational staff may not have sufficient time to develop new digital competencies while maintaining secure daily operation.

A sustainable operating model therefore requires structured capability building rather than isolated training sessions. Role-based curricula should cover interpretation of uncertainty, data-quality assessment, model limitations, cyber-secure behaviour, and use-case-specific procedures. Joint training among TSOs, DSOs, market operators, and service providers can also build a shared vocabulary and reveal conflicting assumptions before live operation. Knowledge should be retained through documented model cards, interface specifications, operating manuals, decision logs, and reproducible test environments. Rotation between operational and digital teams can improve mutual understanding and reduce the risk that a technically sophisticated service becomes detached from actual system needs.

3.4.3.4 Operational barriers in market surveillance and distributed flexibility

For abnormal market participation detection and protocol activation, organisational separation between surveillance, market operation, system operation, cybersecurity, and regulatory investigation is a major obstacle. Each function sees only part of an incident and works to a different timescale. Cybersecurity teams may identify compromised credentials, market operators may observe unusual bids, and TSOs or DSOs may detect an emerging physical consequence. Unless information is fused through an agreed incident process, anomalies can be assessed too slowly or inconsistently. The service requires a joint triage function, severity classification, evidence-preservation rules, and a clear escalation chain. Automated restriction of participation should remain subject to authorised review, while urgent operational safeguards must be available when waiting for a complete investigation would threaten system security.

False alarms also create a practical capacity problem. Investigations require scarce legal, market, cybersecurity, and engineering expertise. If alert thresholds are set too sensitively during early deployment, teams may face an unmanageable review queue and lose confidence in the service. Conversely, aggressive filtering can conceal novel forms of abuse. Operationalisation should therefore include risk-based prioritisation, feedback from completed cases, controlled adjustment of detection logic, and performance indicators that measure investigative value rather than only the number of alerts. Access to sensitive evidence must be restricted without preventing authorised analysts from reconstructing the event across market and network domains.

For distributed resource monitoring and flexibility activation, organisational barriers arise from the scale and diversity of actors. A DSO may coordinate with several aggregators, suppliers, balance responsible parties, and technology platforms, while the TSO may require a consistent portfolio view. Onboarding, prequalification, asset registration, planned-availability updates, activation confirmation, and settlement exceptions must be handled repeatedly for large numbers of resources. Manual processes that are acceptable in a small pilot will not scale. Standard workflows, common asset identifiers, service-level agreements, and automated exception handling are necessary, together with a single point of operational contact for each portfolio.

TSO–DSO coordination also requires explicit arrangements for competing uses of flexibility. Organisations must agree who checks distribution-network feasibility, who reserves a resource, which activation takes priority, and how last-minute constraints are communicated. These rules must function outside normal office hours and during stressed conditions. A coordination platform without a staffed operational process can merely transfer uncertainty from one organisation to another. Joint procedures should therefore define response times, acknowledgement requirements, substitution rules, and escalation when the TSO, DSO, and aggregator hold inconsistent information. Periodic simulation exercises can test not only technical messages but also organisational readiness.

3.4.3.5 Operational barriers in transmission capacity and FFR services

For dynamic and probabilistic transmission-capacity assessment, the principal organisational challenge is integrating new outputs into established security-analysis and capacity-calculation processes. Control-room operators, capacity-calculation teams, market-coupling functions, asset experts, and neighbouring TSOs must share an understanding of the rating and its confidence. Dynamic Line Rating may require new responsibilities for sensor maintenance, weather-data contracts, forecast monitoring, and rapid reversion to static limits. Probabilistic calculations additionally require governance of scenario assumptions and risk thresholds. If the teams responsible for physical assets, market capacity, and real-time operation use different criteria, the additional capacity may not be released or may be withdrawn inconsistently.

The timing of capacity updates creates an operational burden as well. More frequent recalculation can improve efficiency, but organisations need sufficient staffing and automation to validate results, communicate changes, and manage exceptions within market deadlines. Capacity values should not change through an informal analytical channel; they need controlled publication, versioning, acknowledgement, and incident procedures. Regional Coordination Centres and adjacent TSOs may also need aligned operating windows and common escalation routes. Otherwise, one operator's innovative service can become another operator's unplanned operational dependency.

For FFR, the organisation must act at a timescale that excludes manual coordination during activation. Responsibilities therefore shift towards advance assurance: resource qualification, secure configuration, automated dispatch logic, local network checks, continuous availability monitoring, and post-event performance review. TSOs, DSOs, aggregators, and device operators need aligned clocks, event records, and contact arrangements for incidents. A failure affecting a large aggregated portfolio can become system-relevant even if individual devices are small. Operational procedures must cover partial delivery, communications failure, unintended rebound, simultaneous activation by different services, and restoration of resources after the event.

The procurement and settlement of FFR also introduce new work for operational and commercial teams. Portfolio changes must be reflected without repeating full qualification for every device, while maintaining assurance that aggregate performance remains valid. After an event, high-resolution data may need to be reconciled across the TSO, DSO, aggregator, and metering systems within strict deadlines. Disputes can involve both technical and contractual interpretation. Scalable deployment therefore requires automated performance assessment, predefined tolerance bands, transparent exception workflows, and clearly assigned responsibility for investigating non-delivery. These support processes are essential for confidence in the service but are easily underestimated in a pilot focused mainly on activation performance.

3.4.3.6 Supplier dependence, procurement, and service continuity

External suppliers will remain important because system operators cannot develop every analytics, platform, sensor, and communication component internally. However, conventional procurement can create organisational barriers when requirements are specified before the use case is mature or when contracts focus on delivery of software rather than operational outcomes. Proprietary models, undocumented interfaces, and restrictive licences can lock the organisation into a vendor and make independent validation difficult. Tendering and security-approval cycles can also be longer than technology-release cycles, leaving unsupported components in a critical chain. Procurement should therefore require open interfaces, portability of data and models, audit rights, vulnerability handling, long-term support, and practical exit arrangements.

Service continuity also depends on mature operational agreements. Each provider should have measurable obligations for availability, response times, incident notification, patching, backup, recovery, and support during critical events. These obligations must extend through subcontractors and external data providers. For federated services, overall availability is constrained by the weakest critical dependency, yet contracts may be bilateral and performance measures inconsistent. An end-to-end service manager is needed to monitor dependencies, coordinate incident response, and ensure that technical changes by one supplier do not invalidate models or interfaces elsewhere.

3.4.3.7 Implications for adoption and replication

These barriers indicate that exploitation should be organised as service transformation rather than technology transfer. Each TwinEU use case should leave the pilot with an operational concept, governance model, responsibility matrix, staffing plan, lifecycle budget, training package, and staged acceptance plan. Joint governance bodies should be established where data and decisions cross organisational boundaries, but they should not replace clear accountability within each participating entity. A limited number of common European templates for service-level agreements, model change control, incident escalation, and operational readiness assessment would support replication while allowing national procedures to remain compatible with local responsibilities.

A phased operating model can reduce risk. During an incubation phase, innovation teams and pilot partners remain responsible for development and evidence gathering. In a transition phase, the future operational owner assumes change control, support, cybersecurity, and continuity obligations while the service runs in shadow mode. In the production phase, performance is reviewed through normal operational governance and supplier management. At each stage, explicit readiness gates should cover people, process, data, technology, regulatory approval, and funding. This avoids the common situation in

which technical validation is completed before the receiving organisation is prepared to operate the service.

In conclusion, the organisational challenge is to convert distributed technical capabilities into a dependable operating capability shared by institutions with different mandates and risk appetites. The TwinEU use cases will scale only if decision rights, service ownership, workforce competencies, operational procedures, supplier obligations, and lifecycle resources are established alongside the algorithms and platforms. Addressing these barriers will enable the services to move from project-based collaboration to repeatable operation and will provide the institutional foundation for resolving the cross-border coordination challenges examined in Section 2.5.4.

3.4.4 Cross-border coordination challenges

Cross-border coordination is fundamental to the value proposition of the TwinEU services because electricity flows, market outcomes, balancing needs, cyber incidents, and frequency disturbances do not stop at national borders. European TSOs already cooperate through capacity calculation regions, RCCs, synchronous-area arrangements, market coupling, and balancing platforms. However, the services identified in Chapter 4 extend coordination beyond established exchanges of grid models and market schedules. They introduce real-time and probabilistic data, distribution-level equivalents, dynamic asset ratings, flexibility portfolios, anomaly indicators, and automated response protocols. The resulting challenge is to align multiple jurisdictions and organisations without undermining national operational responsibility, data sovereignty, or the speed required for secure system operation.

3.4.4.1 Multi-level governance and allocation of responsibility

A first challenge is the coexistence of several geographical and functional coordination structures. Capacity calculation is organised by region, operational security by RCC service areas and synchronous-area agreements, and balancing by pan-European platforms and national implementation arrangements. These boundaries do not always coincide. A TwinEU service may therefore require inputs from actors participating in different capacity calculation regions, market processes, or operational coordination arrangements. When a constraint spans several regions, or when a service developed in one pilot affects neighbouring systems outside its original governance perimeter, it may be unclear which body has authority to define the methodology, approve a model update, prioritise a remedial action, or resolve conflicting assessments.

National TSOs retain legal responsibility for secure operation of their control areas, while RCCs provide regional analyses and recommendations. This division can create tension when a federated Digital Twin produces a regional recommendation that exposes one TSO to greater operational risk or local cost than its neighbours. A TSO may reasonably reject the result if the underlying assumptions, external models, or confidence levels differ from its own standards. Cross-border deployment therefore requires agreed decision rights, minimum assurance criteria, an escalation mechanism for divergent results, and a record of which actor accepted, modified, or rejected a recommendation. Regional coordination must improve consistency without creating ambiguity about final operational accountability.

Governance is further complicated by different national regulatory interpretations and implementation timetables. EU network codes and guidelines establish common objectives, but detailed terms and conditions, derogations, approval processes, and operational practices can remain nationally

specific. Methodologies for capacity calculation, redispatch and countertrading, balancing, data exchange, and congestion management are implemented through multiple regional and national instruments. Changes needed for a TwinEU service may consequently require parallel approval by several regulatory authorities, TSOs, market operators, and regional bodies. Sequential consultation can take longer than the technology lifecycle, while uncoordinated national pilots risk creating incompatible solutions.

3.4.4.2 Common models, data exchange, and situational awareness

Cross-border coordination depends on a shared representation of the interconnected system. The common grid model provides a foundation for coordinated capacity calculation and security analysis by merging individual TSO models. Nevertheless, the TwinEU use cases require additional layers that are not uniformly represented: weather-dependent ratings, probabilistic scenarios, detailed inverter behaviour, distribution-network equivalents, aggregated DER capabilities, local constraints, cyber alerts, and market-participant information. If one operator uses a more detailed or more recent model than another, the same contingency can produce different conclusions. Differences in topology processing, forecast snapshots, contingency lists, remedial-action assumptions, and calculation timestamps can be as important as differences in the algorithms themselves.

Standards such as CGMES and the Regional Coordination Processes data-exchange specifications support interoperability, but conformance at file or message level does not guarantee semantic or operational equivalence. Parties may implement different standard versions, extensions, validation tolerances, identifiers, or update cycles. Digital Twin federation adds a lifecycle problem: models are continuously revised, whereas regional processes require stable, reproducible inputs for a defined calculation run. Cross-border services therefore need version-controlled model packages, common reference data, timestamp conventions, machine-readable quality indicators, and rules for determining which source is authoritative when updates conflict.

Data sovereignty and confidentiality create an additional coordination constraint. Detailed network models, vulnerability information, bids, asset availability, and consumer-derived flexibility data can be commercially sensitive or security-critical. An operator may be willing to provide an aggregated result but not the underlying dataset or modelling logic. Federation can reduce centralisation, yet partners must still agree who can query a model, for which purpose, at what granularity, and for how long outputs may be retained. Cross-border access-control policies, trusted identities, audit logs, and incident-notification procedures must function consistently among organisations governed by different national security practices. A weakest-link problem arises when one participant's identity or software-supply-chain controls are below the assurance level required by the others.

Timeliness is equally critical. Day-ahead and intraday capacity calculation, coordinated security analysis, balancing activation, and FFR operate at very different timescales. Exchanging more detailed data is useful only if it reaches all relevant parties early enough for validation and action. Latency, processing delays, maintenance windows, and unavailable external services can produce inconsistent regional views. Each service therefore requires explicit data cut-off times, acknowledgement requirements, late-data treatment, and conservative fallback rules. Otherwise, one TSO may act on an updated Digital Twin state while a neighbour continues to use an earlier version, creating avoidable operational disagreement.

3.4.4.3 Coordinated transmission capacity and remedial actions

The transmission-capacity use cases face the most direct cross-border dependency. Available capacity on an interconnector is not determined by the two border substations alone; it depends on loop flows, internal constraints, outages, generation patterns, remedial actions, and exchanges across the wider region. Dynamic Line Rating on one corridor can shift power flows towards other networks and change the critical elements used in flow-based calculation. A local increase in a thermal limit must therefore be reflected consistently in regional models, security analyses, and market domains. If neighbouring TSOs do not recognise the same rating, forecast horizon, or fallback rule, the additional capacity cannot be used safely or predictably.

Probabilistic capacity calculation raises a governance issue around risk pooling. Deterministic methods hide uncertainty within conservative margins, whereas probabilistic methods make assumptions and confidence levels explicit. Neighbouring TSOs may select different scenario-generation methods, acceptable probabilities, or treatments of rare contingencies. The safest national assumption can dominate the regional result, eliminating expected welfare benefits, while a common less-conservative threshold may be unacceptable to an operator that bears disproportionate exposure. Regional methodologies therefore need common probability metrics, calibration datasets, back-testing procedures, and rules for allocating residual risk. Uncertainty should be communicated in a form that supports decisions without creating inconsistent interpretations among control rooms and market operators.

Coordination of remedial actions is equally demanding. Redispatch, countertrading, topology changes, phase-shifting transformers, and flexibility activation can relieve a constraint in one area but create a new one elsewhere. The participating TSOs must agree which actions are available, how their effectiveness is modelled, when they become binding, and how activation and non-delivery are communicated. They must also determine how costs are shared when an action in one country benefits several bidding zones or is needed because of flows originating elsewhere. Without transparent cost-allocation and settlement rules, operators have weak incentives to make nationally funded resources available for regional optimisation.

The interaction with market deadlines presents a further challenge. Day-ahead capacities must be delivered early enough for market coupling, while intraday recalculation and balancing require progressively fresher information. A dynamic capacity increase that arrives after the relevant gate closure may have little market value, whereas a late reduction can affect firmness and require compensation or corrective action. Cross-border services need synchronised calculation cycles, common publication rules, and agreed handling of revisions after capacity has been allocated. The service must also coordinate with existing common grid model and capacity-calculation processes rather than creating a parallel result that market systems cannot consume.

3.4.4.4 Cross-border balancing, distributed flexibility, and FFR

European balancing platforms demonstrate the benefits of exchanging balancing energy across borders, but participation, national connections, and product implementation continue to evolve. The TwinEU distributed-flexibility and FFR services add resources connected deep within distribution networks and controlled through aggregators. Their cross-border use requires the importing TSO to trust qualification, availability, metering, and baseline processes performed in another jurisdiction. Differences in product definitions, bid formats, gate closures, activation logic, imbalance settlement, and portfolio

substitution can prevent a resource qualified in one country from being recognised elsewhere. Mutual recognition is difficult where DSOs apply different methods for checking local deliverability.

Capacity reservation creates another coordination trade-off. Cross-zonal capacity used for day-ahead energy trading may also be valuable for the exchange of balancing capacity, sharing of reserves, or emergency assistance. Reserving too little can prevent access to cheaper flexibility during real time; reserving too much can reduce energy-market welfare. Dynamic and probabilistic TwinEU outputs could improve this allocation, but only if TSOs use common forecasts, valuation principles, and risk assumptions. The decision must also account for whether an activated distributed portfolio can physically deliver through both its local distribution grid and the relevant cross-zonal corridor.

FFR presents an additional distinction between synchronous-area coordination and cross-border market exchange. Frequency is shared across a synchronous area, so a disturbance and the response to it are inherently regional. However, inertia distribution, system strength, credible contingencies, and available fast resources are not uniform. A common service definition must therefore be sufficiently harmonised for coordinated procurement and performance comparison, while allowing different volume and locational needs. Cross-border activation cannot depend on manual agreement after a disturbance; qualification, communication paths, trigger logic, and fallback behaviour must be aligned in advance.

Settlement and performance assessment can become contentious when the provider, metering point, aggregator, DSO, procuring TSO, and affected synchronous area are in different jurisdictions. Parties need common measurement windows, clock accuracy, treatment of missing data, tolerance bands, and exchange-rate or tax handling where relevant. They also need rules for attributing under-delivery when a resource responded correctly but a local network constraint or cross-border bottleneck reduced its system effect. Without a harmonised evidence package and dispute process, transaction costs may outweigh the value of admitting small distributed portfolios to cross-border services.

3.4.4.5 Cross-border market surveillance and incident response

Abnormal market behaviour can span bidding zones, market timeframes, and trading venues. A participant may use related entities, automated strategies, or flexibility portfolios in several countries, while each national authority sees only a fragment of the pattern. Relevant information may be held by power exchanges, nominated electricity market operators, TSOs, DSOs, aggregators, national regulatory authorities, or ACER. Cross-border detection therefore depends on linking identities and events across datasets without breaching confidentiality or prejudicing an investigation. Inconsistent identifiers, reporting thresholds, retention periods, and access permissions can delay correlation and allow coordinated behaviour to appear innocuous within each individual market.

Protocol activation is particularly sensitive. An alert generated in one jurisdiction may imply bid validation, enhanced monitoring, suspension, or an operational safeguard elsewhere. Authorities must agree when information can be shared, whether the receiving party can rely on the originating analysis, and which body leads the response. Evidentiary standards and rights of review may differ, while a premature action can distort market outcomes or reveal an investigation. The TwinEU service should therefore distinguish rapid system-protection measures from formal enforcement actions and support a tiered escalation model with secure evidence preservation, authorised human review, and clear notification responsibilities.

Cyber incidents create an overlapping coordination channel. The same event may be treated as a market-integrity concern, an operational-security incident, and an attack on critical infrastructure. Separate national reporting routes can produce duplication or gaps, particularly when evidence is classified differently. Cross-border playbooks are needed to connect market surveillance with Computer Security Incident Response Teams, system operators, and regulatory authorities. They should define common severity levels, minimum information sets, emergency contacts, and procedures for revoking compromised digital identities across connected platforms without unnecessarily excluding legitimate flexibility.

3.4.4.6 Coordination with non-EU and neighbouring systems

Several European interconnections involve Energy Community Contracting Parties, third countries, offshore systems, or synchronous areas that do not share identical EU legal obligations. Physical flows from these systems affect EU capacity calculation and security analysis even where access to data, regulatory remedies, or market platforms differs. The treatment of third-country exchanges, loop flows, outages, and remedial actions can therefore influence the capacity available within an EU region. TwinEU replication must support differentiated trust and data-access arrangements while ensuring that the regional model remains sufficiently complete for secure calculation.

Legal and commercial asymmetry can also affect service providers operating portfolios across borders. Licensing, consumer consent, metering responsibility, taxation, collateral, and access to balancing or flexibility markets may differ. An aggregator may therefore be technically capable of controlling a multi-country portfolio but obliged to operate through separate legal entities and national processes. This reduces portfolio diversity and raises transaction costs. Replication strategies should distinguish between a common technical service layer and jurisdiction-specific market participation modules rather than assuming that a single contract or registration can operate across Europe.

3.4.4.7 Implications for TwinEU deployment and replication

The cross-border challenge is therefore not solved by a single central platform. The more appropriate model is a federated service architecture combined with common governance. Local actors should retain control of detailed data and operational decisions, while regional services use agreed semantics, quality indicators, assurance levels, and interfaces. For each use case, TwinEU should define a minimum cross-border coordination package comprising participating roles, authoritative datasets, model versions, calculation and communication timelines, cybersecurity controls, decision rights, fallback procedures, and cost and liability principles.

Common testing is essential before operational use. Bilateral pilot tests should be followed by regional interoperability exercises involving TSOs, DSOs, RCCs, market operators, aggregators, and relevant authorities. Scenarios should include inconsistent model versions, delayed data, contradictory flexibility activations, dynamic rating failure, a cross-border cyber incident, and incomplete delivery of FFR. Success criteria should measure not only calculation accuracy but also common situational awareness, decision latency, traceability, safe fallback, and the ability to reconcile outcomes for settlement and regulatory review.

In conclusion, the value of federated Digital Twins emerges only when independently operated systems can reach a sufficiently consistent view and coordinate action across borders. The key gaps

concern overlapping governance structures, uneven implementation, incompatible model assumptions, restricted data access, divergent risk tolerances, and unclear allocation of costs and responsibility. Resolving them requires progressive alignment around shared assurance and operating rules rather than complete centralisation. These findings provide a direct basis for the recommendations to TSOs, regulators, and standardisation bodies developed in Chapter 6.

3.5 Recommendations and Pathways Toward Adoption

3.5.1 Recommendations for TSOs and system operators

TSOs, DSOs, market operators, and coordination entities should treat TwinEU-enabled capabilities as operational services rather than stand-alone research outputs. Chapters 3 and 4 show that the value of Digital Twins lies in connecting market, network, asset, weather, and flexibility information across organisational boundaries; Chapter 5 demonstrates that the principal adoption risk is the absence of an assured end-to-end operating chain. The recommended approach is therefore to industrialise each use case through a defined service owner, controlled lifecycle, measurable service levels, and staged transfer from pilot teams to business-as-usual functions.

First, system operators should establish an adoption portfolio with explicit priority criteria. Candidate services should be ranked according to system need, operational readiness, regulatory permissibility, data maturity, cybersecurity exposure, expected welfare benefit, and ability to scale across regions. A practical sequence is to begin with shadow-mode decision support, where Digital Twin outputs are compared with established tools, then progress to supervised operational use and finally to bounded automation. Each transition should require evidence on accuracy, availability, latency, resilience, operator workload, safe fallback, and net benefit. This avoids premature automation while preventing successful pilots from remaining permanently advisory.

Second, every service should have an operational concept and responsibility matrix. The concept should identify the authoritative datasets and models, frequency of updates, decision rights, human override, escalation routes, maintenance responsibilities, recovery objectives, and fallback conditions. For federated services, TSOs should agree service-level arrangements with DSOs, market operators, aggregators, RCCs, and technology providers. Named owners are required for source data, model versions, algorithms, cybersecurity controls, user procedures, and supplier performance. Joint governance is essential, but it must complement rather than dilute the legal accountability of each operator.

Third, operators should implement data and model assurance as a core operational discipline. Source systems should publish completeness, accuracy, timeliness, provenance, and confidence indicators appropriate to the decision timescale. Persistent identifiers and controlled semantic profiles should connect transmission equipment, distribution assets, flexibility portfolios, market registrations, and metering points. Model governance should include release approval, version control, calibration records, drift detection, uncertainty reporting, and rollback to a verified baseline. Interfaces should build on recognised CIM and CGMES foundations while extending them consistently for probabilistic scenarios, distribution equivalents, inverter controls, dynamic ratings, and flexibility products.

Fourth, system architecture should be designed around service-specific latency and resilience. Market surveillance and planning analytics may use central or cloud computing, whereas FFR and other time-

critical controls require edge processing, deterministic communication, synchronised timestamps, and fail-safe local behaviour. Capacity assessment needs redundant weather and sensor inputs, confidence thresholds, and automatic reversion to approved static limits. Operators should test worst-case data volumes, concurrent service requests, loss of communications, corrupted inputs, compromised credentials, and recovery after a failed update. Cybersecurity must apply zero-trust principles, signed data and model artefacts, least-privilege access, secure software supply chains, and continuous monitoring across organisational boundaries.

For abnormal market participation detection, operators should create a joint triage function linking market operation, system operation, cybersecurity, legal expertise, and regulatory liaison. Detection logic should combine market behaviour with physical-grid context, identity information, and data-quality signals. Alerts should be risk-ranked and explainable, with separate procedures for urgent system protection and formal enforcement. Automated restrictions should be bounded, proportionate, reversible, and subject to authorised review. Performance should be measured through precision, recall, investigation time, avoided exposure, false-alarm workload, and the quality of preserved evidence, not merely the number of generated alerts.

For distributed flexibility, TSOs and DSOs should establish a common asset and service registry, harmonised portfolio onboarding, standard availability messages, and automated prequalification evidence. A coordinated feasibility check should determine whether activation is deliverable at both distribution and transmission level. Priority rules are needed when the same resource is exposed to local congestion management, wholesale trading, balancing, and FFR; these rules should prevent double counting and define reservation, substitution, compensation, and last-minute constraint handling. Hierarchical control should preserve locational information while allowing aggregators to manage large portfolios efficiently.

For transmission capacity, operators should integrate Dynamic Line Rating and probabilistic assessments into existing security analysis rather than operate a parallel process. They should define sensor and forecast assurance, common confidence levels, treatment of missing data, and publication windows aligned with day-ahead, intraday, and balancing deadlines. Capacity increases should enter regional calculations only when neighbouring TSOs recognise the same model version and fallback procedure. Operators should compare released capacity, congestion, redispatch cost, curtailment, reliability margins, and forecast error to demonstrate whether additional utilisation creates durable system value.

For FFR, operational assurance must be completed before activation because manual coordination is impossible at the required timescale. TSOs should define technology-neutral response time, accuracy, duration, recovery, availability, and metering requirements; DSOs should validate distribution-network feasibility; aggregators should continuously maintain portfolio capability. Qualification should permit controlled substitution and statistically robust portfolio testing. Event records should support automated settlement and analysis of partial delivery, communications failure, local constraints, rebound, and overlapping activations. Procurement volumes should be informed by real-time or forecast inertia, credible contingencies, and locational effectiveness where relevant.

Finally, operators should invest in people and lifecycle capability. Permanent multidisciplinary teams should combine power-system engineering, market design, operations, data science, software,

cybersecurity, legal, and regulatory expertise. Role-based training, joint TSO–DSO exercises, model cards, decision logs, reproducible test environments, and rotation between operational and digital teams will reduce key-person and vendor dependence. Total cost of ownership should include communications, computation, licences, data services, recalibration, incident response, support, and decommissioning. Contracts should require open interfaces, audit rights, vulnerability management, data and model portability, and practical exit arrangements. These measures provide a credible pathway from demonstration to dependable operation.

3.5.2 Recommendations for regulators and policy makers

Regulators and policy makers should create a framework in which validated Digital Twin outputs can influence markets and operations without weakening accountability, consumer protection, competition, or system security. The 2024 Union electricity-market reform strengthens the policy role of flexibility, while revised market-integrity arrangements increase expectations for surveillance in increasingly automated markets. The next step is to translate this direction into approved methodologies, investable remuneration, proportionate market access, and enforceable coordination rules applicable across Member States.

First, regulatory authorities should define assurance requirements for Digital Twin-supported decisions. A common framework should distinguish informational, advisory, supervised, and automated uses. For each class, it should specify validation evidence, data-quality thresholds, model documentation, independent testing, explainability, cybersecurity, auditability, human oversight, incident reporting, and conservative fallback. Liability should follow control and negligence rather than being left ambiguous across operators and suppliers. Regulatory sandboxes can permit bounded experimentation, but they should require representative data, live operational interfaces, consumer and market safeguards, and a documented route to permanent approval.

Second, incentive regulation should recognise digitalisation and flexibility as alternatives or complements to conventional reinforcement. Efficient expenditure on sensors, communications, Digital Twin platforms, data services, cybersecurity, flexibility procurement, and staff capability should be recoverable when supported by transparent business cases. Output-based incentives can reward reduced redispatch, avoided curtailment, improved connection capacity, faster restoration, and higher utilisation of existing assets, while penalties and review mechanisms protect consumers from ineffective expenditure. Benefit-sharing arrangements are needed where national investments create regional welfare or where implementation risk falls on one operator but benefits accrue to multiple actors.

Third, market-access rules should be proportionate and technology-neutral. Minimum bid sizes, symmetry, duration, telemetry, collateral, and prequalification requirements should reflect the physical purpose of the service rather than legacy generator characteristics. Aggregators need a clear legal role, transparent relationships with suppliers and balance responsible parties, portfolio-level qualification, and manageable imbalance exposure. Small resources should be able to participate through aggregation without duplicative registration. At the same time, qualification must verify locational deliverability and account for distribution-network constraints.

Fourth, regulators should harmonise baseline, measurement, and settlement principles for distributed flexibility. Acceptable baseline families, validation datasets, manipulation controls, uncertainty disclosure,

and dispute procedures should be defined while allowing use-case-specific methods. Digital Twin-derived baselines should be independently tested and periodically recalibrated. Common rules are also needed for asset substitution, non-delivery, rebound, simultaneous service commitments, and compensation when a DSO restriction prevents an otherwise valid activation. This will lower transaction costs and improve confidence without prescribing a single algorithm.

For surveillance, regulation should distinguish an analytical suspicion from a legal finding. Local flexibility platforms should be subject to minimum monitoring, identity, reporting, retention, and evidence-preservation obligations aligned with wholesale market-integrity principles. A tiered protocol should separate immediate system-protection measures from investigation and enforcement, preserve rights of review, and identify when information must be shared with national authorities and ACER. Funding should protect the independence of surveillance: regulated cost recovery or competitively procured services with strict confidentiality safeguards are preferable to charging subjects of monitoring for discretionary compliance treatment.

For dynamic and probabilistic capacity calculation, regional methodologies should define acceptable confidence levels, sensor redundancy, forecast quality, calibration, late-data treatment, and fallback to static ratings. Rules should clarify when revised capacity becomes firm, how reductions after allocation are managed, and how costs of remedial actions are shared. Approval processes should enable controlled updates as models improve, rather than requiring a complete methodology redesign for each technical release. Regulators should assess performance using long-term back-testing and realised security outcomes, not isolated maximum-capacity gains.

For FFR, policy makers should support a harmonised product family across synchronous areas while permitting regional volumes and technical parameters. Decisions are needed on separate or co-optimised procurement with FCR and other reserves, dynamic sizing based on inertia and credible contingencies, cross-zonal capacity treatment, and mutual recognition of qualification. Settlement rules should use common timing, accuracy, and evidence requirements. Regulatory treatment should avoid technology prescriptions and allow batteries, controllable demand, EV fleets, and inverter-based generation to compete when they deliver verifiable system value.

Fifth, data governance should be made operational. National and regional rules should define lawful purposes, minimum datasets, granularity, retention, confidentiality, data-quality responsibility, intellectual-property treatment, and access rights for TSOs, DSOs, market operators, regulators, aggregators, and qualified technology providers. Federated exchange should be favoured where it reduces unnecessary centralisation, but trusted identities, audit logs, incident notification, and sanctions for misuse must be consistent. Consumer-derived data should be protected through purpose limitation, minimisation, and transparent consent or other lawful bases.

Sixth, European and national authorities should streamline coordinated approval. Joint regulatory work programmes can align sandboxes, regional methodologies, and implementation timetables for services that cross borders. Common templates should cover data-sharing agreements, model assurance, prequalification evidence, service contracts, incident reporting, and cost-benefit analysis. Mutual recognition should be used where assurance outcomes are equivalent, particularly for portfolio qualification and technology conformity. Coordination with neighbouring and Energy Community systems should separate a common technical layer from jurisdiction-specific participation modules.

Finally, policy evaluation should use transparent and comparable indicators. Regulators should monitor system security, market liquidity, participation diversity, redispatch and balancing costs, curtailment, connection delays, service availability, cyber incidents, false surveillance alerts, and distributional effects on consumers. Sunset and review clauses should allow underperforming arrangements to be corrected without removing regulatory certainty for investment. The objective is not to mandate Digital Twins as a technology, but to create outcome-based rules under which assured digital services can compete fairly with conventional solutions and scale where they provide demonstrable European value.

3.5.3 Recommendations for further research and standardization

Further research and standardisation should focus on the gaps that prevent technically successful pilots from becoming interoperable, assured, and repeatable services. The priority is not another collection of isolated algorithms, but evidence and specifications for the entire value chain from source data to an operational or market decision. Research programmes should therefore combine power-system science, market design, human factors, cybersecurity, data engineering, and regulatory experimentation, and should use common validation artefacts that can be reused across TwinEU pilots and subsequent European projects.

A first priority is a shared reference architecture for federated energy-system Digital Twins. It should define functional layers for data acquisition, semantic mediation, model management, simulation, optimisation, trust, service orchestration, and user interaction. The architecture should support local autonomy, selective disclosure, and deployment across edge, operator, cloud, and regional environments. Research should establish which information must be exchanged, which computations can remain local, and how confidence and provenance propagate when one twin consumes another twin's output.

A second priority is semantic interoperability. Existing CIM, CGMES, IEC 61850, and market-message standards should be profiled and extended for distribution equivalents, DER portfolios, inverter and grid-forming controls, flexibility products, probabilistic scenarios, weather-dependent ratings, anomaly indicators, and Digital Twin lifecycle metadata. Standardisation bodies should favour modular application profiles, persistent identifiers, explicit units and temporal conventions, machine-readable quality attributes, and backward-compatible versioning. Public conformance tests and reference implementations should verify semantic equivalence rather than only file syntax.

A third priority is data and model quality. Common metrics are needed for completeness, accuracy, timeliness, provenance, uncertainty, and fitness for purpose. Research should determine how these metrics map to day-ahead planning, real-time operation, market settlement, and sub-second control. Model lifecycle standards should cover calibration, drift, uncertainty, version approval, reproducibility, rollback, and retirement. Equivalent distribution models and aggregated DER models require particular attention because their validity depends on topology, operating point, portfolio composition, control behaviour, and the intended service.

Validation research should create cross-pilot benchmark suites. Representative datasets and scenarios should cover ordinary operation, stressed conditions, missing and delayed data, topology errors, sensor drift, cyber compromise, model transfer between regions, and simultaneous service use. Metrics should include accuracy, latency, availability, scalability, explainability, robustness, operator workload, safe

fallback, and economic value. A staged evidence ladder should progress from offline simulation through co-simulation and hardware-in-the-loop to shadow operation and controlled live trials. Independent replication and red-team testing should be expected for safety-critical or enforcement-related applications.

For market surveillance, research should address rare labels, concept drift, coordinated behaviour across markets, adversarial adaptation, and explainability. Synthetic market and cyber ranges can generate controlled examples without exposing confidential investigations. Benchmarking should separate false positives, false negatives, detection delay, and investigative usefulness. Standards are needed for anomaly-event schemas, identity linkage, evidence provenance, confidence scoring, and secure exchange among market operators, system operators, regulators, and incident-response teams. Methods should be assessed for fairness and proportionality so that new or small participants are not systematically over-flagged.

For distributed flexibility, research should improve observability at low voltage, probabilistic flexibility envelopes, baseline methods, portfolio disaggregation, local deliverability, and coordinated activation across services. Device and gateway interfaces should expose capability, state, constraints, availability, and response acknowledgement in a consistent manner while respecting privacy. Standard portfolios and test procedures should address batteries, EVs, heat pumps, industrial demand, distributed generation, and mixed assets. Qualification methods should scale statistically while preserving evidence of geographic relevance and aggregate reliability.

For transmission capacity, research should compare deterministic, probabilistic, and robust optimisation methods using common corridors and historical conditions. Dynamic rating studies should combine conductor physics, sensor placement, weather nowcasting, forecast uncertainty, ageing, and maintenance implications. Regional benchmarks should examine how different risk thresholds alter market welfare, redispatch, curtailment, and security. Standard outputs should include the rating, validity interval, confidence, sensor and forecast status, limiting assumption, and approved fallback, enabling capacity-calculation and market systems to consume the result consistently.

For FFR, further work should define a harmonised but configurable product model covering trigger, response time, accuracy, duration, recovery, directionality, availability, measurement, and location. Research should quantify service need under varying inertia, system strength, credible contingencies, and converter controls. Co-simulation should link electromagnetic and frequency dynamics, transmission and distribution constraints, communications, market procurement, and portfolio behaviour. Standardised testing should include aggregated and grid-forming resources, partial communications failure, rebound, repeated events, and interaction with FCR, aFRR, protection, and local congestion management.

Cyber-resilient federation should be a horizontal research theme. Specifications are needed for cross-organisational identities, signed datasets and models, secure APIs, attestation of software and device state, privacy-preserving computation, and rapid revocation of compromised credentials. Research should evaluate how federated learning, secure enclaves, differential privacy, and aggregated queries can support collaboration without exposing unnecessary raw data. Security testing should include supply-chain compromise, malicious model updates, forged telemetry, denial of service, and cascading loss of trust between twins.

Finally, research outputs should be managed for adoption. Open benchmark datasets should be anonymised or synthetic where confidentiality prevents publication; algorithms should be accompanied by reproducible configurations, model cards, uncertainty statements, and deployment requirements. Standardisation roadmaps should assign topics to the appropriate European and international bodies and coordinate with regulatory methodology development. TwinEU should maintain a living gap register and interoperability profile, updated from pilot evidence. This will ensure that research closes identified barriers and that standards evolve from demonstrated operational needs rather than abstract completeness.

3.5.4 Outlook toward exploitation and replication

The exploitation outlook for TwinEU is strongest when the project's outputs are packaged as modular services that can be adopted independently but share a common federated foundation. Chapters 3 and 4 identify five business cases across four service clusters; Chapter 5 shows that replication depends on coordinated progress in technology, regulation, organisation, and cross-border governance. The recommended pathway is therefore portfolio-based and phased, combining local value creation with progressively broader interoperability and market integration.

Exploitation should begin by defining a service package for each use case. The package should contain the value proposition, target users, core and optional functions, required inputs, interfaces, assurance evidence, deployment architecture, operating model, regulatory prerequisites, commercial model, KPIs, and support obligations. Components should be separated into reusable layers: trusted data exchange, model management, analytics, decision support, activation, settlement, and reporting. This modularity allows an operator to adopt a lower-risk analytical capability before enabling control or market functions and reduces dependence on a single platform supplier.

A four-stage replication pathway is proposed. Stage 1 is evidence consolidation: pilots complete benchmark testing, quantify benefits, document failures, and produce reusable specifications. Stage 2 is operational incubation: a receiving operator runs the service in shadow mode with production-like data, cybersecurity controls, support, and user procedures. Stage 3 is controlled deployment: the service influences bounded decisions under explicit approval, fallback, and regulatory conditions. Stage 4 is regional scaling: interfaces, qualification, and governance are aligned among several operators, relevant RCCs or market platforms, and regulators. Readiness gates should cover value, people, process, data, technology, cybersecurity, regulation, and finance at every stage.

Replication sites should be selected for learning value rather than convenience alone. A useful portfolio combines similar sites, where transferability can be tested with limited change, and contrasting sites, where differences in topology, market design, data maturity, DER penetration, and regulatory practice reveal adaptation needs. Each site should perform a baseline assessment, map local actors and systems, identify mandatory localisation, and estimate integration and lifecycle costs. A replication scorecard can compare data readiness, semantic compatibility, operational sponsorship, regulatory route, cybersecurity maturity, availability of flexible resources, and expected system benefit.

The exploitation model will differ by cluster. Market surveillance is primarily a regulated public-interest capability, best supported through operator or authority budgets and competitively procured technology with strong independence and confidentiality. Distributed flexibility can combine regulated DSO

functions, market-platform fees, aggregator services, and performance-based remuneration to asset owners. Capacity assessment is principally an internal TSO or regional coordination service justified by avoided redispatch, reduced curtailment, and deferred reinforcement. FFR is suited to competitive procurement, with providers earning availability and performance revenues while operators fund qualification, activation, and settlement infrastructure.

Value measurement should be designed before deployment. A common framework should distinguish operator value, market and societal value, provider value, and enabling value. Relevant indicators include avoided operating expenditure, released capacity, reduced redispatch and curtailment, deferred investment, improved forecast and detection performance, faster incident response, increased flexibility participation, service availability, cybersecurity resilience, and lower integration cost for the next site. Counterfactual baselines and uncertainty ranges should be published internally so that benefits are not overstated and investment decisions remain comparable.

Cross-border exploitation should build on existing European processes rather than create a parallel institutional layer. Capacity and security services should integrate with common grid model, capacity-calculation, and RCC workflows; balancing and FFR services should align with European balancing platforms and synchronous-area arrangements; surveillance should connect local and national signals with REMIT reporting and authorised cooperation. A minimum federation agreement should define the authoritative model version, message and quality profiles, calculation timetable, access controls, decision rights, incident procedures, fallback, liability, and cost allocation.

Intellectual property and procurement should promote an ecosystem rather than lock-in. Project partners should distinguish reusable standards and interfaces, reference implementations, operator-specific models, proprietary algorithms, and confidential datasets. Open interfaces, exportable configurations, documented APIs, and portable data and model artefacts should be mandatory for critical services. Commercial competition can remain around analytics, implementation, managed operations, and support. Joint procurement or framework agreements among operators can reduce duplication, while conformance certification can enable smaller technology providers to enter the market.

A sustainable exploitation organisation is also required. TwinEU should establish a post-project service catalogue, owner for each exploitable result, maintenance and release policy, support contact, training package, and repository of validated profiles and test cases. A community of practice involving TSOs, DSOs, market operators, regulators, aggregators, vendors, and research organisations can collect implementation evidence and coordinate updates. Annual interoperability exercises should test model exchange, delayed data, contradictory activations, cyber incidents, dynamic-rating failure, and FFR non-delivery across organisational boundaries.

In the short term, the priority is to complete assurance evidence, nominate receiving organisations, quantify lifecycle costs, and prepare shadow-mode deployments. In the medium term, selected services should enter regulated sandboxes or controlled market trials, with mutual recognition of selected conformance and qualification results. In the longer term, successful services should be incorporated into approved European methodologies and standard procurement or operational processes. Scaling should remain conditional on demonstrated security and value: replication is not the duplication of a pilot, but the disciplined transfer of a service with known adaptation boundaries.

Looking ahead, TwinEU can support a transition from siloed, deterministic, and asset-centred operation toward federated, probabilistic, and service-oriented coordination. The most credible exploitation pathway combines conservative operational assurance with ambitious interoperability, clear public-interest governance with competitive service provision, and local autonomy with agreed regional rules. If these conditions are met, the project's business cases can move from bespoke demonstrators to a repeatable European portfolio that improves market integrity, unlocks distributed flexibility, uses transmission assets more efficiently, and stabilises low-inertia systems.

3.6 Conclusions

3.6.1 Summary of Findings

This deliverable examined how Digital Twin-enabled services can address structural limitations in current European electricity-system business models. Chapters 3.2 and 3.3 showed a common transition across the selected TwinEU use cases: from static, centralised, sequential, and asset-centred arrangements toward dynamic, federated, probabilistic, and service-oriented coordination. Five business cases were consolidated within four service clusters: market surveillance and integrity; distributed-resource monitoring, coordination, and flexibility activation; advanced and probabilistic transmission-capacity assessment; and Fast Frequency Response. Although their technical functions differ, all depend on trusted data exchange, interoperable models, coordinated decision-making, and a credible route from analytical output to an operational or market action.

The analysis confirmed that Digital Twins can create value both through new market-facing offers and through internal operational improvements. In market surveillance, combining bidding behaviour with network, identity, and cybersecurity information can support earlier and more contextual detection of abnormal participation. For distributed flexibility, federated transmission and distribution models can improve observability, portfolio qualification, local deliverability checks, and coordinated activation. Dynamic Line Rating and probabilistic capacity calculation can release additional transmission capability while improving anticipation of congestion and uncertainty. FFR can convert the speed of batteries, controllable demand, electric vehicles, and inverter-based generation into a structured ancillary service for low-inertia systems.

However, Chapter 3.4 demonstrated that technical functionality is not sufficient for adoption. Regulatory recognition of probabilistic or automated outputs, proportionate market access, cost recovery, liability, data rights, and cross-border approval remain incomplete. Technical gaps include uneven distribution-grid observability, inconsistent semantics and identifiers, model drift, limited benchmark evidence, stringent latency requirements, and an expanded cybersecurity attack surface. Organisational barriers include fragmented ownership, unclear decision rights, insufficient lifecycle funding and skills, supplier dependence, and the need to integrate new services into established operational procedures. Cross-border implementation further requires common models, risk thresholds, publication timelines, qualification evidence, incident protocols, and cost-allocation principles.

Chapter 3.5 therefore proposed adoption as a staged service transformation rather than a direct transfer of pilot technology. The central requirements are a named service owner, an operational concept, measurable readiness gates, data and model assurance, secure edge–cloud architecture, human oversight, conservative fallback, and continuous benefit measurement. Regulators should complement

this with outcome-based incentives, technology-neutral product rules, regulatory sandboxes, harmonised measurement and settlement, and mutual recognition where assurance outcomes are equivalent. Research and standardisation should prioritise reference architectures, semantic profiles, reusable benchmark suites, and cyber-resilient federation.

Overall, TwinEU provides a credible basis for improving market integrity, activating distributed flexibility, using existing transmission assets more efficiently, and maintaining frequency stability as renewable and inverter-based generation increases. Its lasting value will depend on whether pilot results are packaged as modular, assured, and interoperable services that receiving organisations can operate and finance over their full lifecycle. Replication should therefore be judged not by the number of copied demonstrations, but by demonstrated security, measurable system and societal value, lower integration effort at subsequent sites, and successful incorporation into routine European operational and market processes.

3.6.2 Recommendations

The immediate priority is to convert the most mature TwinEU results into bounded operational services. TSOs, DSOs, market operators, and pilot owners should select use cases through transparent criteria covering system need, data maturity, cybersecurity exposure, regulatory feasibility, expected welfare, and replication potential. Each selected service should first run in shadow mode, then progress to supervised use and only later to bounded automation. Advancement should depend on demonstrated accuracy, availability, latency, resilience, operator workload, safe fallback, and net benefit.

Every deployment should establish an accountable service owner and a cross-organisational responsibility matrix. Authoritative datasets, model versions, decision rights, human override, escalation, maintenance, recovery, and fallback must be agreed before live operation. For federated services, these arrangements should be formalised through service-level agreements among TSOs, DSOs, RCCs, market operators, aggregators, regulators, and technology providers. Permanent multidisciplinary teams and recurrent joint exercises are needed to maintain operational competence and reduce dependence on individual experts or suppliers.

Data and model assurance should be implemented as a continuous operational process. Common identifiers and semantic profiles should connect grid assets, DER portfolios, market registrations, metering points, probabilistic scenarios, dynamic ratings, and flexibility products. Critical exchanges should include quality, provenance, timestamp, confidence, and version information. Models should be subject to calibration, drift detection, release approval, rollback, and independent validation. Architecture should reflect the service timescale: central or cloud analytics may support planning and surveillance, while FFR requires edge control, deterministic communication, synchronised event recording, and fail-safe local behaviour.

Regulators should create an investable and proportionate route to deployment. Efficient expenditure on sensors, communications, Digital Twin platforms, cybersecurity, flexibility procurement, and staff capability should be recoverable where benefits are demonstrated. Market rules should be technology-neutral and permit aggregation, portfolio qualification, controlled substitution, and participation by smaller resources, while preserving locational deliverability and consumer protection. Regulatory

sandboxes should test contracts, settlement, liability, data governance, and operational interfaces as well as algorithms, and should define a clear route to permanent approval.

Implementation priorities should remain use-case specific. Market surveillance needs risk-ranked and explainable alerts, secure evidence preservation, human review, and separation between urgent system protection and formal enforcement. Distributed flexibility requires common asset registries, scalable onboarding and prequalification, coordinated feasibility checks, robust baselines, and priority rules for overlapping commitments. Transmission-capacity services require assured sensors and forecasts, agreed confidence levels, harmonised publication windows, and automatic reversion to static limits. FFR requires a technology-neutral product definition, continuous portfolio capability management, distribution-network validation, dynamic sizing, and automated performance assessment and settlement.

TwinEU should support replication through reusable service packages containing interfaces, assurance evidence, operating models, regulatory prerequisites, KPIs, lifecycle costs, training, and support arrangements. Replication should proceed from evidence consolidation to shadow operation, controlled deployment, and regional scaling. European coordination should build on existing common grid model, RCC, capacity-calculation, balancing, and market-integrity processes rather than create parallel structures. Common conformance tests, interoperability exercises, and model assurance templates should be maintained after the project.

Finally, exploitation decisions should be based on transparent counterfactuals and a balanced set of indicators: security, service availability, released capacity, redispatch and curtailment, market liquidity, flexibility participation, detection quality, incident response, integration cost, and distributional effects. In the short term, partners should nominate receiving organisations and complete assurance evidence; in the medium term, mature services should enter controlled trials; in the longer term, validated services should be incorporated into approved European methodologies and routine procurement. This disciplined pathway offers the best prospect of converting TwinEU's demonstrators into dependable and scalable European services.

4 Impact assessment on pan-European system planning and operations (T9.5)

4.1 Introduction

4.1.1 General Introduction on Impact Assessment

TwinEU's Task 9.5 is dedicated to **assessing the impact of the use cases and technologies demonstrated across the project on the strategic planning and operational management of the future pan-European power system**. Building on the observations gathered from the various TwinEU demonstrators, spanning economic, environmental, security-of-supply and resilience dimensions, this task translates these local, demonstration-scale insights into pan-EU system-wide conclusions. Thus, this task's goal is to determine how the approaches explored in TwinEU could benefit the pan-European electricity system.

Within this broader impact assessment exercise, this part focuses specifically on the economic dimension: quantifying how the digital-twin-enabled use cases studied in TwinEU affect the costs of the pan-European energy system. Such technological solutions could be expected to improve the system's economics, mainly expressed through the concepts of system costs and social welfare. This economic lens is a natural entry point, along which most of the use-case-level KPIs defined across the TwinEU demonstrator (congestion costs, redispatch volumes, curtailment, or welfare gains from increased market participation ...) ultimately need to be interpreted at system scale.

System costs and social welfare are two complementary readings of the same underlying quantity in a market-clearing framework. Under the assumption of an efficient, welfare-maximizing market design, minimizing the total system cost of serving demand (which accounts to the sum of generation, redispatch, curtailment and unserved-energy costs) is equivalent to maximizing the social welfare generated by the system, defined as the sum of consumer and producer surplus. In practice, this means that a use case which reduces curtailment or improves the utilisation of existing assets translates directly into a measurable system cost reduction

TwinEU's eight demonstration pilots taken together generate a very large and heterogeneous body of use cases: around fifty use cases have been developed across these pilots, each associated with its own set of KPIs, combining both the fifteen project-wide KPIs defined in the Grant Agreement and a large number of use-case-specific KPIs defined by each pilot. Those use cases have been summarised and analysed during the first working days of task T9.5 (see Figure 1).

As many of them share the same underlying economic mechanism even though they are demonstrated through different technologies or in different countries, it has been chosen to evaluate a fewer number of cases rather than thoroughly modelling all of them.

A/A	PILOT	UC ID	UC TITLE
1	Bulgarian	BG01	Establishment of the data exchange between the Digital Twins
2		BG02	AI-Improved Forecast of WPP Production
3		BG03	AI-Improved Forecast of SPP Production
4		BG04	AI-Improved Forecast of OHL Ampacity
5		BG05	Increase of power flow on cross border transmission lines
6		BG06	Determination of optimal locations for RES connection
7		BG07	N-1 assessment on the DT level
8		BG08	DT-based Maintenance plan of TSO grid
9		BG09	Flexibility Requirements to Avoid Congestions
10		BG10	Inter-SO Flexibility Exchange
11	Dutch/ French	NI01	DT-enabled real-time cyberattack impact analysis on the operation of integrated power grid
12		NI02	DT-based dynamic stability assessment under active power flow changing events.
13		FR01	Power system training simulator for complex and critical situations
14	EAST-MED	EM-CY-01	Congestion management in distribution grids through ancillary services
15		EM-CY-02	Frequency support management of HVDC-interconnected systems in a regional level
16		EM-GR-01	Congestion management in transmission and distribution grids through TSO-DSO coordination
17		EM-GR-02	Fast Frequency Response for Effective Frequency Control through TSO-DSO coordination
18	German	Ge01	Utilization monitoring on LV-level
19		Ge02	State estimation under changing topology on LV-level
20		Ge03	Development of advanced monitoring & control tools for congestion management
21		Ge04	Development of a concept for a preventive congestion management
22		Ge05	Optimal utilization of the flexibility potential in the network feeder by aggregation of flexible assets within the household via HEMS
23		Ge06	Development of advanced tools for preventive congestion management through regional aggregation of flexible assets
24		Ge07	Conceptual description of interoperable solutions that support an efficient TSO-DSO data exchange on the interface level.
25		Ge08	Connection request and online connection check applications for the DSO, TSO as well as for third parties.
26	Hungarian	DT1	Digital twin for power line monitoring
27		HU02	Co-optimizing the day-ahead and intraday energy and balancing capacity market
28		HU03	Enhanced flow-based capacity calculation for market co-optimization using DLR data
29	Iberian	Ib01	AI Agent for probabilistic grid status forecast and remedial actions identification for the TSO's Control Center Operator
30		Ib02	DT for generation of synthetic series of renewable resources
31		Ib03	DT-enabled multi-area system dynamic behaviour assessment
32		Ib04	Abnormal market participation detection and protocol activation for mitigating the risk and consequences
33		Ib05	DT-based N-1 contingency analysis
34		Ib06	DT-enabled new RES integration validated plan in the MV grid
35		Ib07	DT-based grid maintenance planning activities
36		Ib08	DT self-discovering and debugging based on IA
37		Ib09	Optimal planner for massive DERs deployment (EV, PV) at the LV Grid
38		Ib10	Advanced Planner for LV Operation
39		Ib11	Long term flexibility in MV
40		Ib12	Flex Connections
41		Ib13	Probabilistic cross-border capacity allocation
42		Ib14	Cross-border assessment of flexibility and pre-qualification
43		Ib15	Integration of TSO-DSO-MO-Prosumer coordination schemes as well as market coordination
44		Ib16	Enhancement of short-circuit models and TSO/DSO information exchange for operational planning
45		Ib17	DT-endorsed flexible connection grant through the settlement of a LFM to internally balance the production surplus in congestion-creation hours/scenarios
46	Italian	IT01	Analysis through DT of the TSO defence system
47		IT02	Analysis through DT of the behaviour of aggregated distributed resources during a grid event in the TSO system
48		EACL-IT-01	Digital Twin for definition of data model
49		EACL-IT-02	Digital Twin for design validation
50		EACL-IT-03	Scalability of Digital Twin for design validation
51	Slovenian	SLO-UC-1	Dynamic RMS Analysis with Upgraded Transmission System Model
52		SLO-UC-2	Real-time Dynamic RMS Analysis with Transmission System Model improved with the dynamic parameters of generators and control models of the neighbouring TSO
53		SLO-SUC	Power system analysis tool retrieves operational data from SCADA/EMS

Figure 1 - Use cases list drawn during preliminary works for task T9.5

To make the exercise operational, the use cases were therefore reorganised into a small number of transversal themes: families of use cases which, despite differing in their technological implementation, are expected to affect the pan-European system through a common set of mechanisms, and can consequently be assessed with a shared modelling and extrapolation approach. This classification, building on the segmentation work initiated in WP2 and refined, resulted in the selection of seven transversal themes, split between the two partners according to their respective capabilities. This segmentation echoes, while not strictly mirroring, the four use cases recently proposed by ENTSO-E and DSO Entity in their joint report on TSO-DSO Digital Twin Use Cases [1]: consumer-centric flexibility, hosting-capacity-oriented network planning, resilience to high-impact low-frequency events, and coordinated security assessment. Where the ENTSO-E/DSO Entity taxonomy is organised around TSO-DSO coordination processes, the seven themes chosen here isolate more mechanism-specific technologies

(e.g. Dynamic Line Rating, Fast-Frequency Response, Forecast Accuracy) chosen for their ability to be extended to a shared pan-European modelling and extrapolation approach:

- Themes of **Forecast Accuracy**, **Grid Hosting Capacities**, **Dynamic Line Rating**, and **Grid Monitoring**, are treated with pan-European dispatch simulations, using the Artelys Crystal Super Grid platform;
- Themes of **Strategic Planning**, **Local Flexibility Markets**, and **Fast-Frequency Response** are treated via benchmark.

For each theme, the underlying use cases and associated KPIs were reviewed to define a set of extrapolation hypotheses, i.e. assumptions on how a demonstration-scale improvement (e.g. an accuracy gain, a capacity increase, a reduction in outages) can reasonably be generalised to the whole pan-European system, together with the modelling approach best suited to translate this hypothesis into evolution of system costs. The remainder of this introduction presents the modelling framework used to carry out this translation, before the deliverable turns, theme by theme, to the detailed methodology, hypotheses and results of each of them.

Table 9: Overview of the seven transversal themes, their lead partner and the TwinEU demo inputs used

Transversal theme	Involved Partners	TwinEU demo input used
Forecast Accuracy	Pan-EU dispatch simulation	Bulgarian pilot (UC BG02, BG03 – wind/solar forecast accuracy); Iberian pilot AI grid-status forecasting agent
Grid Hosting Capacities	Pan-EU dispatch simulation & Benchmark	VITO literature review on flexible connection agreements and distribution-grid reinforcement needs
Dynamic Line Rating	Pan-EU dispatch simulation	Hungarian pilot demonstrator (UC HU02 – DLR-related KPIs)
Grid Monitoring	Pan-EU dispatch simulation	No single demonstrator directly measures the benefit; generic maintenance-day-reduction hypothesis used instead
Strategic Planning	Literature benchmark	No TwinEU demo input directly used in the benchmark
Local Flexibility Markets	Literature benchmark	No TwinEU demo input directly used in the benchmark
Fast-Frequency Response	Literature benchmark	No TwinEU demo input directly used in the benchmark

4.1.2 Introduction to the methodology used in T9.5

4.1.2.1 Pan-European dispatch simulations to assess benefits on system

The core of the T9.5 impact assessment methodology is to bridge the gap between the evidence generated at demo-case level and the assessment of impacts at pan-European system level. The results of the demo cases are extrapolated to the European level. The resulting estimates are then translated into modelling assumptions that capture the expected performance improvements or operational effects of the solutions considered. Beyond this shared dispatch methodology, every theme-specific study in this report is anchored to the same common scenario framework, the TYNDP 2024 NT+ scenario, detailed below, ensuring that the system-cost, welfare and emissions impacts estimated for each solution remain directly comparable.

The **TYNDP 2024 scenario cycle** [2], jointly developed by ENTSO-E and ENTSG, comprises different scenarios covering the 2030, 2035 and 2040 and 2050 horizons, all built out from a single 2030 starting point: the National Trends+ (NT+) scenario. NT+ is the central, policy-based scenario as it reflects Member States' national energy and climate plans (NECPs) and national long-term strategies, and is calibrated so that the EU aggregate remains consistent with the Union's 2030 climate and energy targets, with any residual gap closed through the published NT+ Energy Mix gap-filling methodology. **This study adopts the 2030 NT+ scenario as its baseline** as it is the scenario most representative of currently adopted national policies, giving a consistent, EU-wide reference for demand, generation mix and interconnection capacity in the near future, against which the impacts of TwinEU's use cases and demos are assessed.

The NT+ 2030 scenario has been implemented within the **Artelys Crystal Super Grid framework** (see Section 4.1.2.2), which serves as the modelling backbone of the pan-European electricity system. Data from the TYNDP scenario cycle such as the following has been integrated within the modelling tool:

- Generation assets characteristics (from the PEMMDB [2] database) such as generation capacity, costs ...
- Weather years 2009, 2008 and 1995 (which are canonical in the TYNDP cycle) and underlying meteorological data and demand profiles from the PECD [3] database
- Scenario-wide hypotheses and techno-economic parameters such as fuel costs, technology costs (e.g. for solar panels, used in section 4.3)
- Hydrogen-system related data, in order to notably represent the flexibility offered by the combined optimisation of the coupled energy systems

European electricity network topology (at the bidding zone level) and transmission capacities within nodes. On this basis, the system undergoes yearly simulations that optimise dispatch at an hourly resolution which is a granularity fine enough to capture the effects of the TwinEU technologies under study and the resulting reduction in system costs.

Concretely, this hourly optimal dispatch is computed over a system modelled as a set of interconnected bidding zones, each aggregating generation, demand, storage and cross-border exchange capacity at that granularity. For every simulated hour, the optimisation determines the dispatch of all available generation and flexibility resources (thermal units, renewables, storage, etc.) together with the resulting cross-zonal exchanges, so as to minimise total system cost subject to the technical and network constraints described throughout this section, whether expressed under the standard NTC/ATC representation or, where

relevant, under Flow-Based Market Coupling. Solving this optimisation hour by hour, over a full year yields the optimal dispatch: the allocation of production, storage operation and cross-border exchanges that best meets demand at least cost given the system's technical and market constraints. This optimal dispatch is the common analytical backbone of the study as every transversal theme is assessed by comparing the system cost, welfare, emissions and other indicators it produces.

4.1.2.2 Artelys Crystal Super Grid: a modelling tool for energy dispatch simulations

Artelys Crystal Super Grid [4] is a web-based solution dedicated to the modelling and optimisation of energy systems. The tool allows its user to combine models of generation, consumption, transmission and storage via modular “assets”, allowing to take into account **specific constraints for every asset** (e.g., thermal generation constraints, management of hydro power plants, variability of renewable generation, properties of flexible demand, etc.). Assets can be represented at unit or fleet level.

The solution supports **flexible geographical resolution**, from entire countries to subnational regions or interconnected bidding zones, which allows for a bidding zone-level representation of the pan-European energy (interconnected electricity and H2 systems) system.

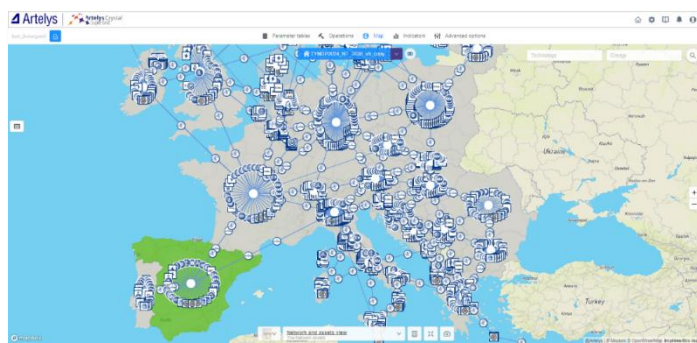


Figure 2 - European model in Artelys Crystal Super Grid GUI (based on TYNDP 2024 NT+ scenario)

The solution optimises generation dispatch by minimising overall system costs. This optimisation follows the "merit order" logic, whereby generation assets are dispatched from the cheapest to the most expensive, while simultaneously accounting for key factors such as the role of flexibility solutions (e.g., battery storage or pumped-hydro storage), cross-zonal flow limits due to interconnection capacities, and more. With appropriate constraints, **the model can also represent the functioning of power systems where specificities deviate from the traditional “merit-order” logic**, e.g. via must-run constraints, limited fuel budget constraints, etc. System constraints can also be used to force exchanges between producers and consumers, reflecting underlying contractual agreements.

The software also incorporates advanced, specific models to simulate complex market mechanisms and reflect real-world market constraints and incentives, which will be used in this study and are presented below:

Flow-Based Market Coupling

Flow-Based Market Coupling (FBMC) represents **cross-zonal exchange capacity through the physical constraints of the network**, rather than through a single commercial value per border as in the NTC/ATC approach. Feasible net positions are bounded by a set of Critical Network Elements with Contingencies (CNECs), each limited by its Remaining Available Margin (RAM), i.e. the capacity left once reference flows and security margins are accounted for.

Dynamic Line Rating (DLR) is a technology that allows to **adjust the thermal limit according to real time conditions** (ambient temperature, wind ...), instead of applying a fixed, conservative rating. Since the thermal limit is a direct input of the RAM, a change in line rating propagates element by element into the capacity offered to the market, which an NTC/ATC representation captures less by construction. **FBMC is therefore the natural framework to assess the market value of DLR**, providing a framework that translates dynamically the varying line rating into physical constraints. As CNEC, PTDF and RAM datasets are demanding to build and maintain, it is used for the DLR theme only. All other themes rely on NTC/ATC.

Monte-Carlo applied to interconnector outages and maintenance module

Within the Grid Monitoring theme, interconnector unavailability is represented through two complementary components. **Planned maintenances** are set by a scheduling algorithm that places planned outages in the periods where the margin between available capacity and net demand is most favourable, yielding a single schedule applied to all climate years. **Forced outages** are then handled by a Monte-Carlo module: for each draw, a random outage pattern calibrated on historical statistics is added to this schedule, and the dispatch optimisation is solved.

This combination is used because the duration and timing of interconnector outages vary widely across historical records. Relying on a single outage pattern would risk penalising some interconnectors because of an unusually unfavourable draw. By averaging over a large number of draws, the Monte-Carlo approach smooths out such extreme realisations and provides both the expected value and the dispersion of the KPIs.

4.1.2.3 Specific literature review on connected topics

In parallel with the modelling activities presented in this deliverable, a complementary benchmark analysis is performed on selected topics related to distributed flexibility. The objective of this analysis is to complement the quantitative modelling with evidence from existing studies, network planning practices and real-life operational implementations. In doing so, the benchmark aims to provide additional context for the interpretation of the modelling results and to identify approaches and practices that may be transferable across the different TwinEU use cases.

The benchmark addresses the role of distributed flexibility from both the DSO and TSO perspective and covers three main dimensions: the availability and characteristics of flexibility resources, the integration of flexibility in strategic network planning, and the operational use of flexibility by system operators.

More specifically, the analysis focuses on the following topics:

- **Flexibility resources and grid reinforcement for DSOs**, including the assessment of flexibility potential from relevant distributed resources and the review of distribution grid reinforcement needs under increasing electrification and renewable deployment;
- **Strategic planning**, including the integration of distributed flexibility into Network Development Plans and other planning processes, the assessment of current and future flexibility needs, and methodologies used to compare flexibility solutions with conventional grid investments;
- **Operational management by DSOs**, focusing on Local Flexibility Markets used for congestion management and voltage control, as well as Flexible Connection Agreements;

- **Operational management by TSOs**, focusing on innovative system services and, in particular, Fast Frequency Response services and the participation of distributed flexibility resources in these services.

For each of these topics, the analysis first provides a concise review of the relevant literature and current state of practice. This is followed, where appropriate, by a more detailed assessment of selected representative cases and available quantitative indicators.

Methodological approach

Considering the scope and timeline of the project, the benchmark does not aim to provide an exhaustive EU-wide assessment. Instead, a targeted case-study approach is applied, focusing on representative and relevant examples that can provide broader lessons for TwinEU. The selection of cases is therefore not restricted to TwinEU demonstration countries. Priority is given to jurisdictions and system operators for which sufficiently detailed information is publicly available and, where possible, to mechanisms that have already been implemented in real-life operational environments.

The benchmark is primarily based on desk research and consequently relies on publicly available information. The analysis therefore reflects the level of detail and transparency provided by system operators, regulators, market operators and other relevant organisations. Where quantitative information is not publicly reported, the analysis is limited to qualitative findings or indicative estimates derived from existing studies.

The main sources considered include:

- previous academic studies, technical studies and European or national reports;
- Transmission and Distribution Network Development Plans (TNDPs and DNDPs);
- adequacy studies and flexibility needs assessments;
- publications resulting from common DSO-TSO initiatives;
- methodologies and guidance documents published by system operators and regulators;
- market rules, product sheets, terms and conditions and procurement documentation;
- market results and operational performance indicators published by system operators and flexibility market platform providers; and
- regulatory reports and other publicly available monitoring information.

4.2 Forecast Accuracy

4.2.1 Methodology and assumptions

This section explains how the two scenarios compared throughout this study are built. A statistical model, calibrated on historical European data, first generates a realistic reference forecast error for load and renewable generation. **The forecast error reduction measured by the TwinEU Bulgarian pilot is then applied on top of this reference to build an improved-forecast scenario. Comparing European system operation between the two scenarios isolates the system-wide impact of this accuracy gain.**

4.2.1.1 Grounding the forecast error reduction hypothesis in TwinEU KPIs

The TwinEU project demonstrates, at pilot scale, that AI-based forecasting tools can meaningfully improve the accuracy of renewable generation forecasts. In the Bulgarian pilot, use cases BG02 and BG03 train an artificial neural network on historical wind and solar power plant production data, paired with high-resolution local weather forecasts. The resulting model is tested on a separate, unseen period, and its accuracy is compared against a reference forecast. This training and testing cycle is repeated until a satisfactory level of accuracy is reached, and the associated KPI captures the resulting gain in forecast accuracy for wind and solar production respectively. A comparable logic is followed in the Iberian pilot, where an AI agent is developed to improve the accuracy of probabilistic grid status forecasts for the TSO control centre operator (Ib01).

The KPIs, namely the improvement in WPP and SPP forecast accuracy, are reused as the reference magnitude for the forecast improvement considered in this study. To translate this improvement into the simulation framework, the forecast error generation methodology described below is used. It reproduces the statistical properties of forecast errors on load and renewable generation from historical data. Comparing European system operations under both forecast error scenarios makes it possible to assess the impact of extrapolating this accuracy gain to solar and wind forecasts across every European bidding zone.

4.2.1.2 Forecast errors generation methodology

Forecast errors are the deviation between forecasted and actual values of load and renewable generation. They arise from market participants' imperfect access to real-time operational information at the time of market participation. As these errors are, by construction, unpredictable residuals, the module used to create them does not attempt to forecast them directly. Instead, it reproduces their statistical properties (variance, temporal correlation and dependence on production level and meteorological regime) as observed in historical data. Errors are normalized by installed capacity for renewable generation and by yearly mean demand for load, allowing consistent modeling across technologies and bidding zones.

A simulated forecast is reconstructed as $\widehat{Prod}_{t,h}^{z,j} = Prod_{t,h}^{z,j} - \varepsilon_{t,h}^{z,j}$, where $Prod_{t,h}^{z,j}$ is the actual normalized production or demand and $\varepsilon_{t,h}^{z,j}$ the simulated forecast error (for each bidding zone z , feature j (load, solar, onshore/offshore wind) and forecast horizon h given for time t).

For Day-Ahead forecasts, the error is modelled as the sum of three components: $\varepsilon_{t,DA}^{z,j} = Bias_{t,DA}^{z,j} + \sigma_{t,DA}^{z,j} \cdot Y_{t,DA}^{z,j}$.

The bias term ($Bias_{t,DA}^{z,j}$) captures regime-dependent systematic errors via a Hidden Markov Chain over meteorological regimes. The residual amplitude ($\sigma_{t,DA}^{z,j}$) is constant for demand and, for renewable generation, follows a power-level regression with coefficients fitted per bidding zone. The temporal correlation term ($Y_{t,DA}^{z,j}$) follows a standardized AR(1) process $Y_{t,DA}^{z,j} = a_{DA}^{z,j} \times Y_{t-1,DA}^{z,j} + \epsilon_{t,DA}^{z,j}$ whose residual is truncated at each step to keep the forecast within physically feasible bounds.

All parameters were estimated using ENTSO-E Transparency Platform data from January 2018 to July 2025, with some adjustments to ensure consistency in the modelling. Thus, the simulated errors and the simulation results reflect forecasting performance as accurately as possible.

4.2.1.3 Expected impacts of a forecast error on system operation and economics

Forecast errors on load and renewable generation directly affect both the technical operation and the economic efficiency of the power system. Operationally, larger or less predictable errors increase the volume of balancing energy that TSOs must procure to compensate for the deviation between scheduled and actual injections. They drive higher reserve requirements to maintain system security. They can also lead to more frequent and costly redispatch and curtailment actions, particularly in zones with high renewable penetration or limited grid flexibility. Economically, forecast errors translate into imbalance costs borne by market participants under imbalance settlement mechanisms. At system level, they also translate into higher balancing market prices and volumes which are ultimately passed on to consumers. From an environmental perspective, this also leads to higher emissions, as more thermal power stations are brought into operation to compensate.

4.2.1.4 Reducing forecast error

Technologies that improve forecast accuracy by reducing the amplitude, bias, or persistence of forecast errors are expected to lower balancing costs and reduce reserve procurement needs. They are also expected to improve overall market efficiency, with benefits that scale with the share of variable renewable generation in the system.

For this study, a scenario with reduced forecast errors on solar and wind production was built based on the results of the Bulgarian pilot. Thus, to model the improvement in forecast accuracy across all European bidding zones, forecast errors on solar production were reduced by 1.92%, and forecast errors on wind production were reduced by 3.91%. This allows to directly compare simulation results between a reference scenario, using the original forecast error, and an improved scenario, reflecting the higher forecast accuracy achieved for both technologies.

4.2.2 Simulation results and analysis

4.2.2.1 System costs

Table 10: Change in European system costs with a better forecast accuracy, across different climatic years (in M€)

Climatic year	Basecase Scenario (M€)	Improved forecast Scenario (M€)	Δ (M€)	$\Delta\%$
1995	66,993	66,111	-882	-1.3%
2008	66,093	65,415	-678	-1.0%
2009	73,920	73,251	-669	-0.9%
Average	69,002	68,259	-743	-1.1%

Table 10 compares system costs under the Intraday dispatch with the original forecast-error draw against the same dispatch with a reduced forecast error, for each of the three climatic years and on

average. **Reducing forecast error lowers system costs in every single year** with an average reduction of 743 M€/year (–1.08%). The magnitude of the reduction is materially stable across years which is itself informative: this is a structural effect of forecast quality on redispatch cost.



Figure 3 - Map of the change in European system costs with a better forecast accuracy for the average across climatic years, aggregated by country

The system-wide average above masks a strongly uneven geographic distribution. Mapping the change in system costs by country shows the improvement is heavily concentrated rather than spread evenly across Europe. Poland accounts for –591 M€, about 70% of the total cross-country magnitude of change, with Italy (–52 M€), Germany (–39 M€), Spain (–30 M€) and the United Kingdom (–25 M€) forming a distant second tier. Just 3 of the 35 mapped countries are needed to explain 80% of the total magnitude. These countries are the most exposed to Intraday redispatch.

Proportionally, the countries most affected by improved forecast accuracy are smaller or interconnection-dependent systems rather than the largest markets. Luxembourg tops the ranking, with a 10% reduction in system costs relative to the reference scenario. Poland follows closely at –9.3%, confirming that its large absolute savings shown in Figure 4 also translate into one of the highest relative gains in Europe. Estonia (–6%) and Malta (–3.2%) complete the group of countries most exposed to forecast accuracy improvements.

This pattern suggests that smaller systems, or systems that rely heavily on imports and limited domestic flexibility, benefit disproportionately when forecasting is more accurate across the European system. In these systems, the 2% to 4% reduction in forecast error (which are the hypotheses of the model) removes a comparatively large share of the balancing and redispatch costs needed to manage renewable variability.

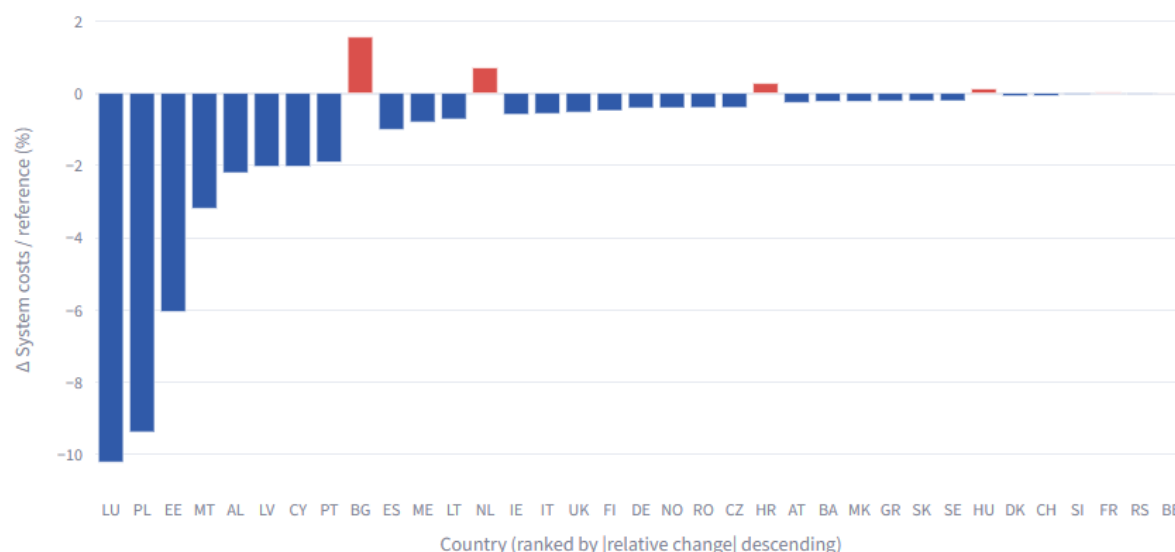


Figure 4 - Relative change in system costs by country (% vs. reference scenario)

4.2.2.2 CO₂ emissions and curtailment

Table 11: Change in European CO₂ emissions and total curtailment with a better forecast accuracy, across different climatic years (in M€)

Climatic year	CO ₂ baseline (Mt)	CO ₂ reduced (Mt)	Δ CO ₂ (Mt)	Curtailment baseline (TWh)	Curtailment reduced (TWh)	Δ Curtailment (TWh)
1995	149.4	148.4	-1.0	166.0	164.3	-1.7
2008	144.8	143.9	-0.9	163.4	162.2	-1.2
2009	165.3	164.3	-1.0	157.9	156.4	-1.5
Average	153.2	152.2	-1.0	162.4	161.0	-1.4

CO₂ emissions and curtailment (Table 11) show the same consistent direction as system costs: a reduced forecast error lowers CO₂ emissions by an average of 1 Mt per year (-0.65%) and curtailment by an average of 1.4 TWh per year (-0.87%), again in every climatic year individually. A less-error-prone forecast means the system needs less corrective redispatch to reconcile the Day-Ahead plan with reality, which is precisely the corrective machinery that both burns extra fuel (CO₂) and forces more renewable output to be spilled (curtailment) when it has to act on a larger deviation.

A small number of countries, including Bulgaria, the Netherlands and Croatia, show a slight cost increase rather than a reduction. This counter-intuitive result could be expected, a more accurate forecast in interconnected zones can shift production plans or import and export flows and marginally increase costs in specific systems, without altering the overall downward trend observed across Europe.

4.2.2.3 Climatic-year sensitivity

Testing several climatic years matters because renewable generation, and the forecast errors linked to it, are highly weather-dependent. A single year could reflect an atypical wind or solar pattern rather than the true effect of improved forecasting. Running the same scenario across multiple climatic years isolates the structural impact of better forecast accuracy from normal weather variability, and shows whether benefits are consistent or amplified in years with higher renewable variability.

For system costs, the improved forecast scenario delivers a reduction in every climatic year tested, ranging from -0.9% in 2009 to -1.3% in 1995, against a -1.1% average reduction across years. CO₂ emissions and curtailment follow the same pattern, with emissions falling by around 1.0 Mt and curtailment by 1.2 to 1.7 TWh depending on the climatic year considered. While the absolute magnitude naturally shifts with each year's weather conditions, the direction and order of magnitude of the impact remain stable, and no climatic year produces a divergent or unexpected result.

4.2.2.4 Open Cycle Gas Turbines (OCGT) commitment under forecast error

A forecast error changes how often the thermal fleet is committed for short-duration interventions. Open Cycle Gas Turbines are among the fastest-starting thermal units on the system and are commonly dispatched to cover an unexpected shortfall in renewable output or demand. A poor forecast tends to produce more short on/off cycles, an OCGT started up and shut down again within one or two hours. Counting these short cycles per country, and comparing their number between the original and the reduced forecast error scenarios, shows an effect that is geographically heterogeneous.

Table 12: Variation of the number of startups followed by a shutdown after 1 or 2 hours, summed by country, for the average across climatic years

Country	Δ OCGT quick startups
SE	+3
FI	+2
FR	+1
MT	0
LT	-5
LU	-5
UK	-5
HU	-5
CZ	-10
AT	-13
DE	-16
CY	-78

Table 12 shows the number of times OCGTs were switched on and then off for a period of up to 1 or 2 hours. Not all countries are included in this table, but it shows that most systems benefit from a marked reduction in avoidable short-cycling once the forecast is improved. Cyprus is standing out by a wide margin

(–78 cycles), followed by Germany (–16), Austria (–13), and the Czech Republic (–10). This pattern is consistent with systems where OCGT units are called upon to compensate for renewable forecast deviations, so that a more accurate forecast directly reduces the need for rapid, short-duration start-stop operation. Conversely, a small number of countries move in the opposite direction, with Sweden, Finland and France showing a slight increase in quick startups under the improved forecast. This counter-intuitive outcome likely reflects a different local generation mix, where OCGT units play a more marginal, opportunistic role. Indeed, these are the three countries with the highest proportion of nuclear power in their energy mix. Therefore, a better forecast slightly reshuffles the merit order and dispatch pattern rather than reducing the overall need for fast-response capacity. It may also point to cross-border effects, whereby a more accurate forecast in neighbouring or interconnected zones alters import and export flows, in turn changing the residual load that OCGT units are called upon to cover in these particular systems (see section 4.2.2.5).

The graphs below show concrete examples of periods lasting a few days during which OCGTs are used differently at national level, depending on whether the forecast is good or poor.

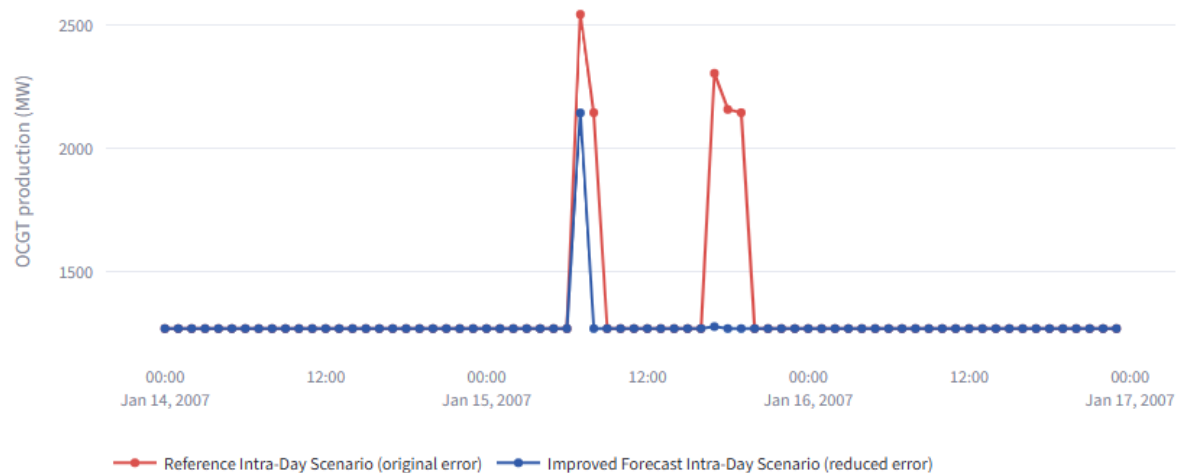


Figure 5 - Example of different OCGT productions in France with a better forecast accuracy

On January 15 (climatic year 1995), the French OCGT fleet produces markedly more under the original error scenario than under the reduced error one at two points in the day: the morning (7am: +399 MW, 8am: +874 MW) and the evening (5pm: +1026 MW, 6pm: +887 MW, 7pm: +874 MW).

On January 1 (climatic year 2009), the German OCGT fleet was already running a large constant base load. It produces significantly more under the original forecast error scenario at four separate points in the day: mid-morning (9am: +2,966 MW), midday (1pm: +2,086 MW) and the evening peak (4-6pm, peaking at 5pm: +7,524 MW).

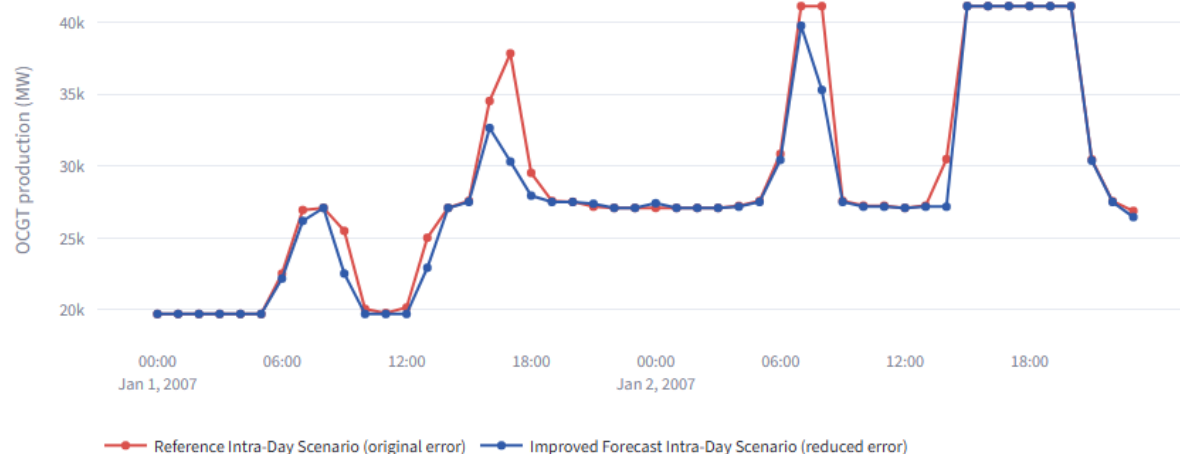


Figure 6 - Example of different OCGT productions in Germany with a better forecast accuracy

4.2.2.5 Flexibility provision by non-thermal levers: batteries, hydro and cross-border exchanges

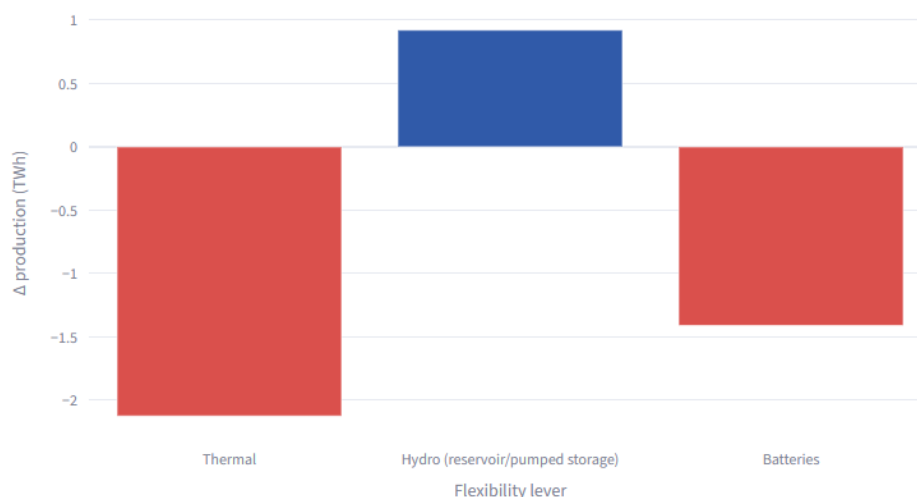


Figure 7 - Change in EU-wide actual production by flexibility lever, improved forecast vs. reference scenario (average across climatic years)

Figure 7 shows the EU-wide change in actual production by flexibility lever between the improved forecast scenario and the reference scenario, averaged across climatic years. Net cross-border exchange is deliberately excluded here, as it sums to close to zero across the EU by construction, one country's import being another's export.

At EU scale, a more accurate forecast reduces thermal production by around 2.1 TWh and battery production by around 1.35 TWh. Hydro production increases by close to 0.9 TWh. The system shifts away from costly, wear-intensive levers like thermal towards cheaper hydro balancing. The reduction in battery activity is consistent with the average decrease of 236 charge/discharge cycles per year observed across Europe, confirming that a better forecast directly eases the operational strain on short-duration storage assets.

Country-level view: Poland, the Netherlands and France

The following figure breaks the analysis down for three countries chosen for their contrasting system-cost outcomes: Poland, which shows a –9.4% average reduction in system costs, against the Netherlands, whose system costs slightly increase (+24.5 M€, a 0.7% rise), and France, which remains very close to 0%.

Hydro refers to reservoirs and pumped storage, exchange refer to net cross-border exchanges.

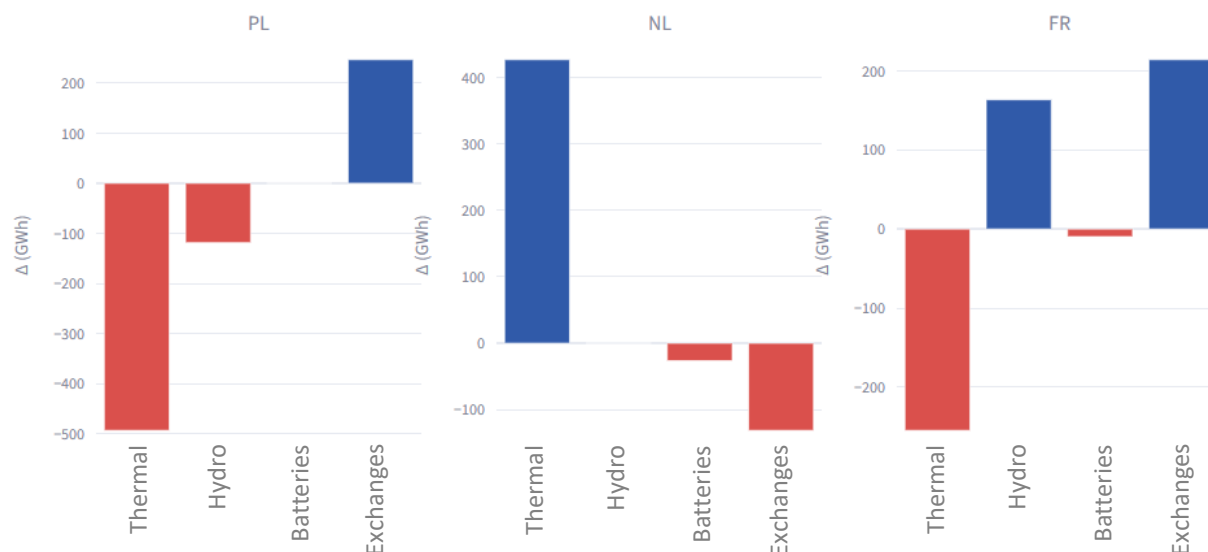


Figure 8 - Change in actual production and cross-border exchange by flexibility lever, improved forecast vs. reference scenario, for Poland, the Netherlands and France (average across climatic years)

Poland shows the largest and most structured adjustment of the three countries. Consistent with its sharp reduction in system costs: thermal production falls by close to 480 GWh, offset by a marked increase in net cross-border exchange of around 250 GWh, meaning Poland relies more on imports once its own forecast improves. The Netherlands shows the opposite pattern, with thermal production increasing by around 430 GWh and net cross-border exchange falling by around 100 GWh, suggesting a shift towards more net exports. France sits between these two profiles, with thermal production decreasing by around 230 GWh and net cross-border exchange rising by around 210 GWh, pointing to increased net imports. This combination mirrors the Polish pattern on a smaller scale, even though the near-zero impact on French system costs suggests these adjustments broadly offset one another rather than generating a net economic gain. Overall, the contrast between these three countries confirms that the value of forecast accuracy improvements, and the way flexibility is redistributed across levers, depends strongly on each country's specific generation mix, storage capacity and interconnection profile, and cannot be assumed uniform across Europe.

4.2.3 Conclusion on forecast accuracy for system costs

Reducing forecast error on solar and wind production in line with the accuracy gains already demonstrated by the Bulgarian pilot lowers European system costs by 1.1% on average, in every one of the three climatic years tested, together with a 0.65% reduction in CO₂ emissions and a 0.87% reduction

in curtailment. The improvement also reduces avoidable short-cycling of OCGT units in most countries, and shifts the system away from costly thermal balancing towards cheaper hydro flexibility.

This benefit is concentrated rather than uniform. Poland alone accounts for about 70% of the total cross-country change, and the countries that gain the most, proportionally, are smaller or import-dependent systems such as Luxembourg and Poland rather than the largest markets. A handful of countries, including the Netherlands, see a small cost increase instead, as a more accurate forecast reshapes cross-border flows in ways that are not uniformly favourable. Thus, if comparable forecasting tools were deployed across the whole European system, the impact will be significant when considering the European system as a whole, but structurally, the distribution of costs will not be uniform or proportional to the size of the market.

4.3 Grid Hosting

4.3.1 Introduction

The growing penetration of decentralised renewables and the electrification of usages are placing increasing pressure on European distribution grids, which were not originally designed to host large volumes of variable generation. Reinforcing these networks is often the structural solution, but it takes years and money to plan and build. Flexible Connection Agreements (FCAs) can offer a faster, cheaper alternative in the meantime. With these agreements, new renewable capacity can connect today, in exchange for accepting occasional curtailment during the network's most constrained hours.

In this section, a literature review documents distribution-grid flexibility needs and reinforcement plans across Europe. It also benchmarks how FCA mechanisms are deployed today, mostly using real data from the United Kingdom. Building on this, a pan-European dispatch-model analysis was developed to quantify how much FCA and grid reinforcement increase renewables hosting capacity, alone and combined.

The distributed-flexibility and network-constraint themes reviewed here directly echo several TwinEU pilots built around this exact challenge: the Bulgarian pilot with use case BG06, *“Determination of optimal locations for RES connection”*, the German pilot (notably GE08, *“Visualizing hosting capacities within connection request and online connection check applications”*), the Iberian pilot with IB06, *“DT-enabled new RES integration validated plan in the MV grid”*, IB09 : *“Optimal planner for massive DERs deployment (EV, PV) at the LV grid”* and IB12 *“Flex Connections”*, as well as the East-Med pilot more broadly. The pan-European study of Task T9.5 can be read as extrapolating these pilots' logic. The objective is determining where, and how much, renewable capacity a constrained grid can host, and what role flexible connection arrangements play, to a full European scale.

4.3.2 Literature review

4.3.2.1 Flexibility resources and distribution grid reinforcement

4.3.2.1.1 Objective and scope

The increasing penetration of decentralised renewable generation and electrification of transport, heating and industry are increasing and reshaping electricity demand and power flows on European

distribution grids [5]. Electric vehicles (EVs), heat pumps (HPs), battery storage and other distributed resources can increase local peak demand, but many can also adjust their consumption or injection and therefore provide flexibility to support Distribution System Operators in managing network constraints.

This analysis reviews flexibility resources relevant to distribution grid operation, focusing on their potential deployment, availability and accessibility in near-term European scenarios to around 2030–2035. It also examines DSO assessments of flexibility needs and evidence on distribution grid reinforcement requirements in selected European countries and DSO areas.

4.3.2.1.2 Analytical framework

The analysis considers the relationship between flexibility and distribution grid development from three complementary perspectives.

First, the *Flexibility resources and potential in the DSO context* subsection considers the flexibility that distributed resources such as electric vehicles, heat pumps and batteries could provide. It reviews both the expected deployment of these technologies and, where available, estimates of the flexibility they could provide. It also considers the aggregated contribution of residential and small-commercial resources and the extent to which flexibility from different customer segments is practically accessible to DSOs. These dimensions are not equivalent: a large installed or deployed asset base, or a substantial flexibility potential, does not necessarily translate into the same amount of flexibility being accessible at a particular time or network location.

Second, the *DSO flexibility needs* subsection considers the network demand for flexibility. It examines the magnitude and, where reported, the location, timing, duration and direction of flexibility that could be required to manage projected distribution network constraints. This perspective is necessary because aggregate flexibility potential can only contribute to a specific network constraint if suitable resources are located behind the constrained network element and can respond when required.

Third, the *Distribution grid investments and the role of flexibility* subsection considers the flexibility resources and network needs discussed above in the broader context of distribution grid development. It reviews the scale and drivers of expected grid reinforcement and examines how flexibility is treated in these investment assessments. Where quantified, the analysis also considers the extent to which higher flexibility could reduce or defer reinforcement. The evidence shows that flexibility can moderate some investment needs, but that substantial network expansion remains necessary under expected electrification and distributed generation scenarios.

The reviewed studies do not always use flexibility terminology in the same way. A reported value may, for example, represent technical potential, flexibility available under specific assumptions, or a flexibility contribution at a particular time. This analysis therefore retains the terminology of the original sources and explains what each reported value represents where needed. More broadly, it distinguishes between the flexibility that resources could provide, the flexibility that DSOs require to manage network constraints, and physical grid reinforcement.

4.3.2.1.3 Methodological approach and evidence base

The assessment was conducted as a desk-based review of European and national regulatory and industry studies, flexibility assessments, DSO investment and network development plans, and selected

analytical studies. Primary sources from network operators, regulators and public authorities were prioritised.

Key European references include the ACER–CEER *Guidance on electricity distribution network planning* (2025) [6], Eurelectric/E.DSO/Monitor Deloitte's *Connecting the dots* (2021) [7], Eurelectric/EY's *Grids for Speed* (2024) [30], JRC's *DSO Observatory 2024: Unlocking flexibility in Europe* [8], ACER's *Unlocking flexibility: No-regret actions to remove barriers to demand response* (2025) [9], and the ACER–CEER *Rewarding flexibility: How retail contract choice can help unlock consumer flexibility* (2025) [10]. Country- and DSO-level evidence from Belgium, the United Kingdom, the Netherlands, France, Denmark, Portugal, Sweden and Spain was reviewed where relevant to the respective analytical perspective.

The cases were selected based on the relevance, quality and availability of quantitative and qualitative evidence for the three perspectives considered in the analysis. For flexibility resources, preference was given to studies reporting near-term deployment or quantified flexibility estimates for EVs, heat pumps, batteries and other relevant distributed resources. Selected evidence was also included on the aggregated contribution of residential and small-commercial resources and on the practical accessibility and mobilisation of flexibility across customer segments. For DSO flexibility needs, the review focused on network development plans and regulatory assessments that quantify constraints potentially addressable through flexibility. ACER and CEER identified Denmark, Portugal, Slovenia and Sweden as the countries in which the assessed Distribution Network Development Plans included quantified flexibility needs, which guided the selection of cases for this part of the analysis. Additional DSO evidence was included where it provided useful quantified information on residual or location-specific network constraints. For grid reinforcement, studies were selected where they provided quantitative evidence on expected investment, physical network expansion or the potential effect of flexibility on reinforcement requirements.

The resulting evidence is heterogeneous in geographic coverage, time horizon, methodology and terminology. Reported values are therefore interpreted according to the definitions and assumptions of the original sources rather than treated as directly comparable indicators. The country and DSO cases are intended to provide complementary illustrations of the scale and characteristics of flexibility resources, network needs and reinforcement requirements, rather than a harmonised or statistically representative estimate for Europe.

4.3.2.1.4 Flexibility resources and potential in the DSO context

Flexibility relevant to distribution system operation can be provided by a range of distributed resources. This subsection focuses on the resource side of flexibility: the deployment of potentially flexible technologies and the flexibility they could provide. The main resources considered are electric vehicles, heat pumps and other thermally flexible loads, and stationary batteries. These technologies differ in their expected deployment, controllability and ability to shift or modify consumption or injection over time.

The amount of flexibility associated with these resources depends on the assumptions and conditions considered in each study. Installed or deployed capacity should therefore not be interpreted directly as flexibility available to a DSO. The contribution of a resource to a specific network constraint depends on factors such as its location in the network, controllability, availability at the required time, duration of response and whether its capacity is committed to other uses or services. Because the studies quantify flexibility in different ways, each reported value is interpreted according to the assumptions and definition

used in the original source. The underlying studies use different scenarios, modelling approaches and assumptions. These are not described in full; only those elements necessary to interpret the reported flexibility values and their limitations are highlighted. Readers seeking further methodological detail are referred to the original studies cited for each example.

The following subsections use selected European, national and regional studies to illustrate the scale and characteristics of flexibility from the main resource types. The examples are not intended to provide directly comparable estimates, as they differ in geographic scope, time horizon, methodology and assumptions. An aggregated residential and small-commercial example is also included, followed by evidence on how readily flexibility from different customer segments is currently accessible to DSOs. The subsequent DSO flexibility needs subsection then shifts the perspective from what flexibility resources could provide to the flexibility that distribution networks may require to manage specific constraints.

Electric vehicles

EV charging is expected to become a major new electricity load on European distribution networks [5]. Its flexibility is primarily associated with shifting charging in time while satisfying users' mobility and state-of-charge requirements. The EV flexibility therefore depends on factors including vehicle connection and departure times, required charging energy, charger capacity, user behaviour and the ability to control charging [11].

Evidence from several European countries indicates substantial potential by 2030, although the reported quantities differ considerably in definition.

In Belgium, Elia's *Adequacy and Flexibility Study for Belgium 2026–2036* [12] assumes approximately 1.2 million flexible EVs by 2030. The contribution of EVs at a given time is considerably more limited: under Elia's central scenario, EVs provide on average approximately 131 MW of upward and 452 MW of downward fast flexibility by 2036, although maximum contributions can approach 800 MW in favourable periods.

France provides a different operational benchmark. RTE's 2026 *Baromètre des flexibilités de consommation d'électricité* [13] sets a 2030 trajectory under which controlled EV charging avoids approximately 3.5 GW of consumption at 19:00 and shifts approximately 4.3 GW towards 14:00. The trajectory assumes that more than 80% of home and workplace charging is controlled by 2030. These are national electricity-system targets rather than DSO-specific flexibility quantities, but they demonstrate the potentially material scale of managed EV charging.

In Great Britain, the 2025 *Clean Flexibility Roadmap*, prepared by DESNZ, Ofgem and NESO [14], provides another useful near-term benchmark. The government's Clean Power 2030 pathway targets 10–12 GW of consumer-led flexibility by 2030, referring broadly to flexibility provided by households and businesses through controllable demand and behind-the-meter assets, including EV charging, batteries, heating and appliances. NESO's FES Holistic Transition scenario gives a corresponding total of 10.3 GW of consumer-led flexibility, including 2.7 GW from smart EV charging and 1.2 GW from vehicle-to-grid operation.

For the Netherlands, TNO's COMPETES analysis assumes 1.5 GWe of EV flexibility in the CA2030 demand response case [15]. TNO explicitly notes that most demand response capacity parameters are set exogenously in the model. The value therefore represents an assumed system-level capacity and not

observed or contracted DSO flexibility. TNO nevertheless finds that demand response from EVs, heat pumps, hybrid boilers and power-to-hydrogen could collectively reduce total annual Dutch power-system flexibility demand by around 16% in 2030.

Taken together, the studies indicate that EVs are likely to constitute a significant near-term flexibility resource. They also demonstrate why EV fleet size, or charger capacity should not be treated directly as flexibility available to DSOs. Only the subset of vehicles that is connected downstream of a constrained network element, controllable at the relevant time and able to postpone or modify charging can contribute to resolving that constraint.

Heat pumps and other thermally flexible loads

Heat pumps have a dual effect on distribution networks. Their deployment increases electricity demand, particularly during winter periods, while the thermal inertia of buildings and heating systems can allow consumption to be shifted or temporarily reduced. JRC estimates that heat pumps could account for around 5% of annual EU electricity demand on average, rising to as much as 11% during winter months, illustrating both their potential impact on network loading and the relevance of flexible operation [16].

Elia's Current Commitments scenario assumes approximately 1.1 million heat pumps in Belgium in 2030 [12]. However, the resulting flexibility is relatively modest under Elia's central assumptions: by the end of 2036, heat pumps provide on average around 7 MW upward and 6 MW downward fast flexibility, although their maximum contribution can approach 100 MW. A higher-flexibility sensitivity produces materially larger values of the maximum of about 450 MW for upward flexibility, demonstrating that the usable contribution is highly dependent on consumer participation and control assumptions.

The Netherlands provides a larger modelled system-level value: TNO assumes approximately 0.205 GWe of heat-pump flexibility from households in CA2030 scenario [15]. As with the EV figure, this is primarily an exogenous modelling parameter rather than a forecast of DSO-procured flexibility.

Thermal flexibility is not limited to heat pumps. RTE's French 2030 trajectory maintains approximately 3.3 GW of domestic hot-water consumption away from 19:00 and increases consumption shifted towards 14:00 from around 1.5 GW currently to approximately 5 GW. For the tertiary sector, RTE targets more than 2.5 GW of shifted electricity demand by 2030 [13].

Taken together, the evidence indicates that heat pumps and other thermally flexible loads can provide a meaningful source of flexibility, but their contribution is highly dependent on operating conditions and control assumptions. Outdoor temperature, building insulation and thermal inertia, thermal storage, heating system characteristics and occupant comfort requirements all influence how much demand can be shifted and for how long. Load shifting may also lead to rebound demand as indoor temperatures are restored following a flexibility event. For distribution networks, heat related flexibility should therefore be regarded as a potentially valuable but time- and weather-dependent resource rather than as a fixed amount of available capacity [16].

Stationary batteries

Stationary batteries provide a highly controllable source of flexibility, as their charging and discharging can be actively managed within power, energy and state-of-charge constraints. This makes them

particularly suitable for short-duration applications such as reducing demand peaks, absorbing surplus renewable generation and managing network congestion [17].

Belgium illustrates the expected scale of distributed battery deployment. Elia assumes around 1.1 GW of small-scale and residential battery capacity in 2030, rising to around 1.4 GW in 2035. Around 85% of this battery capacity is assumed to respond flexibly to market prices by 2030, increasing to almost the entire capacity by 2035 [12]. Under Elia's central scenario, these batteries provide on average approximately 430 MW of upward and 496 MW of downward fast flexibility by 2036. This shows that even where a large share of battery capacity is assumed to be flexible, the amount contributing at a particular time can be lower than the total capacity.

For Great Britain, the Clean Flexibility Roadmap foresees 23–27 GW of grid-scale battery capacity by 2030, while NESO's FES Holistic Transition scenario indicates 23.2 GW [14]. Grid-scale batteries may be connected to either transmission or distribution networks and should therefore not be interpreted as transmission-side resources only. However, these national installed-capacity figures do not indicate how much battery flexibility would be available to address specific DSO constraints. More directly relevant to distribution networks, modelling undertaken by Regen for the National Infrastructure Commission estimates that 7.4–11.5 GW of storage could be distribution-connected by 2030 [18]. This represents installed storage capacity rather than flexibility necessarily available to address DSO constraints, and includes distribution connected storage more broadly rather than residential batteries alone. For comparison, around 0.4 GW of behind-the-meter battery capacity in homes and buildings was operational in Great Britain in 2024 [19].

Stationary batteries can provide a substantial and highly controllable source of flexibility for distribution networks. Their main limitation is not responsiveness, but the amount of energy that can be sustained over time, which depends on battery energy capacity and state of charge. Batteries are therefore particularly well suited to short-duration and localised constraints, while their ability to address longer or recurrent constraints depends on sufficient energy capacity and continued availability.

Flemish example of aggregated residential and small-commercial flexibility

While the preceding examples consider individual asset types, their combined contribution can also be substantial. A VITO study commissioned by the Flemish Energy and Climate Agency (VEKA) estimates that low-voltage households and small professional customers in Flanders could provide around 1.31 GW of upward and 3.38 GW of downward flexibility under its average flexibility scenario on a representative median day in 2035 [20]. Availability varies over the day, from approximately 0.97–1.60 GW upward and 2.22–4.22 GW downward, with residential batteries, EVs and PV curtailment among the main contributors. Heat-pump flexibility is relatively limited on the representative median day but becomes substantially more important under winter conditions. These values represent aggregated potential across Flanders rather than flexibility necessarily available at a specific DSO constraint.

Accessibility of flexibility across customer segments

The flexibility potential identified in the preceding subsections does not necessarily translate into flexibility that is readily accessible to DSOs. Practical accessibility depends not only on the technical characteristics of the underlying resources, but also on the customer segment in which they are located and the arrangements through which they can be mobilised. For residential and small-commercial

customers, flexibility is typically distributed across large numbers of comparatively small assets, including EVs, heat pumps, behind-the-meter batteries, rooftop PV and other controllable loads. Mobilising these resources therefore depends on enabling conditions such as smart metering and data access, aggregation, automation, and appropriate retail and network price signals [9][10]. ACER and CEER note that, despite the growing availability of flexible consumer-side resources, a substantial share of residential flexibility remains untapped.

Industrial and larger commercial consumers differ in that flexibility can often be concentrated in fewer, higher-capacity loads or processes. They also currently appear to be more established providers of flexibility to European DSOs. The JRC DSO Observatory 2024 reports that 54% of surveyed DSOs use flexibility and that this is primarily sourced from industrial and commercial consumers and generation units, while the residential sector and emerging actors such as independent aggregators and virtual power plants remain significantly underutilised [8].

Overall, the evidence therefore suggests a distinction between the scale of flexibility potential and its present accessibility to DSOs. Residential flexibility could become a substantial distributed resource as EVs, heat pumps, batteries and PV become more widespread, but its fragmented nature means that aggregation, digital infrastructure and appropriate market and tariff arrangements are important for mobilisation. Industrial and commercial flexibility, by contrast, is already more commonly accessed by DSOs, although its availability remains dependent on the characteristics and operational constraints of individual processes.

4.3.2.1.4.1 DSO flexibility needs

While the preceding subsection considers the flexibility that distributed resources could provide, this subsection examines the network side need for flexibility. It reviews DSO network development plans and regulatory assessments that quantify network constraints that could potentially be managed through flexibility, expressed where available in terms of power, energy, location, timing and duration.

The terminology used by the underlying sources is not always consistent. Some DSOs refer to the amount of network overload that could be addressed through flexibility as “flexibility potential”. In this analysis, such values are treated as flexibility needs where they describe the response required to manage a network constraint, rather than the availability of flexible resources to provide that response. The estimates also differ in scope: some represent residual constraints after planned investments, while others identify constraints for which flexibility could avoid or defer reinforcement. The cases should therefore be interpreted individually rather than compared directly. Only methodological details that are important for interpreting the reported values are highlighted.

In The Netherlands, DSO Liander provides location-specific evidence on residual DSO flexibility needs in Appendix 10.10 of its Investeringsplan 2026 [21]. The appendix estimates the flexibility required per substation to address remaining network constraints after accounting for investments already included in the plan, expressed as annual overload volumes (MWh) for 2026, 2030 and 2035. These values represent a theoretical maximum: Liander does not assess whether the required flexibility is actually available or technically feasible, and values for individual installations cannot simply be summed because combined installations are also reported. For example, at the Tiel 10-2i installation, the annual consumption-side overload volume increases from 9,083 MWh in 2026 to 18,057 MWh in 2030 and 40,580 MWh in 2035. The appendix therefore provides useful evidence on the location and magnitude of residual network

needs that could potentially be addressed through flexibility, rather than an aggregated Dutch flexibility potential estimate.

Danish DSO N1 estimates the flexibility required to address projected network overloads that could otherwise require reinforcement. The requirement increases from 27 MW in 2025–2026 to 337 MW in 2030–2034. For 2030–2034, this comprises 81 MW at 30–60 kV, 238 MW at 10–20 kV and 18 MW at 0.4 kV; corresponding energy requirements are reported as 40,563 MWh at 10–20 kV and 382 MWh at 0.4 kV, while N1 omits MWh estimates for the higher-voltage network because of uncertainty in converting the calculated power requirement into energy [22]. The figures therefore describe the scale of network constraints potentially manageable through flexibility, not the amount of flexible resources available in the N1 area. N1 excludes short or more severe overloads where reinforcement is considered more appropriate, illustrating that flexibility is assessed only for a subset of projected network constraints.

Another Danish DSO TREFOR EI-net estimates the amount of projected network overload that could potentially be managed through flexibility rather than reinforcement. For 2030–2034, it identifies approximately 22 MW and 17.7 GWh of such need, entirely associated with 60/10 kV transformer overloads [23]. The estimate is technology-neutral and could therefore be supplied by EVs, heat pumps, batteries, industrial loads or combinations of resources, provided they are located behind the relevant constraint and available when required. The estimate is only partial: TREFOR does not provide an equivalent quantified requirement for the meshed 60 kV network or for the 10 kV and 0.4 kV networks at the same level of detail. The 22 MW and 17.7 GWh should therefore be interpreted as an asset-specific flexibility requirement rather than the total need across the DSO area.

Slovenia provides an aggregated national estimate of DSO flexibility needs. ELES' Distribution System Development Plan 2025–2034 estimates that the need for flexibility services increases from approximately 20.7 MW in 2025 to 27.2 MW in 2030 [24]. The estimate primarily reflects congestion and voltage management needs and is reported as a single annual value for the distribution system rather than by location or voltage level. For congestion, ELES extrapolates an analysis undertaken for the Elektro Ljubljana network to the national distribution system, while voltage-related needs are estimated using information on restricted connections of generation. ACER and CEER consequently classify Slovenia as having quantified flexibility needs in terms of power, but note that the underlying analysis was generalised from a limited part of the system and that the Slovenian regulator requested methodological improvements [25].

Portugal provides particularly granular evidence on DSO flexibility needs. In the PDIRD-E 2024, E-REDES introduces a probabilistic planning approach under which conventional investments may be deferred where the existing network can meet demand for at least 95% of the time, with flexibility used to manage the remaining risk; if the required flexibility cannot be obtained from the market, the conventional investment is implemented [26]. The proposal identifies seven investment projects, including new HV/MV substations and network reinforcements with a combined value of around €29 million, for which flexibility could potentially avoid or defer investment [27]. Rather than providing an aggregated national flexibility requirement, E-REDES specifies needs separately by location, year, season, day type, service window, voltage range, required power, activation duration and probability. For example, one requirement associated with the planned Bragança substation in 2026 reaches 8.63 MW for a six-hour winter weekday evening window, with an annual activation probability of 0.68% [28]. This case illustrates particularly

clearly that a DSO flexibility need is location- and time-specific. The relevant question is not only how many MW are required, but where, when and for how long the response must be delivered.

Sweden provides an aggregated indication of growing DSO flexibility needs from the first generation of distribution network development plans. Energimarknadsinspektionen (Ei) reports that, for 122–127 DSOs whose values could be aggregated, representing around 60% of Swedish electricity customers, the combined requirement for flexibility services and other resources increases from 277–1,030 MW over 0–2 years, to 640–1,883 MW over 3–5 years and 1,387–2,523 MW over 6–10 years [29]. Three additional DSOs, representing almost 20% of Swedish customers, were excluded from this aggregation because they reported consumption- and production-side requirements separately; their reported requirements are substantial, particularly on the production side, reaching 2,462–2,572 MW over 0–2 years and 2,110–2,550 MW over 3–5 years, while on the consumption side requirements reach 821–1,092 MW over 3–5 years. Ei cautions that reporting practices vary considerably and that the figures cannot be treated as a complete national requirement or used to infer the relative importance of consumption- and production-side flexibility.

Taken together, the cases show that DSO flexibility needs are highly dependent on the location and characteristics of individual network constraints. Some assessments provide aggregated power or energy requirements, while others specify needs by location, season, service window or duration. Several cases also indicate that these requirements are expected to increase as electrification and distributed generation place greater pressure on distribution networks.

Importantly, a quantified flexibility need does not demonstrate that sufficient flexibility is available to meet it. The aggregate resource potentials discussed in the preceding subsection can only contribute where suitable resources are located behind the relevant constraint and can provide the required response when needed. Whether flexibility can avoid or defer reinforcement therefore depends on the local availability, technical suitability, reliability and cost of the resources concerned. The following section considers this relationship within the broader context of distribution grid investment.

4.3.2.1.5 Distribution grid investment and the role of flexibility

The flexibility resources and DSO needs discussed above must be considered within the broader challenge of developing distribution networks to accommodate electrification and distributed generation. This section therefore reviews European and country-level evidence on the scale and drivers of distribution grid reinforcement, distinguishing reinforcement expenditure from broader investment in connections, asset renewal and modernisation. It also examines whether flexibility is already incorporated into these investment assessments and, where quantified, the extent to which greater flexibility could reduce or defer reinforcement. Differences in time horizons, scenarios and expenditure coverage mean that the estimates provide complementary perspectives rather than directly comparable measures.

European level

The Eurelectric/E.DSO/Monitor Deloitte study *Connecting the dots: Distribution grid investment to power the energy transition* [7] provides a particularly relevant near-term European benchmark. It estimates €375–425 billion of distribution grid investment across the EU27 and UK over 2020–2030. The total covers several investment drivers and should therefore not be interpreted as reinforcement

expenditure alone. The estimate was extrapolated from data provided by DSOs in ten countries representing around 70% of EU electricity demand.

More directly relevant to the present analysis, the study estimates €180–210 billion of investment associated with electrification and renewable integration over the same period. This comprises approximately €70–80 billion for electrification of buildings and industry, €25–35 billion for mobility electrification, and €85–95 billion for emission-free generation. The scenario assumes around 360 GW of new renewable capacity connected to distribution networks between 2017 and 2030, and 50-70 million battery electric vehicles and plug-in hybrid vehicles in 2030. The report explicitly states that meeting these developments requires new lines, reinforcement and additional transformer capacity.

An important feature of this estimate is that it is not a no-flexibility scenario. The study explicitly incorporates load-flexibility measures, including diversification and smart charging of EVs, to improve cost effectiveness. Substantial distribution investment remains necessary after these measures are assumed.

A more recent and longer-term perspective is provided by Eurelectric and EY's *Grids for Speed* [30]. While its estimates are not directly comparable with the Eurelectric 2021 study because of differences in geography, time horizon and methodology, it reinforces the conclusion that substantial distribution grid expansion will be required. The study estimates average investment of around €67 billion/year across the EU27 and Norway over 2025–2050, compared with approximately €36 billion/year currently. Of this, about 43% (€29 billion/year) is attributed to demand-driven reinforcement and 12% (€8 billion/year) to generation-driven reinforcement, implying roughly €37 billion/year of reinforcement associated with electrification and distributed generation.

The estimate reflects a strong electrification and decentralisation pathway, with around 237 million EVs and 251 million heat pumps by 2050, while approximately 70% of renewable generation and storage is assumed to connect to distribution grids. Reinforcement is required across all voltage levels, with around 44% of total investment at low voltage, 41% at medium voltage and 15% at high voltage. The study further estimates that Europe could require about twice as many distribution transformers and around 70% more grid length by 2050.

The analysis is based on country-specific representative LV, MV and HV networks and load-flow modelling of future demand and distributed generation. Important assumptions include allowing up to 1% annual renewable-energy curtailment and limiting local renewable export capacity to around twice local peak demand before curtailment, storage or alternative connection is considered. Several smart-grid measures are not included in the baseline reinforcement calculation. Eurelectric estimates that a combination of anticipatory investment, improved asset utilisation and flexibility could reduce total investment needs by around 18%, from €67 billion to approximately €55 billion/year, although this reduction should not be attributed to flexibility alone.

The study also highlights substantial variation in distribution grid investment needs between countries. Germany, France and Italy together account for approximately 50% of the estimated EU27+Norway investment requirement, with average annual distribution grid investment of approximately €17.7 billion in Germany, €10.1 billion in Italy and €5.4 billion in France. The Netherlands is estimated at €4.8 billion/year, Spain at €4.3 billion/year and Denmark at €2.0 billion/year. The composition also differs: Germany, Italy and Denmark have particularly high shares of demand-driven reinforcement, whereas replacement and renewal play a larger role in countries such as France and Norway. Eurelectric stresses

that these differences reflect national starting conditions, population density, expected peak-demand growth and the pace and composition of the energy transition.

Country level

In Belgium, Flemish DSO Fluvius' approved *Investeringsplan 2026–2035* [31] retains an additional €4 billion “no-regret” investment programme for 2023–2032 to prepare the distribution grid for electrification. Mobility electrification is identified as the main near-term driver of increasing peak demand, with heating electrification becoming increasingly important subsequently. At medium voltage, approximately 15% of distribution cables, equivalent to around 7,500 km, are expected to require reinforcement or renewal over the plan horizon. The low-voltage and distribution-transformer challenge is similarly substantial. Under Fluvius' central 2035 scenario, approximately 18,000 distribution substations are forecast to experience congestion, corresponding to around 28% of the total stock, or almost one in three. Of the €4 billion transition-related programme, approximately €2.8 billion is allocated to low-voltage networks and distribution substations and €1.2 billion to medium voltage. Importantly, Fluvius does not incorporate the effects of mitigating measures or changes in customer behaviour induced by market mechanisms in its investment requirements up to 2032. If such measures prove effective, investment requirements after 2032 could be reduced.

In The Netherlands, DSO Liander's final *Investeringsplan 2026 Elektriciteit en Gas* [21] provides particularly explicit physical evidence of the scale of expected distribution grid reinforcement. Depending on the scenario, Liander expects 150–160 of its approximately 180 substations to become overloaded by 2035. It also expects bottlenecks in approximately 25–40% of its low-voltage networks, particularly in older neighbourhood networks where EV charging and heat pumps are deployed at scale. Liander expects to invest approximately €5.9 billion in its electricity network during 2026–2028 to address identified constraints and maintain the network. The associated programme includes around 6,900 km of medium-voltage cable, 3,500 km of low-voltage cable and 6,300 new medium-voltage substations. Over the period to 2035, Liander plans approximately 37,000 km of new cable and the construction or reinforcement of almost 25,000 medium-voltage substations, as well as 57 new 150/110 kV and 34 new 50 kV substations, alongside expansion of 61 large and 46 smaller substations. The Liander case is also relevant to the flexibility assessment because EVs and heat pumps simultaneously contribute to projected low-voltage loading and offer potentially controllable demand. Liander therefore emphasises both network expansion and more flexible use of existing capacity, including grid-aware charging and flexible contracts. The scale of the planned physical expansion nevertheless indicates that flexibility is considered a complement to, rather than a replacement for, substantial grid reinforcement.

In Great Britain, the National Infrastructure Commission (NIC) study *Electricity distribution networks: Creating capacity for the future* [18] estimates that approximately £37–50 billion of additional distribution network investment could be required between 2024 and 2050 to accommodate growing electricity demand and generation. This is load-related expenditure in addition to business-as-usual investment, such as replacement of end-of-life assets, and represents at least a doubling of current annual allowances for load-related investment. The underlying scenarios explore different net-zero-compatible uptake pathways for low-carbon technologies and different levels of flexibility from EVs, heat pumps and batteries; around 60–70% of the modelled investment is projected to occur on the low-voltage network. Of particular relevance to the present analysis, the NIC finds that moving from lower- to higher-flexibility scenarios could reduce cumulative distribution network investment by around 15%, corresponding to

approximately £6.7–7.9 billion of savings over 2024–2050. Higher flexibility also delays some investment, although substantial reinforcement remains necessary. Importantly, the study states that these savings arise primarily from widespread flexibility reducing national peak demand, rather than from flexibility targeted at individual local network constraints. The UK Government subsequently welcomed the 15% finding and agreed that flexibility has an important role in avoiding or deferring network reinforcement [32].

French DSO Enedis' 2023 preliminary *Network Development Plan* [33] assesses distribution grid development under substantial electrification and renewable deployment. Its baseline scenario assumes approximately 13 million registered electric vehicles by 2032, and more than 70 GW of renewable generation connected to the distribution network. This includes around 28 GW of onshore wind and 42 GW of solar capacity by 2032, with the renewable trajectory broadly aligned with France's multi-annual energy plan (PPE). Enedis expects total annual investment to increase from just over €4 billion to consistently above €5 billion in 2027 and 2032, corresponding to an increase of approximately 20%. This total covers several purposes, including connections, reinforcement, renewal and modernisation, and should therefore not be interpreted as reinforcement expenditure alone. Enedis expects reinforcement needs to increase with renewable deployment, EV charging and heat pumps, while smart EV charging and diversity between uses are assumed to moderate this growth. Nevertheless, the continued high investment trajectory indicates that such flexibility measures do not remove the need for substantial distribution network development.

For a Spanish case, Herding et al. (2024) provide a national-scale analytical estimate of distribution grid reinforcement requirements under a 2030 Spanish energy-transition scenario [34]. The model covers more than 8,000 mainland municipalities and represents LV, MV and HV distribution networks, geographically allocating future PV, wind, EVs and heat pumps. Reinforcement costs are differentiated across Spain's 47 peninsular provinces and four network types - urban, semi-urban, rural concentrated and rural dispersed - using unit costs derived from actual projects of a Spanish DSO. The study estimates approximately 44 GW of distribution network asset upgrades, corresponding to €2.627 billion of total reinforcement investment by 2030, or around €197 million/year on an annualised basis. These estimates cover reinforcement triggered by both distributed generation and increasing electricity demand. Importantly, the calculation excludes expenditure for digitalisation and replacement of end-of-life assets, while EV-related reinforcement considers private charging only and excludes public charging and commercial vehicle fleets. The results are highly sensitive to load coincidence and assumed available network capacity. EVs and heat pumps increase unconstrained peak demand by about 17.1 GW, while simultaneity factors of 0.40 at LV, 0.85 at MV and 0.95 at HV reduce the resulting reinforcement-driving requirements. Because available hosting capacity for new demand is not publicly known, the model conservatively assumes zero spare capacity for additional load; LV PV is treated similarly where hosting-capacity data are unavailable. Higher coincidence of EV and heat-pump demand substantially increases reinforcement costs, indicating the potential value of managed demand. However, flexibility is not explicitly modelled, so the results should be interpreted as scenario-based reinforcement requirements rather than committed DSO investments.

Taken together, the studies indicate substantial distribution grid investment needs, although their scale and composition vary across countries and scenarios. Flexibility can reduce or defer part of this investment, while significant reinforcement remains necessary to accommodate electrification and

distributed generation. The estimated effect of flexibility depends strongly on the flexibility already assumed in the planning baseline and on the type of network constraints assessed. A full assessment of the value of flexibility relative to reinforcement would therefore require both options to be evaluated on a consistent basis, including the costs of securing and operating flexibility rather than considering avoided investment alone.

4.3.2.2 Flexible connection agreements

Flexible Connection Agreements (FCAs) are increasingly used by system operators as an alternative to immediate network reinforcement, allowing new or additional demand and generation capacity to connect while accepting temporary restrictions on grid access (load and/or generation curtailment) during constrained network conditions. Although the contractual and technical design of FCAs differs across countries and DSOs, several initiatives have already progressed from pilot applications toward operational implementation. To identify best practices and assess the practical deployment of these mechanisms, selected FCA initiatives are compared using a common set of indicators.

4.3.2.2.1 General characteristics of FCAs

FCAs provide network access under conditions that allow the available import or export capacity to be restricted. Their spatial applicability can range from standardised products available across an entire network to arrangements tailored to a specific constrained area or individual connection point. Nevertheless, their use is generally driven by local network conditions rather than uniform network-wide deployment. Within the reviewed benchmark, FCAs are primarily directed at professional and medium- or high-capacity grid users whose operational behaviour can materially affect network loading. They may apply to both demand and generation and are not necessarily restricted to specific technologies.

Participation is generally voluntary, allowing grid users to choose between a conventional firm connection and flexible access. Once an FCA is accepted, however, its operating conditions become binding for the duration of the agreement. Under certain frameworks, flexible access may also be required for specific new connections, capacity extensions or connection requests in constrained areas. Contract duration depends on the intended function of the FCA. Temporary agreements facilitate earlier connection while reinforcement is underway or until congestion is resolved, whereas permanent agreements establish conditional access as a long-term alternative to firm network capacity.

The operational design of FCAs can be static or adaptive. Static arrangements apply predefined capacity limits during fixed contractual periods, providing greater predictability to the grid user. Adaptive arrangements adjust the permitted import or export capacity in response to forecasted or actual network conditions. The applicable restrictions may be communicated according to predefined schedules, day-ahead, several hours in advance or close to real time. Longer notice periods provide greater operational certainty, while shorter notice periods allow the system operator to respond more closely to changing network conditions. Contractual restrictions are predominantly activated automatically through network-control systems or autonomous responses by the connected installation.

Conditional capacity can be allocated individually to each connection or shared among multiple users in a constrained network area. Shared arrangements seek to improve network utilisation by exploiting differences in users' operating profiles and reducing unused reserved capacity. Although first-come-first-

served remains an important principle for processing connection requests, more coordinated allocation approaches are emerging that consider readiness, prioritisation or the efficient use of scarce capacity.

When congestion occurs, restrictions may be distributed using last-in-first-out, proportional, priority-based or optimisation-based rules. Agreements may also limit the duration or extent of restrictions to provide greater operational and investment certainty. Additional conditions, such as use-it-or-lose-it and use-it-or-sell-it provisions, can further support efficient network utilisation by preventing scarce capacity from remaining unused. Overall, FCA design reflects a balance between maximising the use of existing network capacity, maintaining network security and providing sufficient predictability to connected grid users.

4.3.2.2.2 Comparative Analysis of Selected European Cases

In this section, selected representative FCA initiatives are compared using a common set of indicators. The comparison considers the number of grid users, sites or contracts connected under flexible arrangements, the total capacity covered by these arrangements, the energy curtailed or restricted following activation, and the number of curtailment activations. In addition, the curtailment limitation, or level of firmness, is considered to reflect the extent to which network access is guaranteed and the operational restrictions accepted by connected users. Table 13 summarises the results of these indicators for the selected FCA initiatives. The results mainly refer to the 2025–2026 period and are based on publicly available information. However, data availability differs across initiatives. For example, in Belgium, both in Wallonia and Flanders, regulatory frameworks require system operators to collect and report information related to flexible connections, but detailed operational data are not yet publicly available.

The results listed in Table 13 show substantial differences in both the reported scale of FCA implementation and the availability of operational data across the selected initiatives. UKPN provides the most comprehensive information among the considered cases, reporting 78 flexible connection sites with a total capacity of 853 MW in 2025/26. The number of flexible connections increased significantly compared with the previous year, when 55 sites representing 458 MW were reported, indicating the growing role of flexible connections in facilitating grid access. UKPN also reports a high level of network availability for flexibly connected users through its curtailment-efficiency KPI of 98.6%, indicating only 1.4% curtailment. However, aggregate data on curtailed energy and the number of individual curtailment events are not provided in the annual report.

For Belgium, operational data remain considerably more limited. In Wallonia, ORES has applied flexible access for injections for several years, while the demand-side framework has only recently been introduced and is not yet fully operational. Consequently, no quantitative operational indicators are currently available for flexible demand connections. Historical reporting for flexible injection identified 13 modulation orders across two production sites, with a total modulation duration of 194 h 56 min. These historical figures do not provide a complete or current estimate of the total number or capacity of flexible injection connections. No quantitative operational indicators are currently publicly available for FCA. Similarly, Fluvius reports 18 signed Fall-Back Flex contracts in Flanders as of August 2026, but does not publish the corresponding contracted flexible capacity, realised curtailed energy or number of activations. This illustrates that, although both Belgian regulatory frameworks require information on flexible connections and modulation to be collected, detailed operational data are not yet systematically disclosed publicly.

Table 13: Comparison of selected FCA initiatives

Initiative	DSO	# Grid contracts	Flexible capacity	Curtailed energy	# Activations	Curtailment limitation
Flexible Connections (UK) [35]	UKPN	78 sites	853 MW	Not publicly reported	Not publicly reported	98.6% curtailment efficiency
CBC (Capaciteitsbeperkingscontracten) – injection (NL) [36]	Alliander	238	848.7 MW	3,402 MWh	757	Not publicly reported (fixed time window or announced before curtailment)
CBC (Capaciteitsbeperkingscontracten) – demand (NL) [36]	Alliander	243	499 MW	Not publicly reported	47	Not publicly reported
Flexible connections (BE-WAL) [37]	ORES	Not publicly reported	Not publicly reported	Not publicly reported	13 historical orders for injection	Restrictions of up to 50% of maximum demand, for max. 700 quarter-hours/year, with max. 300 consecutive quarter-hours
Fall-Back Flex (BE-VLG) [38]	Fluvius	18 signed contracts	Not publicly reported	Not publicly reported	Not publicly reported	Not publicly reported

The Netherlands provides comparatively detailed operational information for Capacity Restriction Contracts (CBCs). At the end of 2025, 238 active injection CBCs represented 848.7 MW of flexible capacity, while 243 demand CBCs represented an additional 499 MW. Injection-side CBCs were activated 757 times during 2025, resulting in 3,402 MWh of reduced injection. Demand-side contracts were activated 47 times, although the corresponding reduced energy was not reported. These figures demonstrate both a relatively large deployment of contractual flexibility and recurring operational use in the Netherlands. However, activation frequency cannot be directly compared with the other initiatives because equivalent activation data are generally unavailable.

Overall, the comparison shows that FCA-related arrangements are operational at a meaningful scale in some networks, while implementation and data availability remain more limited in others. At the same time, the heterogeneity of public reporting prevents a fully standardised assessment across the selected initiatives. Differences in reporting periods and in the use of sites, contracts, capacity, activation instructions, curtailed energy and firmness indicators should therefore be considered when interpreting the results. More harmonised public reporting would be required to compare the deployment, operational use and level of firmness of FCAs consistently.

4.3.3 Dispatch simulations methodology and hypotheses

4.3.3.1 Modelling the impact of FCA and grid reinforcement on hosting capacity

This study assesses the impact of FCA and distribution grid reinforcement on renewables hosting capacity, both independently and in combination, through a sensitivity analysis covering six scenarios. The basecase includes neither mechanism: the distribution-transmission line is undersized, so the distribution grid's own peak renewable production is partly curtailed by that line's capacity. The second scenario reinforces the grid without introducing FCA, so all renewable production can reach the transmission system; curtailment can still occur further upstream, however, if national demand and cross-border export capacity are themselves saturated. The remaining four scenarios introduce FCA, allowing new solar capacity to connect either under FCA constraints in the distribution grid or directly to the transmission grid. These four scenarios combine two distribution grid states (reinforced or not) with two CAPEX levels for the direct transmission connection.

4.3.3.1.1 Modelling methodology

Distribution-grid dynamics are not well captured when a study represents each country by a single node, as it is common practice for pan-European dispatch models. Indeed, such a modelling choice ignores any existing constraint that may exist between the distribution and the transmission layers. The modelling framework designed in this study therefore isolates distribution grid-based renewables (solar, onshore wind) as well as FCA solar capacities from the rest of the electricity assets. Thus, flow constraints between transmission and distribution are actually taken into account.

In the basecase, onshore wind and solar assets sit on a *distribution* node, separate from demand and thermal plants on the *transmission* node. The flow between them is limited so that only 75% of the distribution node's own peak renewable output is deliverable. The remaining share is curtailed. Grid reinforcement, where modelled, simply removes this constraint, the same line is instead sized to carry the peak output in full.

In the FCA scenarios, new solar capacity connected under a flexible connection agreement is modelled separately. It faces no network capacity limit when exporting to the transmission grid, but its export is interrupted 1.4% of the time, during the solar fleet's highest-output hours, mirroring the FCA performance documented for UKPN above (98.6% curtailment efficiency, i.e. 1.4% of output curtailed). A second, competing option lets new solar connect directly to the transmission node instead, at a higher cost that also covers the grid reinforcement this direct connection requires. FCA-connected solar is therefore always the cheaper of the two options, in exchange for accepting the FCA's own curtailment risk.

4.3.3.1.2 Hypotheses taken

Two grid states were tested: the basecase 75%-of-peak distribution line described above and full reinforcement (100% deliverable). Two CAPEX levels for the direct-to-transmission connection were also tested: EUR 32k/MW/year (high, based on the French S3REnR framework) and EUR 28k/MW/year (low, based on an Energy Economics Institute from the University of Köln (EWI) study on *Cost-efficiency in the electricity system*), both compared against a fixed EUR 26k/MW/year for the FCA-connected option (ENTSO-E TYNDP 2024 CAPEX only, no grid-reinforcement cost). Combining the two grid states with the two CAPEX levels gives the four scenarios that test FCA/direct-connection investment. The basecase and full reinforcement, each with no such investment, complete the six-scenario design.

Each country's combined new-capacity ceiling across both connection options is capped using the same ratio observed in the United Kingdom: around 850 MW of solar under FCA there, against ENTSO-E's TYNDP2024 NT2030 installed solar capacity, gives a ratio of approximately 0.02. This ratio is applied to every country that already has a solar fleet in the 2030 baseline; countries without one are not given a new-capacity option.

Table 14: Synthesis of the modelled grid hosting scenarios

	No grid reinforcement	With grid reinforcement
No new solar installation	Basecase	Grid reinforced case
Potential new solar under FCA + on transmission node	2 sensitivities: high and low grid connection CAPEX	2 sensitivities: high and low grid connection CAPEX

4.3.4 Simulation results and analyses

4.3.4.1 Systems costs, CO₂ emissions

Table 15 compares system costs and CO₂ emissions across all 6 scenarios, averaged across the 3 climatic years (investment costs for grid reinforcement or new PV are excluded from system costs).

Table 15: Impact of grid reinforcement and FCA on system costs and CO₂, averaged across 3 climatic years

Case		system costs (M€)	CO ₂ emissions (Mt)
basecase		66 110	141,14
Case		Δ system costs (M€)	Δ CO ₂ emissions (kt)
FCA, no reinforcement	Low CAPEX	-770	-1,67
	High capex	-740	-5,08
FCA, with reinforcement	Low CAPEX	-3 500	-1,62
	High CAPEX	-3 480	-5,04
With reinforcement, No new solar installation		-2 830	-3,58

Both system costs and CO₂ emissions fall in every scenario relative to the basecase and fall furthest when FCA and grid reinforcement are combined. Reinforcement alone delivers the largest single gain (-2.8 bn€/year, -3.6 Mt/year), larger than FCA alone at either CAPEX level (roughly -0.76 bn€/year and -1.7 Mt/year). Indeed, reinforcement removes the distribution bottleneck for the entire existing renewable fleet, not only for the new capacity FCA adds. Combining FCA with reinforcement is cheaper still (-3.50 bn€/year), showing that if FCA solutions are implemented as an initial measure, for example whilst awaiting network reinforcements, they will continue to play a complementary role once the upgrades are complete.

4.3.4.2 Curtailment

4.3.4.2.1 Effect of grid reinforcement alone

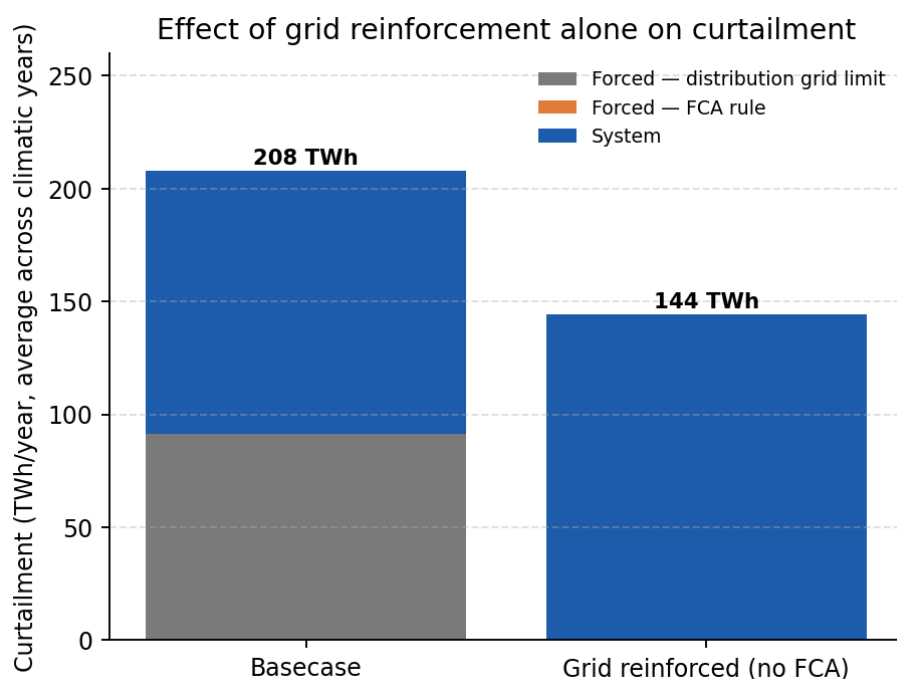


Figure 9 - EU-wide curtailment, basecase vs. grid-reinforced (no FCA either side), by cause, averaged across the 3 climatic years

As the distribution-transmission line is built as the actual physical bottleneck in the basecase, reinforcing it removes exactly the curtailment tied to that specific constraint. However, this does not represent the total reduction of curtailment as it falls from 208 TWh to 144 TWh/year, a 64 TWh reduction, not 91. The difference (~28 TWh/year) shows up instead as more system-level curtailment (116.5 up to 144.3 TWh/year). Physically, reinforcing the line lets much more renewable energy reach the transmission system than before. Most of that extra energy is genuinely useful, it displaces thermal generation, lowering system costs and CO₂ emissions as shown above. But some of it now runs into a different, downstream constraint that reinforcing this one line cannot fix. At hours when combined national supply already exceeds what demand and cross-border export capacity can absorb, the additional renewable output cannot be accommodated and is curtailed regardless. Economically, grid reinforcement shifts the binding constraint from a local issue, readily addressed through targeted investment, to a systemic one

that would require broader measures, such as additional interconnection, demand-side flexibility or storage, to be further mitigated. Reinforcement nonetheless yields a clear overall benefit, reducing total curtailment by 31%.

4.3.4.2.2 Effect of adding FCA, at each grid state

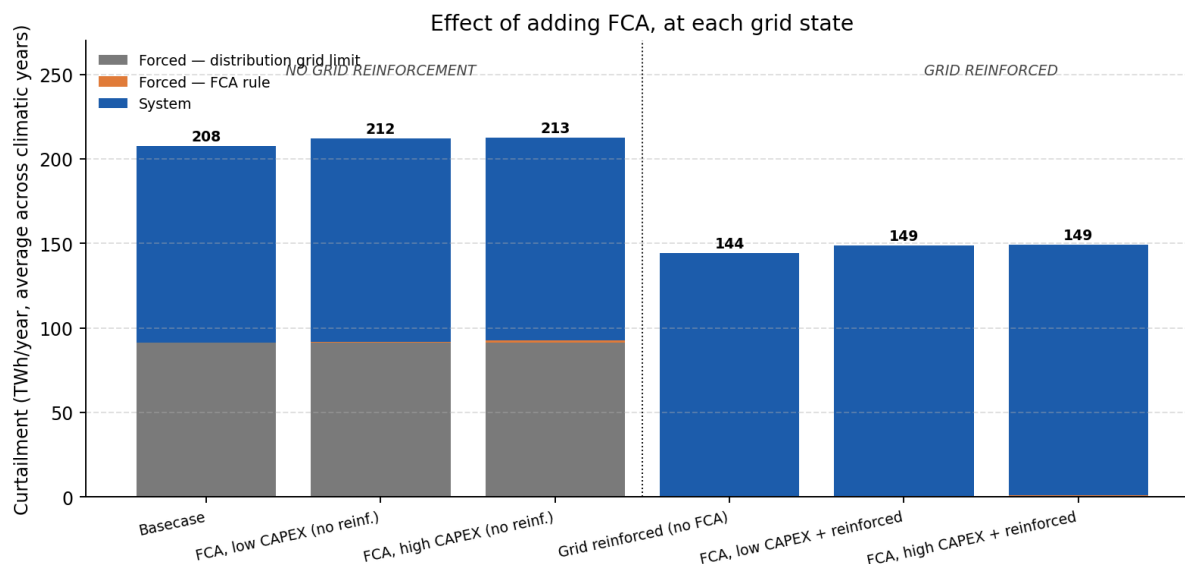


Figure 10 - EU-wide curtailment across all 6 scenarios, by cause, averaged across the 3 climatic years

Table 16 - Precise curtailment-by-cause figures

Scenario	Forced - FCA (TWh)	Forced - distribution (TWh)	System (TWh)	Total (TWh)
Basecase	0.00	91.18	116.53	207.70
Grid reinforced (no FCA)	0.00	0.00	144.26	144.26
FCA, low CAPEX (no reinforcement)	0.69	91.18	120.33	212.21
FCA, high CAPEX (no reinforcement)	1.26	91.18	120.28	212.71
FCA, low CAPEX + grid reinforced	0.69	0.00	148.12	148.81
FCA, high CAPEX + grid reinforced	1.19	0.00	148.03	149.22

Adding FCA at either grid state slightly increases total curtailment instead of reducing it, from 208 to 213 TWh per year without reinforcement and from 144 to 149 TWh per year with reinforcement. This is not a flaw in the mechanism. FCA brings a materially larger solar fleet onto the system, 16.7 GW more without reinforcement and 15.0 GW more with reinforcement, as detailed in the section on increased

solar installed capacity below, so a larger volume of solar output exists in the first place and some of it is curtailed. The increase breaks down into two distinct and much smaller effects. The first is a small, deliberate curtailment inherent to the FCA connection itself, between 0.69 and 1.26 TWh per year, representing the cost of the arrangement, under which solar accepts being switched off during its own highest-output hours in exchange for a cheaper and faster grid connection. The second is a small rise in system-level oversupply, around 4 TWh per year at each grid state, since the additional output from the new FCA-connected and transmission-connected solar occasionally coincides with hours when the wider system is already saturated. Despite this marginal increase in curtailed volume, FCA scenarios remain cheaper and less emissive than their respective no-FCA baseline, as shown above. FCA therefore does not reduce curtailment; it enables a materially larger renewable fleet at lower cost, and that fleet's net usable output still increases once its own curtailment is accounted for. Curtailment volume alone is consequently not the appropriate metric for evaluating FCA; usable production net of cost is the relevant one. The CAPEX level, low or high, has little effect on the total at a given grid state, consistent with the finding below that total new capacity is CAPEX-invariant and only its location changes.

4.3.4.3 Increased solar installed capacity

Across the four FCA scenarios, EU-wide new solar capacity depends on the state of the distribution grid, not on the CAPEX assumed for the direct-to-transmission connection. Without grid reinforcement, 16.7 GW of new solar capacity is installed. With the distribution grid reinforced, this falls to 15.0 GW, because grid reinforcement itself removes part of the capacity that FCA would otherwise have unlocked. In both cases, total capacity is identical whether the direct-to-transmission CAPEX is set to its low or high value. Only where that capacity connects, not how much of it is built, changes with CAPEX.

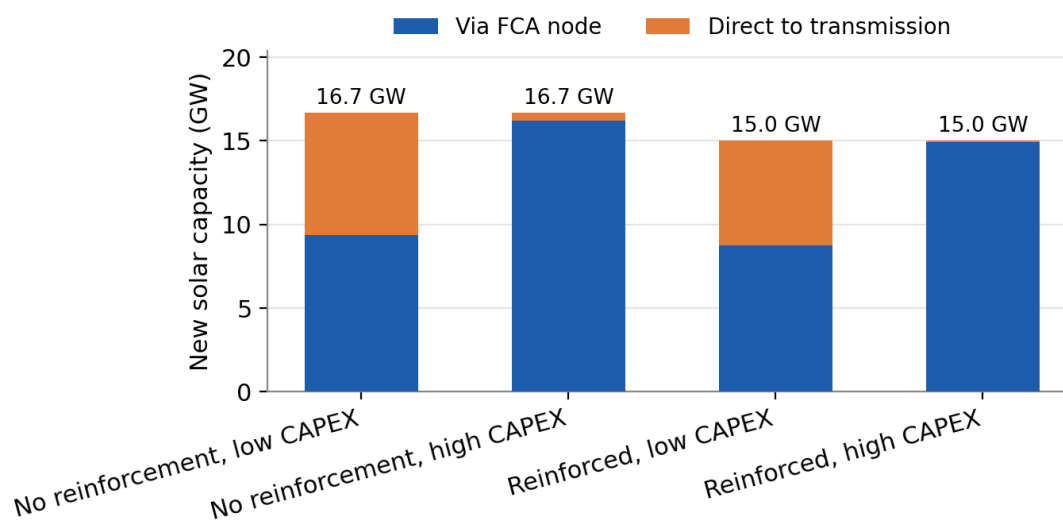


Figure 11 - EU-wide new solar capacity, by connection route, across all four FCA scenarios

The CAPEX assumption governs this choice of connection route. Under low CAPEX, new capacity splits fairly evenly between the FCA node and the direct-to-transmission option, roughly 9.3 GW against 7.3 GW without reinforcement. Under high CAPEX, the FCA node captures nearly all of it, 16.2 GW against 0.5 GW. This follows directly from how each option is priced. The FCA node is always the cheaper of the two, but

a higher CAPEX widens the price gap with the direct-to-transmission alternative, making the FCA's own curtailment risk, capped at 1.4% of the time, relatively less costly to accept.

New solar capacity by country and scenario (top 15)

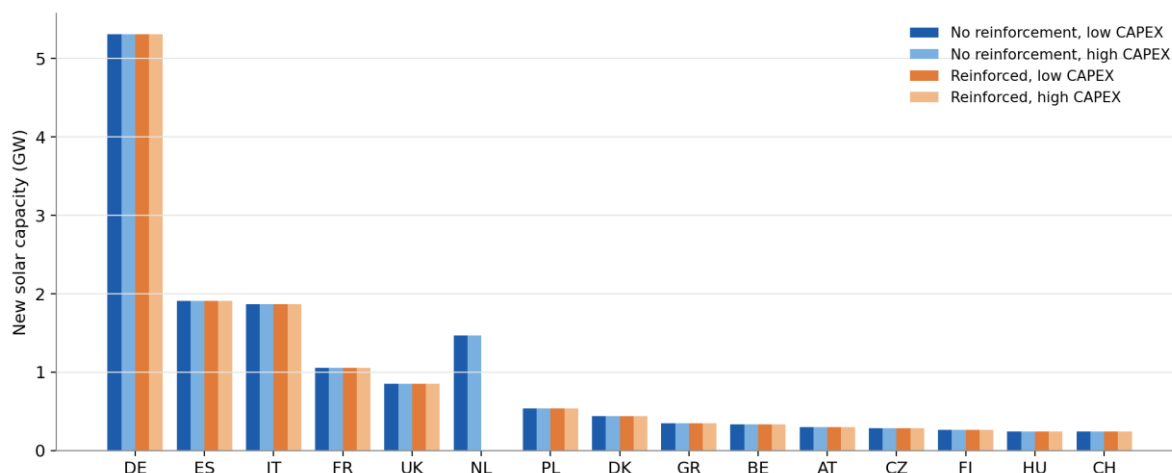


Figure 12 - New solar capacity by country, top 15, across all four FCA scenarios

Germany and Spain illustrate this most clearly. Both connect their new solar fleet through the FCA node in every one of the four scenarios, and together account for 7.22 GW of FCA-connected capacity, 5.31 GW in Germany and 1.91 GW in Spain, regardless of grid state or CAPEX. For most countries, the total new capacity installed barely moves across scenarios. The exceptions, where a country's total changes rather than only its connection route, are discussed in the next section.

4.3.4.4 Geographical focus

While EU-wide new capacity is largely stable across scenarios, individual countries behave very differently once grid reinforcement and CAPEX are considered together. Four distinct patterns emerge, summarised in Table 17.

The Netherlands and Portugal invest only when the distribution grid is not reinforced. The Netherlands installs its full 1.46 GW ceiling through the FCA node in both no-reinforcement scenarios, and nothing once the grid is reinforced. Portugal follows the same logic, but never reaches its ceiling even without reinforcement, installing 201 MW under low CAPEX and 207 MW under high CAPEX, only about half of its 403 MW ceiling. Portugal is the only country in the whole dataset that settles at a partial capacity rather than at zero or at its ceiling, consistent with its existing distribution-connected fleet already covering most of its own peak production once the grid is reinforced.

Greece, Cyprus and Albania switch connection route once the grid is reinforced, but only under high CAPEX. Without reinforcement, their new solar connects almost entirely direct to transmission. Once the grid is reinforced, the same countries move that capacity to the FCA node instead, because the distribution grid can now deliver their own peak production without the direct connection's added cost. Lithuania, Czechia and Austria show the identical switch, but under low CAPEX rather than high.

Table 17: Typology of country-level solar investment behaviour across the four FCA scenarios

Country / group	No reinf., low CAPEX	No reinf., high CAPEX	Reinforced, low CAPEX	Reinforced, high CAPEX	Behaviour
DE, ES (most countries)	FCA	FCA	FCA	FCA	Always FCA, capacity unaffected by grid state or CAPEX
NL, PT	Invest (FCA)	Invest (FCA)	Near 0	Near 0	Invest only when the grid is not reinforced
GR, CY, AL	Transmission	Transmission	Transmission	FCA	Switch to FCA once reinforced, under high CAPEX
LT, CZ, AT	Transmission	FCA	FCA	FCA	Switch to FCA once reinforced or if high CAPEX
UK, FR, PL, CH, IT, HU, FI	Transmission	FCA	Transmission	FCA	Same total capacity throughout, node follows CAPEX only
BE	Transmission	FCA	FCA	FCA	Transmission only in the single most favourable case
IE	0	0	0	0	Never invests, despite a non-zero ceiling
UKNI	0	0	0	0	Never invests, despite a non-zero ceiling

The United Kingdom, France, Poland, Switzerland, Italy, Hungary and Finland install the same total capacity in every scenario, so only the connection route responds to CAPEX. Under low CAPEX, these countries prefer the direct-to-transmission option, accepting the higher connection cost in exchange for capacity that is never curtailed by the FCA. Under high CAPEX, they switch to the FCA node instead, accepting the FCA's own curtailment risk in exchange for the cheaper connection.

Belgium is the single exception to this CAPEX-driven pattern. Its new solar connects direct to transmission only in the one scenario combining no reinforcement with low CAPEX. In every other scenario, including reinforced with low CAPEX, it connects through the FCA node instead, at an essentially constant total capacity of about 336 MW throughout.

Ireland never installs new solar capacity in any of the four scenarios, despite a 197 MW ceiling. Northern Ireland (UKNI) never installs new solar capacity either, despite having its own 15.23 MW ceiling and an existing distribution-connected solar fleet. Unlike Ireland's ceiling, however, UKNI's is small relative to the rest of the study, so the zero outcome has less influence on the EU-wide total. With these exceptions, and Portugal's partial outcome, every one of the 35 countries with a defined ceiling installs either nothing or at least 98% of its ceiling, in every scenario tested.

4.3.5 Conclusion on grid hosting capacities for system costs

If Flexible Connection Agreements, as piloted in the United Kingdom and tested by several TwinEU demonstrators, were available across the whole European distribution grid, up to 16.7 GW of additional solar capacity could connect without waiting for network reinforcement, at a system cost 0.76 bn€ per year lower than today and CO₂ emissions 1.7 Mt per year lower. This is a smaller gain than reinforcing the grid outright would deliver on its own, 2.8 bn€ and 3.6 Mt per year, because reinforcement relieves the existing renewable fleet as well as new capacity. However, FCAs are not an alternative to reinforcement but a complement to it: they allow new capacity to connect while reinforcement is being built and continue to add value once it is complete.

Combining both delivers the largest gain of all, 3.50 bn€ per year, confirming that FCA remains useful even on an already-reinforced grid. Both system costs and CO₂ emissions fall by a further 1% once FCA is added to a reinforced network. Some new solar capacity, chiefly in Germany and Spain, is cheaper to connect through a capped, occasionally curtailed FCA node than to build out further. This holds even where the local distribution constraint that first motivated FCA in the United Kingdom no longer exists.

Extrapolated to the pan-European scale, FCA is therefore best understood as a targeted tool rather than a uniform EU-wide policy. Its benefit depends on each country's own grid state and CAPEX conditions. Some countries would be more likely to adopt it fully regardless of circumstances, some would only benefit before their grid is reinforced, while others would gain nothing from it. This mirrors the unevenness already found for Forecast Accuracy, where Poland alone accounts for around 70% of the cross-country effect and the Netherlands sees a cost increase instead of a decrease. A pan-European rollout of FCA should therefore be planned and evaluated country by country, rather than assumed to deliver a single uniform benefit across the whole European system.

4.4 Dynamic Line Rating

4.4.1 Introduction

4.4.1.1 DLR - Principles and TwinEU Demonstration

Overhead line thermal ratings determine the maximum current (and therefore the maximum power flow) that a conductor can carry without exceeding safety limits related to sag, clearance and material ageing. Conventional grid planning and operation rely on Static Line Ratings (SLR) or, at best, seasonal ratings: fixed, conservative thermal limits derived from worst-case weather assumptions (typically high ambient temperature, low wind speed, and unfavourable wind direction relative to the conductor). While this approach guarantees a robust safety margin under virtually all conditions, it structurally under-exploits the transport capacity of the network, since real weather conditions are on average far more favourable to conductor cooling than the assumptions embedded in static ratings.

Dynamic Line Rating addresses this limitation by computing the real-time (or forecast) thermal capacity of a line as a function of the actual (or forecasted) local weather conditions along its route, primarily ambient temperature, wind speed and wind direction. In practice, DLR is expected to increase the effective transfer capability of critical corridors and improve the utilisation of existing transmission assets. It can also reduce renewable curtailment and defer costly grid reinforcement.

Within TwinEU, this potential is being tested concretely through two demonstration use cases. The Bulgarian (BG05: *"Increase of power flow on cross-border transmission lines"*) implements an AI-boosted DLR estimation method. This method derives line ratings from forecast climate parameters. It benchmarks these ratings against conventional seasonal limits on a selected set of cross-border lines. Its KPIs quantify the resulting increase in line rating and the improvement in effective line utilisation, or loading, compared to the seasonal-rating basecase. Furthermore, the Hungarian use case HU02, titled *"Enhanced flow-based capacity calculation for market co-optimization using DLR data"* feeds DLR-derived ampacity data directly into the flow-based capacity calculation used for cross-border market coupling. This aims to increase usable transmission capacity and to reduce congestion occurrences. In addition, assesses how frequently ratings can realistically be updated to reflect changing real-time grid conditions.

These two use cases are the demonstrators this DLR study relies on, as part of Task T9.5. Together, they cover two complementary layers. The first layer is the physical estimation of dynamic line ampacity. The second layer is its downstream integration into the market capacity calculation process. Thus, the aim of this study is to quantify the benefits these two layers would bring if extrapolated to the pan-European system.

4.4.1.2 DLR's transcription in FBMC-based modelling

The Hungarian use case shows that the value of DLR does not stop at the physical layer. It also depends on how this extra capacity is captured by the market. This is why this study represents cross-border exchanges through Flow-Based Market Coupling rather than through Net Transfer Capacity, as done in the other studies of this report. NTC modelling allocates cross-border capacity through a single simplified value per border. As explained in section 4.1.2.2, FBMC works differently. It computes capacity through the Remaining Available Margin of each critical network element. This margin is derived from the thermal limit of the line, minus the reference flow and a security margin called the Flow Reliability Margin. A change in line rating therefore propagates directly into the capacity offered to the market, element by element, rather than through one aggregated border value. This is why FBMC is the right framework to capture the true market value of DLR.

In this study, DLR is represented through a reduction of the security margin applied to the thermal limit of each critical network element and thus an improvement of the RAM. Today this margin covers the uncertainty embedded in static or seasonal ratings. A smaller margin means more room is left for cross-border exchanges on the same physical line. This approach lets us isolate the market and grid impact of better line state estimation, without needing to model the full weather-to-ampacity chain inside the market simulation itself.

4.4.2 Methodology and assumptions

The study compares one basecase run against five sensitivity runs. The basecase scenario uses the standard security margin applied today. Each sensitivity run reduces this margin by a fixed increment, from 2% up to 10%, in steps of 2 points. This lets us trace not only the overall gain from DLR, but also its marginal return as the margin correction increases. All runs share the same network topology and market data. They are simulated in FBMC over a single climatic year, unlike the NTC-based studies of this report which cover several. Results are compared on system costs, CO₂ emissions, curtailment, and welfare, as

well as on more granular indicators such as congestion hours, congestion rent, and price convergence between zones.

4.4.3 Simulation results and analyses

4.4.3.1 System costs, CO₂ emissions and curtailment

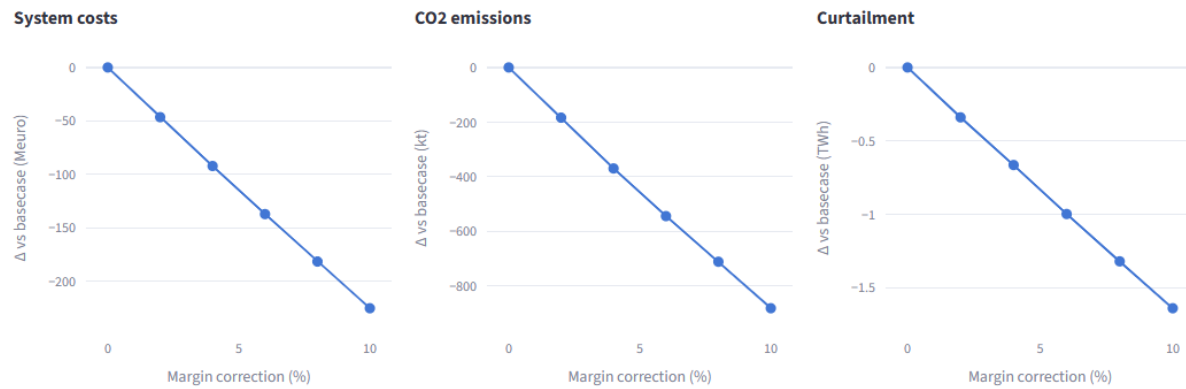


Figure 13 - Change in European system costs, CO₂ emissions and curtailment for different gains in RAM percentages (in M€)

Figure 13 shows the effect of relaxing flow-based margins from 0% (basecase) to 10%, in 2-point steps. All three indicators improve monotonically and close to linearly. System costs fall by €225.5 M/year at the 10% level, CO₂ emissions by 0.88 Mt/year, and curtailment by 1.64 TWh/year.

4.4.3.2 System costs by country

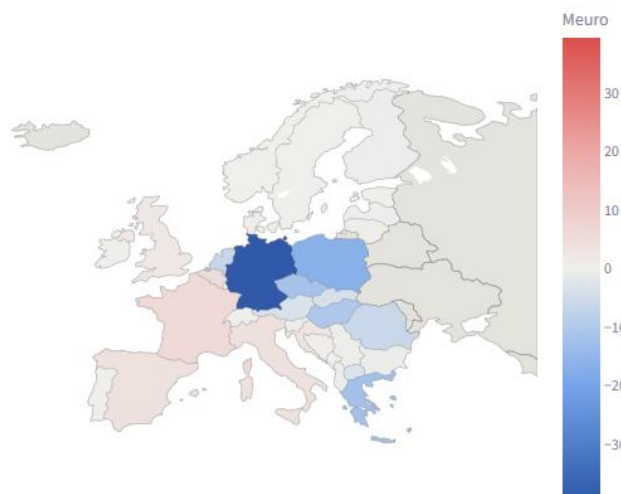


Figure 14 - Change in system costs by country at 2% margin correction (vs basecase)

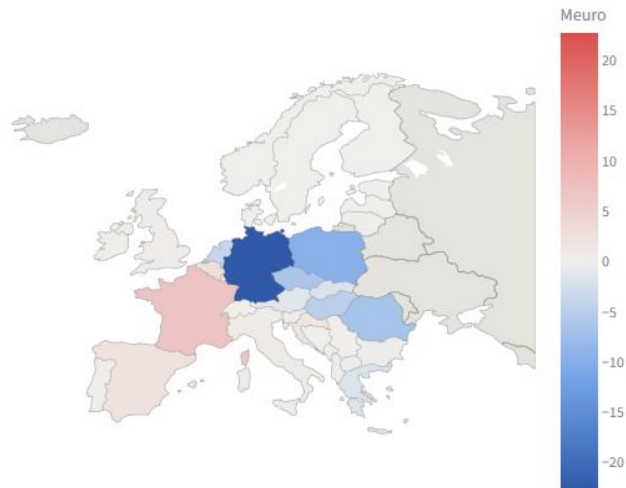


Figure 15 - Change in system costs by country at 4% margin correction (vs basecase)

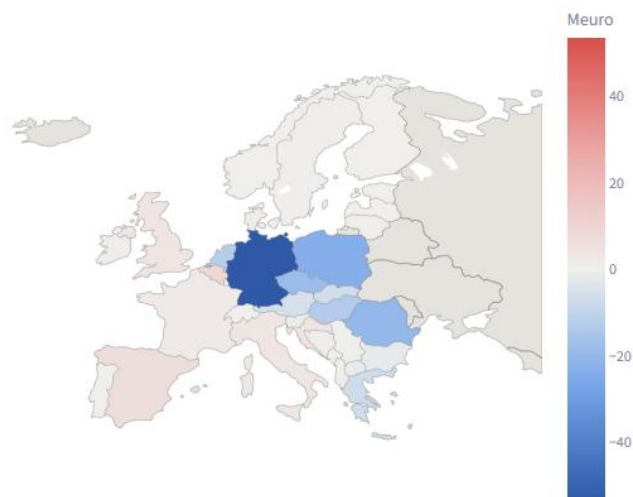


Figure 16 - Change in system costs by country at 6% margin correction (vs basecase)

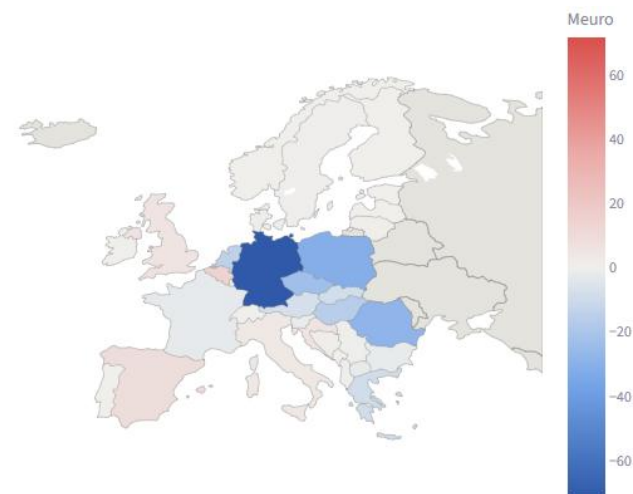


Figure 17 - Change in system costs by country at 8% margin correction (vs basecase)

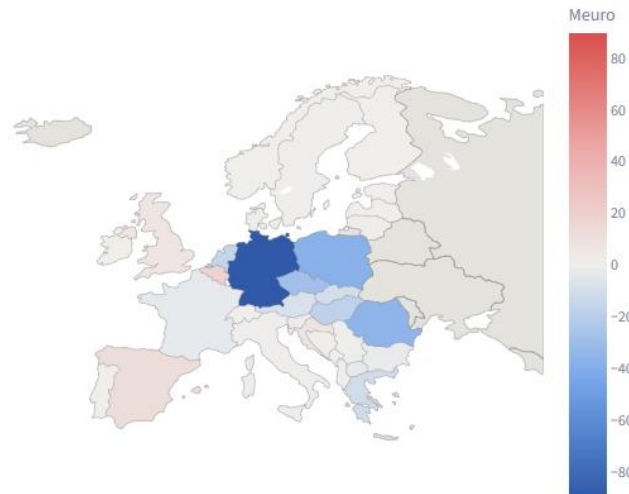


Figure 18 - Change in system costs by country at 10% margin correction (vs basecase)

Germany captures the largest share of the system cost reduction at every correction level, from 22.7 M€ at 2% correction to 89.5 M€ at 10%, close to 40% of the EU-wide gain on its own. 2% margin correction, Poland follows at 9.7 M€, then Romania (6.8 M€), Czechia (6.4 M€) and Hungary (5.0 M€). Together with Germany, these five countries already account for the bulk of the total effect at this level, and seven countries out of 35 are enough to explain 80% of the total absolute effect.

As the correction deepens, the same countries keep dominating and the gains scale up close to proportionally: Germany's saving reaches 89.5 M€ at 10% (about 40% of the 225.5 M€ EU-wide total), Poland's 38.1 M€, and Romania's 35.7 M€, while the number of countries needed for 80% of the effect only grows slightly, from 7 at 2% to 8 at 10%.

Not every country benefits. Belgium and Spain show a small but consistent cost increase that grows with the correction level, from about +2.5 M€ and +2.2 M€ at 2% to +18.0 M€ and +10.6 M€ at 10%. This is consistent with the price convergence results below: as DLR relieves the German-Austrian-Hungarian corridor, some previously favourable price differentials on secondary borders narrow or reverse, shifting a small amount of production cost onto neighbouring systems. France behaves differently again: its system costs rise slightly at low correction levels (+6.9 M€ at 2%) before turning into a small net decrease at 10% (-3.2 M€), a sign that its position in the network shifts from a secondary loser to a marginal winner as the correction deepens.

4.4.3.3 Concentration of welfare gains by country

At the 2% correction level, eight countries out of 35 already account for 80% of the total magnitude of welfare change across the system, the same concentration found for system costs and for the cross-border exchange maps: the benefit of DLR accrues to a limited set of countries rather than being spread evenly across Europe.

Germany (+11.6 M€) and Austria (+10.0 M€) capture the largest gains, consistent with their position on either side of the AT-DE and HU-AT corridors identified as the most heavily relieved constraints. France (+6.1 M€), the Netherlands (+5.3 M€), Poland (+4.5 M€) and Belgium (+3.9 M€) follow. Switzerland (-3.1 M€) and Luxembourg (-1.9 M€) are the only two countries with a materially negative welfare change: both

sit adjacent to the relieved German corridor without benefiting directly from the extra capacity and instead see some of their cross-border trading margin absorbed by better-connected neighbours.

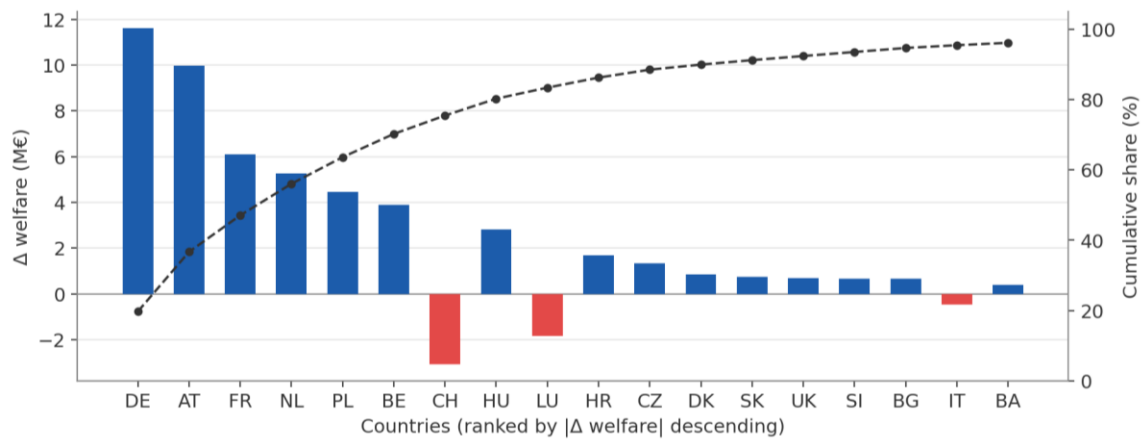


Figure 19 - Pareto analysis: concentration of welfare gains by country (2% margin correction vs basecase)

The same ranking holds at higher correction levels, with magnitudes growing close to proportionally: Germany's gain reaches +50.5 M€ and Austria's +47.7 M€ at 10% correction, while the total system-wide welfare gain grows from 46.6 M€ at 2% to 225.5 M€ at 10%.

4.4.3.4 Cross-border exchange map (Δ MW / % of line capacity)



Figure 20 - Cross-border exchange variation at 2% margin correction (vs basecase)



Figure 21 - Cross-border exchange variation at 10% margin correction (vs basecase)

The continental European electricity grid is not a uniform mesh. It is structured around a handful of historically dominant corridors. These stem partly from the geography of generation, such as Nordic and Alpine hydropower, French nuclear, and Central European thermal capacity. They also stem from the geopolitics of interconnection, with the continental synchronous area built around the Germany-Austria-Central Europe axis. Two elements were therefore expected before reading the map:

- The Austria-Hungary border is a well known bottleneck [39, 40] in ENTSO-E literature and in Core CCR studies. It is a natural crossing point between Western Europe and South-Eastern Europe, and it has historically concentrated significant loop flows. It is therefore no surprise that this is the line where the DLR gain is most spectacular, from about +4% at 2% correction to +24% at 10% correction. It is a natural candidate to be a binding CNEC in the flow-based domain.
- The Nordic and Baltic zones are already strongly interconnected and benefit from large hydro flexibility. They were expected to react less strongly, or even negatively, to a constraint relief elsewhere in Europe, since their exchanges are already optimised through other mechanisms, such as reservoir management and already highly correlated spot prices.

Three patterns confirm this reading. The DLR benefit is highly concentrated: most borders move by only ± 1 to 3 points, while a handful of lines around AT-HU and SI-AT capture most of the gain, confirming that DLR mainly benefits network elements that are already binding constraints. The dominant corridor also scales faster than the correction level itself, from about +4% at 2% to +24% at 10% (a factor of 6 for a factor of 5), suggesting a cumulative unlocking effect. Negative deltas in the Balkans and the North reflect a rebalancing rather than a loss, as flows that previously used these bypass routes shift back onto the relieved central corridor.

For a pan-European rollout, this means DLR's value follows the likelihood of a line being a binding constraint, not the length of grid equipped. Deployment should prioritise structurally congested corridors,

and its economic assessment should account for rebalancing effects on surrounding lines, not just the gain measured on the equipped line itself. This conclusion is consistent with the results of the Hungarian demonstrator "*Enhanced flow-based capacity calculation for market co-optimization using DLR data*". Its KPI HU02-KPI3 "*Hours with Beneficial DLR Activation*" found that only 0.75% of calculation periods in the day-ahead market and 0.98% in the second intraday auction saw DLR actually raise available capacity above the static rating. This confirms that the benefit is concentrated on a small subset of network constraints rather than spread evenly. KPI HU02-KPI2 "*Additional Transfer Capacity Enabled*" points the same way at demonstrator scale. It recorded a positive gain in every one of the 24 market time units tested (MTU), cumulated over CNEC-MTU combinations rather than simultaneous. This is again consistent with a benefit driven by a handful of binding constraints rather than a broad-based increase.

4.4.3.5 Congestion hours by line

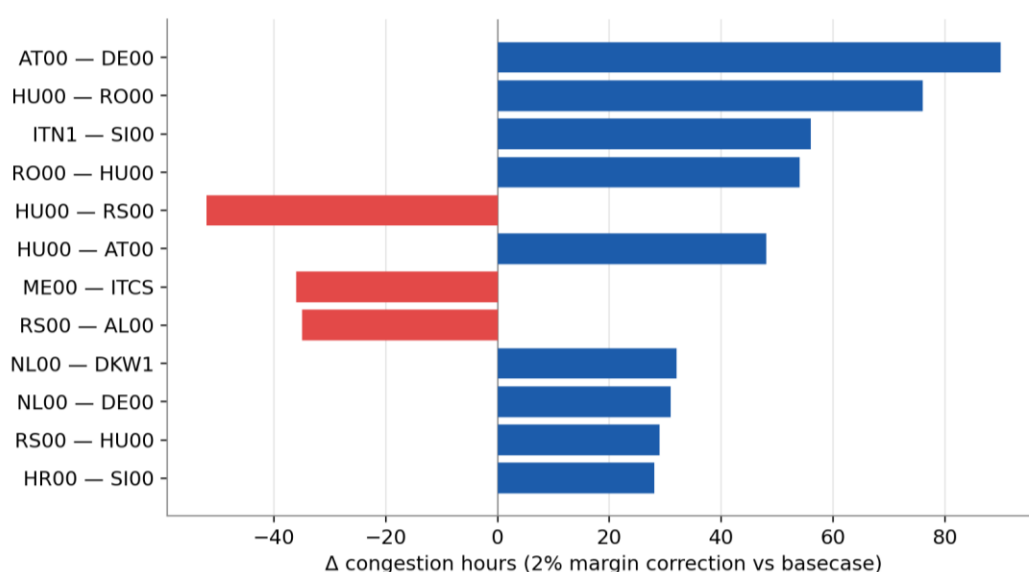


Figure 22 - Top 12 lines by |Δ congestion hours| (2% margin correction vs basecase)

Across the 214 lines with data in both scenarios, congestion hours move in both directions: 98 lines become congested more often, 89 less often, and 27 are unchanged. The net effect is a small system-wide increase of 320 congestion-hours, which may look counter-intuitive for a measure meant to relieve the grid, but it reflects a specific and economically sound mechanism rather than a degradation.

The AT-DE corridor illustrates this well. It is the single largest mover, both in absolute flow (+75 MW on average) and in congestion hours (+90 h), and it also captures the largest congestion rent gain of any line (+9.3 M€). Relaxing its margin does not just add slack: it makes the corridor more attractive to commercial flows, which fill the newly available headroom and keep the line binding, now at a higher and more valuable limit. The same logic applies to HU-AT (+48 h, +2.8 M€) and to the Hungary-Romania border (+54 h and +76 h on its two directions), consistent with the corridors already identified as structurally binding in the cross-border exchange analysis (Figure 21, Figure 22). Conversely, lines such as HU-RS (-52 h), ME-ITCS (-36 h) and RS-AL (-35 h) see fewer congested hours, as flows that previously used them as bypass routes shift back onto the relieved central corridor.

Table 18: Top 12 lines by $|\Delta$ congestion hours| (2% margin correction vs basecase)

Line	Capacity (MW)	Δ (MW)	Δ congestion hours	Δ congestion rent (M€)
AT — DE	7500	+75.0	+90	+9.29
HU — RO	1435	+0.0	+76	+0.14
ITN1 — SI	1153	+0.0	+56	+0.59
RO — HU	1617	+16.2	+54	+0.17
HU — RS	700	+0.0	-52	-0.20
HU — AT	800	+32.0	+48	+2.78
ME — ITCS	600	-6.0	-36	-0.18
RS — AL	250	-2.5	-35	+0.04
NL — DKW1	700	+0.0	+32	+0.13
NL — DE	5000	+50.0	+31	+1.45
RS — HU	600	+0.0	+29	+0.07
HR — SI	1500	+0.0	+28	+0.23

At system scale, the total congestion rent across all 214 lines falls slightly, by about 2.9 M€, even though individual corridors such as AT-DE and BE-NL gain 9.3 M€ and 8.6 M€ respectively. This is because lines such as DE-NL (-6.8 M€), CH-DE (-3.3 M€) and DE-FR (-2.6 M€) lose a comparable amount. Twenty-nine lines out of 214 are needed to explain 80% of this redistribution. Put together with the 46.6 M€ total welfare gain measured at the same 2% correction level, this indicates that the value created by DLR shows up mostly as savings on production costs for market participants, not as additional scarcity rent collected by TSOs on the relieved lines. Thus, DLR transforms congestion rent into system-wide welfare rather than simply growing it.

4.4.3.6 Price convergence between neighbouring zones

Table 19: Top 3 most-tightened and top 3 most-widened price spreads between neighbouring zones, basecase vs 10% margin correction

Border	Spread basecase (€/MWh)	Spread 10% (€/MWh)	Δ
CZ — DE	17.17	16.22	-0.95
DE — PL	11.86	11.06	-0.80
AT — CZ	4.32	3.75	-0.57
NL — NOS0	14.74	14.99	+0.25
DE — NOS0	16.76	17.01	+0.25
DE — SE04	15.98	16.23	+0.25

Averaged across all 112 borders, the mean price spread between neighbouring zones narrows only slightly, from €6.422/MWh to €6.394/MWh. A small aggregate move that masks more meaningful

individual changes like the Czech-German border which tightens by €0.95/MWh and Germany-Poland border by €0.80/MWh. A handful of Nordic-German/Dutch borders widen by €0.25/MWh.

Notably, the AT-HU corridor is the single line with the largest physical capacity and congestion relief response to the margin correction, as shown in section 4.4.3.4. It is not, however, among the most tightened borders on the price side. Its spread narrows only marginally from 7.25 €/MWh to 7.09 €/MWh, which corresponds to a change of just –0.16 €/MWh. Among the 112 borders studied, this change ranks only 20th. **This shows that the scale of a line's physical reinforcement and the scale of the price convergence it produces are two distinct dimensions.** Furthermore, in this case, the AT-HU spread was already comparatively tight before the correction, at 7.25 €/MWh, compared with 17.17 €/MWh for the CZ-DE border.

Market integration improves on the specific borders most exposed to margin correction without a strong system-wide convergence signal.

4.4.3.7 Storage-Network substitution (DLR and storage as competing or complementary flexibility levers)

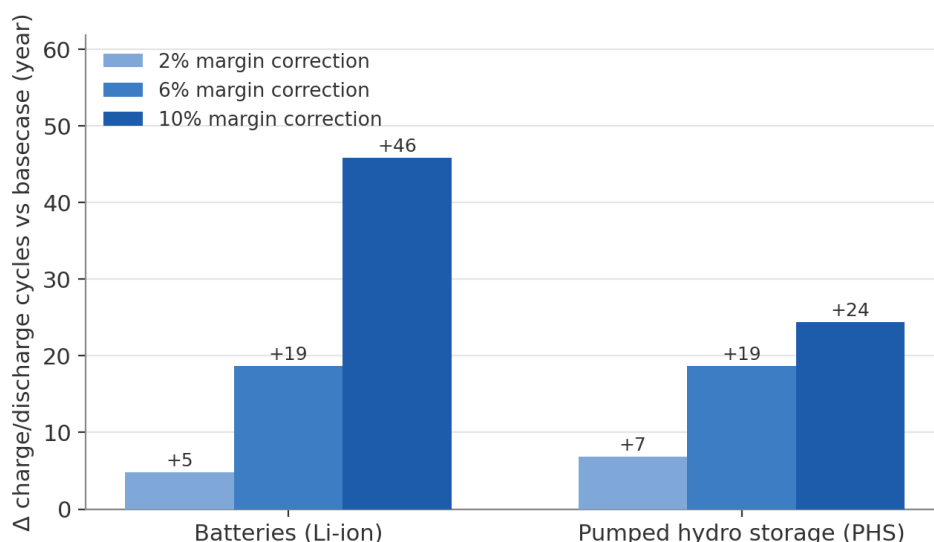


Figure 23 - Storage cycling by technology, change vs basecase at 2%, 6% and 10% margin correction

Both short-duration flexibility technologies cycle slightly more as the margin correction deepens, never less. Li-ion batteries cycle 5 more times per year than the basecase at 2% correction, 19 more at 6%, and 46 more at 10% (+0.4% overall). Pumped hydro storage follows the same pattern, with 7 more cycles at 2%, 19 more at 6%, and 24 more at 10% (+0.9% overall). The effect is small in absolute terms but monotonic and consistent across every level tested, and its direction is informative: relieving cross-border transmission constraints does not reduce the need for storage to manage local imbalances and price volatility. If anything, the additional cross-border trading opportunities unlocked by DLR create slightly more short-term price variation for storage to arbitrage.

The average daily price spread per node rises with the correction level, from 45.52 €/MWh in the basecase to 45.59 €/MWh at 10% (+0.15%), and storage does capture it. Combined revenue from batteries

and pumped hydro storage rises in step, from 11,918 M€ in the basecase to 11,991 M€ at 10% (+73 M€ equivalent to +0.6%), with both technologies moving in the same direction at every level tested.

Table 20: Storage revenue by margin correction level

Level	Battery revenue (M€)	PHS revenue (M€)	Total storage revenue (M€)
Basecase	3,623	8,295	11,918
2%	3,627	8,299	11,926
6%	3,634	8,335	11,969
10%	3,643	8,348	11,991

At the scale tested in this study, DLR and short-duration storage behave as mild complements rather than substitutes, and a pan-European DLR rollout should not be expected to materially reduce the flexibility capacity needed from batteries or pumped hydro.

4.4.3.8 Marginal return by margin correction level (2/4/6/8/10%)

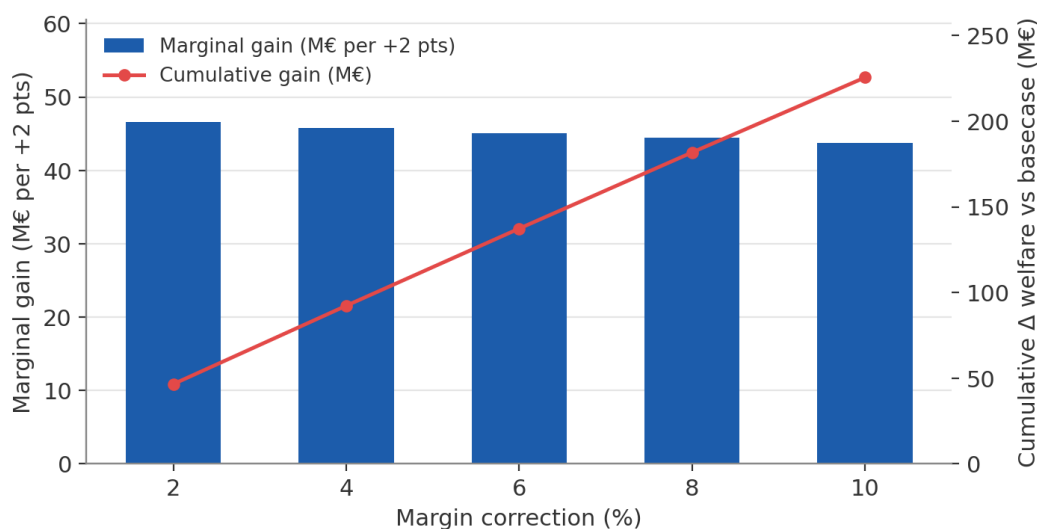


Figure 24 - Marginal and cumulative welfare gain by margin correction level

The welfare gain from margin correction is close to linear, but not exactly: the marginal return decreases slightly at each step, from 46.6 M€ for the first 2 points of correction to 43.7 M€ for the last 2 points, a decline of about 6% across the range tested (Table 21 and Figure 24). This system-wide diminishing return contrasts with the over-linear scaling found earlier on the single most binding corridor (HU-AT, Table 18), and the two observations are not contradictory. The corridor-level analysis looks at one CNEC in isolation, where relieving it further keeps unlocking flows already partly freed at the previous step, while the system-wide welfare figure aggregates this effect together with a growing number of secondary constraints that start to bind as the primary bottleneck is relieved and absorb part of the additional headroom. In practice, this means the highest-value increment of margin correction is captured early. A pan-European rollout should expect the largest euro-per-point return from the first steps of DLR

deployment on the most structurally congested corridors, with a gradually declining return as correction deepens further.

Table 21: Marginal and cumulative welfare gain by margin correction level

Margin correction (%)	Cumulative Δ welfare vs basecase (M€)	Marginal gain (M€ per +2 pts)
2	46.6	46.6
4	92.3	45.7
6	137.3	45.0
8	181.8	44.4
10	225.5	43.7

4.4.4 Conclusion on DLR for system costs

Dynamic Line Rating computes a transmission line's real-time thermal capacity from actual weather conditions instead of a fixed, conservative rating. This additional capacity relaxes the flow-based margin on lines that are actually binding constraints, allowing more cross-border trade to flow through them. Cheaper generation can then replace more expensive domestic production, and more renewable output can be exported instead of curtailed. If ANN-based or equivalent DLR methods were available across the whole European network, with margins safely corrected by 2%, this substitution alone would save the pan-European system on the order of 46.6 M€ per year. The additional room for renewable exports would also cut curtailment by about 0.34 TWh and CO₂ emissions by about 0.18 Mt, since less fossil generation is needed to compensate for otherwise-wasted renewable output. This benefit grows close to linearly with the depth of the correction achieved. Even a modest first step already delivers a proportional share of it across all three metrics.

This gain is not spread evenly across Europe, because DLR only creates value where a line is already a binding constraint. It concentrates on a small number of countries and corridors, chiefly Germany, Austria and the Austria-Hungary border. This corridor is structurally congested by loop flows in Central Europe. Relaxing its margin therefore unlocks disproportionately more previously-blocked trade than anywhere else on the network.

4.5 Grid Monitoring

4.5.1 Introduction

4.5.1.1 Principles and rationale

Transmission assets are taken out of service for two distinct reasons. Planned maintenance is scheduled in advance to inspect and service equipment. Forced outages are unplanned failures that occur at random. Conventional maintenance planning is largely time-based. Interventions are scheduled at fixed intervals regardless of the actual condition of the asset, which tends to produce maintenance windows that are longer, or more frequent, than strictly necessary in order to remain conservative.

Grid monitoring, in the form of continuous condition-based monitoring of lines and substations (temperature, partial discharge, vibration and other sensor data), lets a TSO replace this fixed schedule with interventions sized to the asset's actual state. In principle this shortens planned maintenance windows without compromising safety, since work is targeted at the specific condition detected rather than at a conservative worst case.

4.5.1.2 Monte-Carlo methodology

Forced outages are random by nature. They represent which line fails, when, and for how long varies from one realization of the future to another, independently of how many days are allocated to planned maintenance. A single simulation per maintenance-duration scenario would therefore conflate the effect of the policy being tested with the effect of whichever particular sequence of random outages happened to be drawn.

This study addresses this by running each maintenance-duration scenario ten times, each with an independent Monte-Carlo draw of forced-outage realizations, over three climatic years. This lets the analysis separate two things that a single run cannot: the mean effect of maintenance duration on the system, and the dispersion around that mean caused by the random outages themselves. As the results below show, this distinction turns out to matter a great deal. It is close to negligible for system costs, but it dominates the picture for security of supply.

4.5.2 Hypotheses taken

In this study, the benefit of grid monitoring technologies is therefore modelled through a single lever, a reduction in the number of planned maintenance days that are necessary to keep a similar amount of forced outages per year. A dedicated maintenance-scheduling module determines, for each line, the periods that minimise its impact on the system, such as periods of lower demand or lower network criticality. Every maintenance-duration scenario therefore uses its own optimised schedule, sized to the number of days being tested.

The study compares results across five scenarios, testing 4, 5, 7, 8 and 9 days of planned maintenance per transmission line per year. Unlike Dynamic Line Rating, no TwinEU demonstrator directly measures the maintenance-day reduction achievable from better grid monitoring. This representation of the pilots' benefit was chosen instead for its generality, its ability to extrapolate to the pan-European scale and because it is easy to understand without requiring a detailed model of any specific monitoring technology. The forced-outage process is deliberately left unchanged across scenarios. It is not itself a lever tested here but a source of statistical noise that the Monte-Carlo draws are designed to quantify alongside the maintenance-duration signal.

4.5.3 Simulation results and analyses

4.5.3.1 System costs, CO₂ emissions and curtailment

Figure 25 shows system costs for every combination of maintenance duration, climatic year and Monte-Carlo draw:

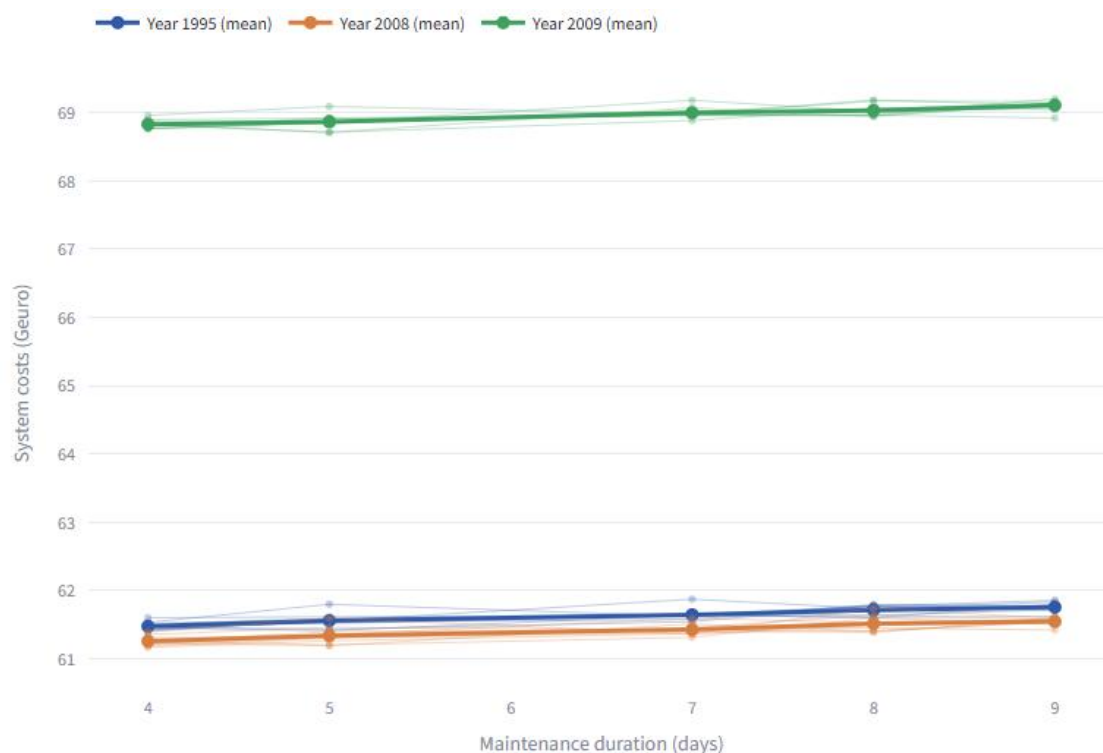


Figure 25 - System costs across the maintenance-duration sweep, by climatic year and Monte-Carlo draw

System costs depend far more on the weather conditions in a given year than on the number of maintenance days or the costs associated with outages. They increase monotonically and close to linearly with maintenance duration, in every one of the three climatic years, and the 10 draws of a given scenario/year sit close to their mean. Averaged across years, going from 5 to 4 days of maintenance saves 60 M€/year, going from 5 to 9 days costs an extra 220 M€/year (Table 22).

Table 22: Impact of scheduled maintenance duration on system costs, CO₂ emissions and curtailment, average across the 3 climatic years and 10 Monte-Carlo draws, with 5 days of maintenance as reference

Maintenance duration	Δ system costs (M€)	Δ CO ₂ emissions (kt)	Δ curtailment (GWh)
4 days	-60	-200	-600
5 days	0	0	0
7 days	+100	+300	+1,300
8 days	+170	+500	+1,800
9 days	+220	+900	+2,600

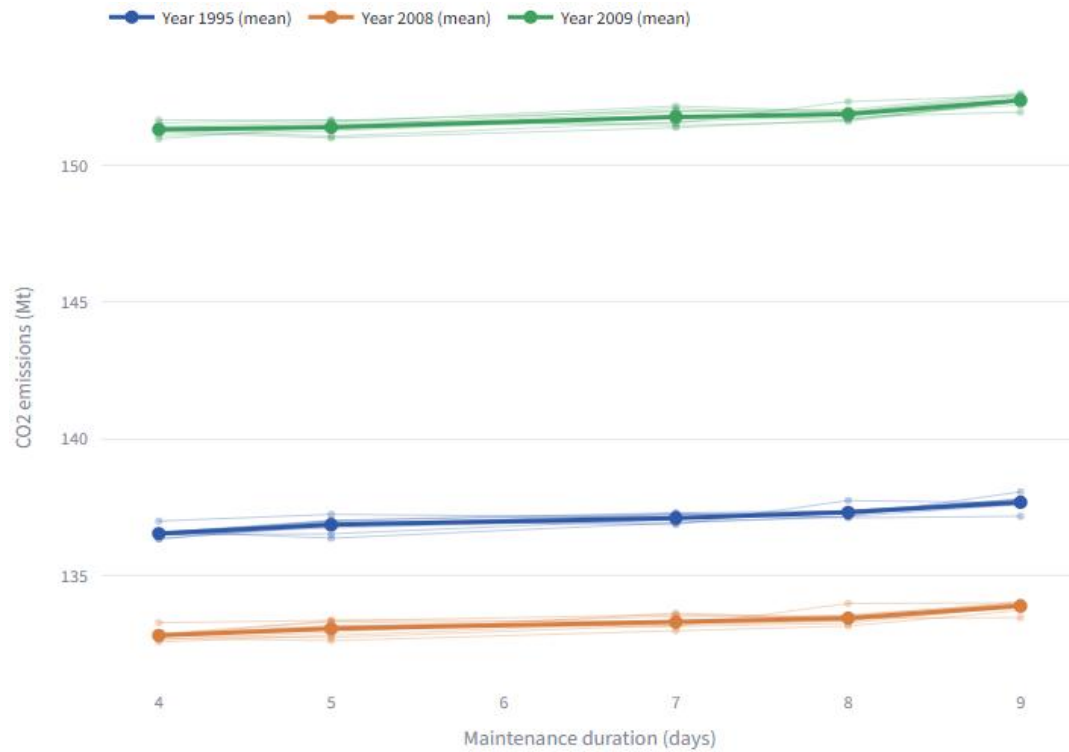


Figure 26 - CO₂ emissions across the maintenance-duration sweep, by climatic year and Monte-Carlo draw

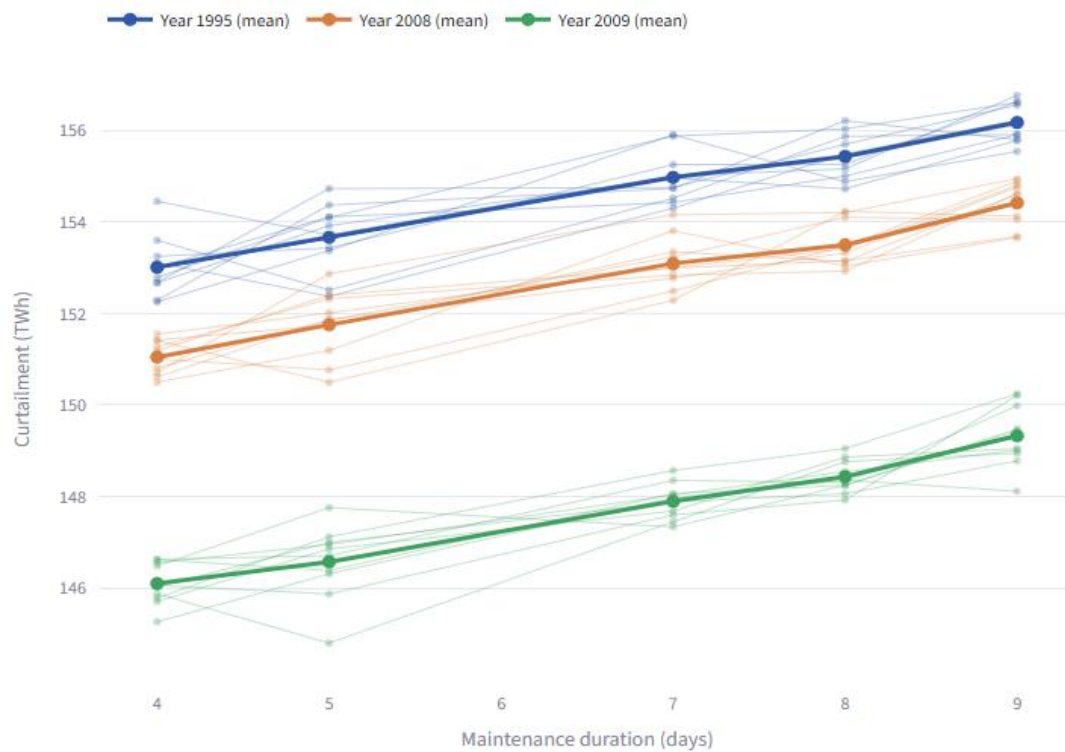


Figure 27 - Curtailment across the maintenance-duration sweep, by climatic year and Monte-Carlo draw

Figure 26 and Figure 27 show the same pattern for CO₂ emissions and curtailment than system costs. The impact of climatic years is predominant and both increase monotonically with maintenance duration, with a similarly tight spread between draws. Averaged across years, and compared with the 5-day maintenance scenario, CO₂ emissions fall by 0.2 Mt/year at 4 days and rise by 0.9 Mt/year at 9 days. Curtailment falls by 0.6 TWh/year at 4 days and rises by 2.6 TWh/year at 9 days. Longer maintenance windows take transmission capacity out of service for longer, which forces more redispatch toward higher-cost, higher-emission generation and leaves more renewable output unable to reach demand.

These results are summarised in Table 22 above.

4.5.3.2 Security of supply

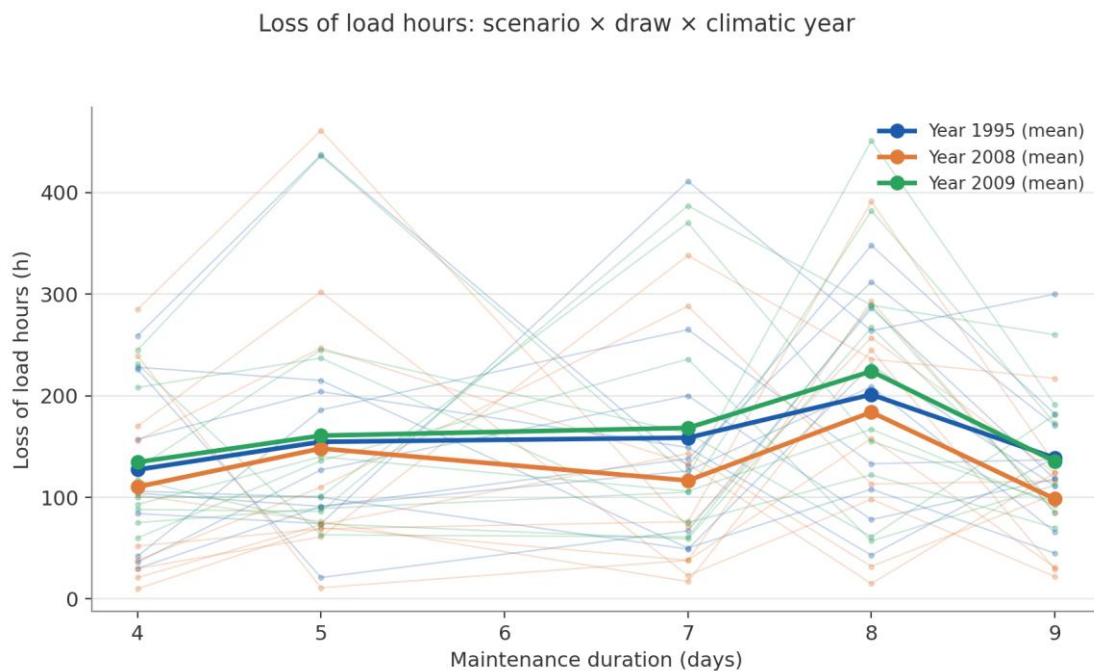


Figure 28 - Loss-of-load hours across the maintenance-duration sweep, by climatic year and Monte-Carlo draw

This Figure 28 on loss-of-load hours tells a very different story from the previous system-cost chart. The individual Monte-Carlo draws (thin lines) are scattered across a wide range at every maintenance duration, and the yearly means (thick lines) do not move monotonically with maintenance duration. Indeed, averaged across years, loss-of-load hours vary from 124h at 4 days, to 154h at 5 days, down to 148h at 7 days, up to a peak of 203h at 8 days, and back down to 124h at 9 days. The standard deviation across draws, 65 to 121 hours depending on the scenario, is comparable to or larger than the differences between scenarios themselves.

The same pattern holds for loss-of-load volume and cost:

Table 23: Security-of-supply indicators by maintenance scenario, mean $\pm$ standard deviation across the 3 climatic years and 10 Monte-Carlo draws

Maintenance duration	Loss-of-load hours (h)	Loss-of-load volume (TWh)	Loss-of-load cost (M€)
4 days	124 $\pm$ 82	33.9 $\pm$ 31.6	135.7 $\pm$ 126
5 days	154 $\pm$ 121	36.8 $\pm$ 31.9	147.1 $\pm$ 128
7 days	148 $\pm$ 114	39.1 $\pm$ 36.0	156.2 $\pm$ 144
8 days	203 $\pm$ 117	45.3 $\pm$ 32.1	181.1 $\pm$ 128
9 days	124 $\pm$ 65	32.3 $\pm$ 29.1	129.1 $\pm$ 117

This is not a data quality issue, it is the direct consequence of running 10 Monte-Carlo draws per scenario. **Security of supply is driven overwhelmingly by where and when the random forced outages occur, more than the 4-to-9-day range of planned maintenance duration tested here.** With the sample size used in this study, no robust monotonic trend can be extracted from the mean alone for these three indicators, in contrast to the low-noise relationship found for system costs, CO₂ emissions and curtailment.

4.5.3.3 Welfare by country

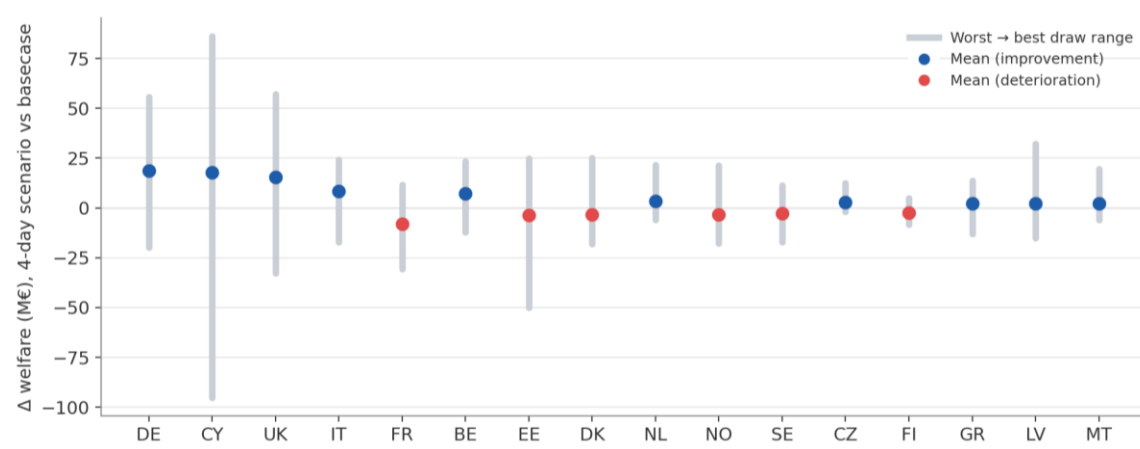


Figure 29 - Welfare by country, worst / mean / best Monte-Carlo draw (4 days vs 5 days of maintenance)

Averaged over draws, going from 5 to 4 days of maintenance redistributes welfare unevenly across countries. Germany (+18.6 M€), Cyprus (+17.8 M€), the United Kingdom (+15.3 M€) and Italy (+8.5 M€) gain the most on average, while countries like France can lose on average (-8.0 M€ for France) despite the EU-wide improvement.

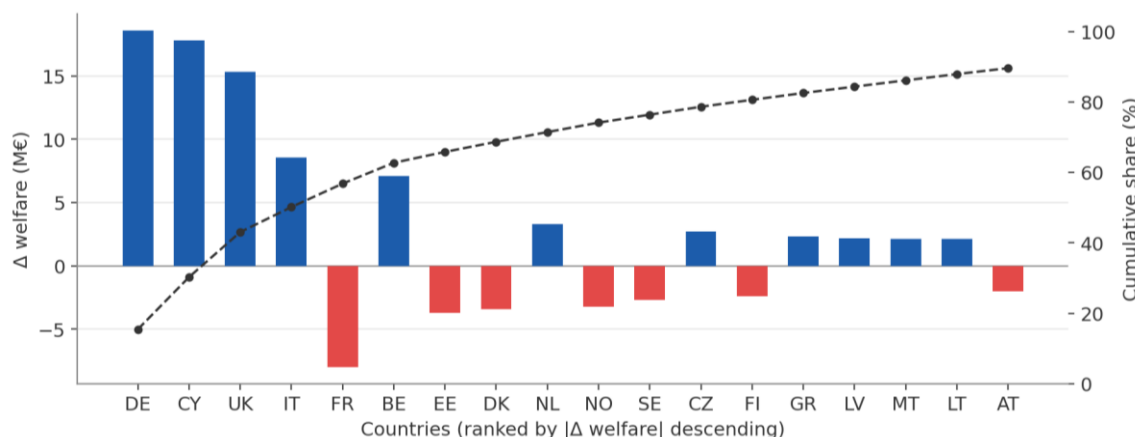


Figure 30 - Pareto analysis: concentration of welfare gains by country (4 days vs 5 days of maintenance)

Thirteen countries out of 35 are needed to explain 80% of the total effect magnitude, a wider concentration than found for Dynamic Line Rating, consistent with a sweep that acts on transmission availability system-wide rather than on a handful of specific corridors.

The worst-to-best range in Figure 29 echoes the security-of-supply finding above because for most countries the gap between their best and worst draw is far larger than their mean. Cyprus is the extreme case, ranging from -95.1 M€ in its worst draw to +86.1 M€ in its best, around a modest +17.8 M€ mean, a small, weakly interconnected system whose welfare is highly sensitive to exactly which lines are affected by a given draw. Germany and the United Kingdom show the same pattern at a smaller relative scale. A country's average outcome is therefore a much less complete description of its exposure to the maintenance-duration policy than the range of what a specific year's forced outages could do to it.

4.5.3.4 Congestion hours by line

Of the 234 transmission lines with data in both scenarios, 108 see fewer congestion hours under the 4-day scenario and 99 see more, with the remaining 27 unchanged. Summed across all lines, congestion hours rise slightly overall (+336h). As with Dynamic Line Rating, a system-wide average masks a much more concentrated reality at line level. The most relieved lines are Nordic and Baltic corridors (DKW1-SE03, -564h and NON1-NOM1 with -370h) and the GR-ITS1 interconnector (-323h), consistent with less time spent on planned outage freeing up capacity on lines that were already tightly used. The most affected lines in the other direction are concentrated on the interconnectors around the United Kingdom (BE-UK, +708h and DE-UK with +655h and NL-UK, +522h). As continental transmission capacity becomes more available for a larger share of the year, commercial flows reroute toward these corridors, which end up binding more often even though the change tested is, system-wide, an improvement. This mirrors the rebalancing effect already observed for Dynamic Line Rating, relieving one part of the network can concentrate additional stress on another part of it.

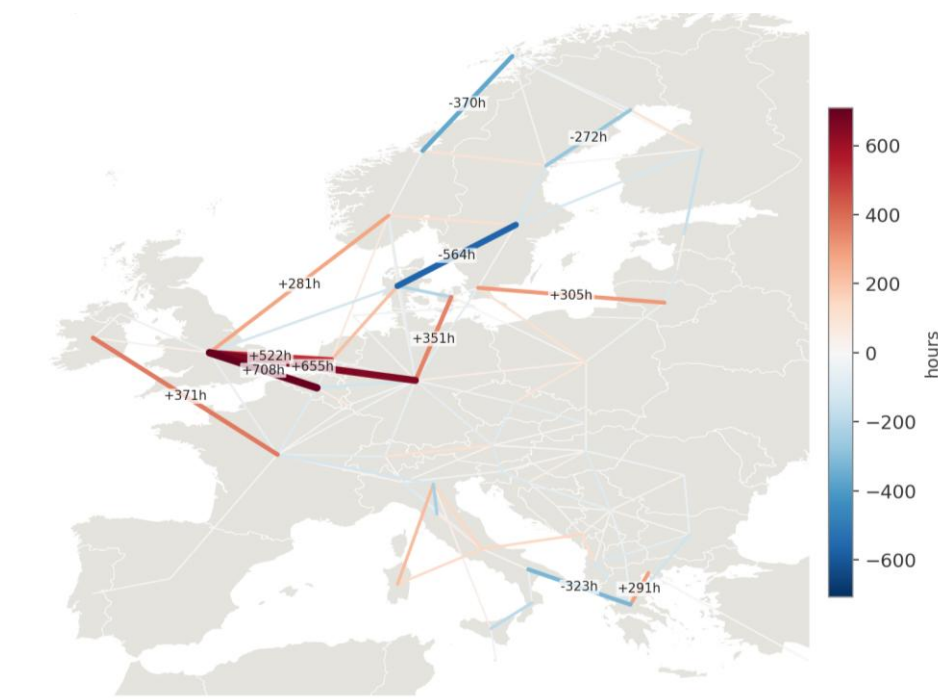


Figure 31 - Δ congestion hours by line (4 days vs 5 days of maintenance)

Table 24: Top 6 most-relieved and top 6 most-worsened lines by Δ congestion hours (4 days vs 5 days of maintenance)

Line	Δ congestion hours
DKW1 — SE03	-564
NON1 — NOM1	-370
GR — ITS1	-323
SE01 — SE02	-272
ITCN — ITCO	-228
DKW1 — DKE1	-213
LT — SE04	+305
DE — DKE1	+351
FR — IE	+371
NL — UK	+522
DE — UK	+655
BE — UK	+708

4.5.3.5 Marginal return per maintenance day avoided

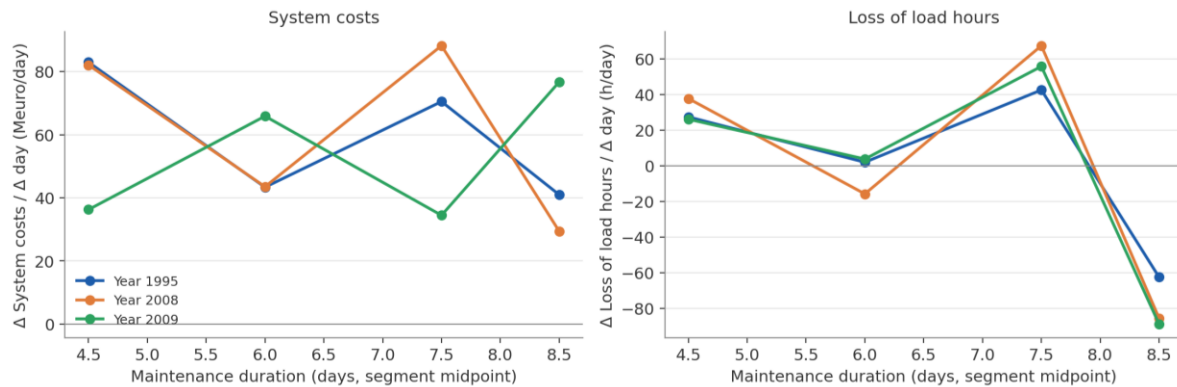


Figure 32 - Marginal return of one additional maintenance day on system costs, by climatic year

Figure 32 shows the marginal effect of one additional maintenance day, for system costs and loss-of-load hours, computed for each pair of consecutive durations in the sweep and for each climatic year. For system costs, the marginal return is positive in every one of the twelve segment-year combinations tested, from 29 to 88 M€ per day, with no clear preference for one segment of the 4 to 9 day range over another. For a same probability of outages, every additional day of planned maintenance makes the system more expensive, whichever segment or climatic year is considered.

For loss-of-load hours, the same computation changes sign between segments and between years within the same segment. This does not mean that maintenance duration has no effect on security of supply. At equal forced-outage risk, fewer maintenance days can only free up transmission capacity more of the year, which should reduce loss-of-load risk on average, in the same direction as for system costs. But loss-of-load hours are driven overwhelmingly by which specific lines a given random draw of forced outages happens to affect, a source of variance that 10 Monte-Carlo draws per scenario are not enough to average out. System costs aggregate smoothly over many hours and assets, so their systematic response to maintenance duration already dominates this sampling noise at 10 draws. Loss-of-load hours, concentrated on a small number of rare, high-impact events, would likely require a substantially larger number of draws for the same systematic effect to emerge clearly from the noise.

4.5.4 Conclusion on grid monitoring for system costs

Grid monitoring covers a broad range of technologies, from continuous line and substation sensing to predictive maintenance software, deployed differently across the TwinEU pilots. Rather than modelling any one of them individually, this study analyses a representative common outcome, a reduction in the number of planned maintenance days per transmission line, tested here as a sensitivity from 4 to 9 days.

Fewer maintenance days consistently reduce system costs, CO₂ emissions and curtailment, with a robust, monotonic relationship across every climatic year tested. Moving from 5 to 4 days saves on the order of 60 M€ per year, for instance, while moving to 9 days costs an additional 220 M€. Security of supply follows a less predictable pattern, loss-of-load hours vary between about 124 and 200 hours across the sweep without a clear monotonic trend, since with only ten Monte-Carlo draws per scenario the dispersion between random forced-outage realisations often exceeds the effect of maintenance duration

itself. As with the other levers studied, the measured benefit also concentrates unevenly, on a subset of countries and on specific transmission corridors rather than spreading uniformly across the network.

Set against Forecast Accuracy and Dynamic Line Rating, grid monitoring's system-cost effect sits in a similar range to Dynamic Line Rating, tens to a couple of hundred M€ per year for the increments tested, while Forecast Accuracy's effect is larger in absolute terms, several hundred M€ per year, reflecting a lever that acts on every hour of dispatch rather than only on network availability. All three studies share the same structural pattern. Benefits that look modest and diffuse at EU scale concentrate, in every case, on a limited set of countries or network elements. DLR concentrates on structurally congested corridors, Forecast Accuracy on smaller or import-dependent systems, and grid monitoring on the specific lines whose availability changes most.

4.6 Strategic Planning

4.6.1 Distribution network development plans

Distributed flexibility is recognised as an integral component of distribution network planning in the EU. Article 32 of Directive (EU) 2019/944 provides the legal basis for incorporating distributed flexibility into distribution network planning [41]. It requires Member States to enable and incentivise DSOs to procure flexibility services from resources such as distributed generation, demand response and energy storage where this can cost-effectively alleviate the need to upgrade or replace network capacity. Article 32(3) further requires Distribution Network Development Plans (DNDPs) to provide transparency on medium- and long-term flexibility services needed and to include demand response, energy efficiency, energy storage and other resources that the DSO intends to use as alternatives to system expansion.

In practice, distributed flexibility is already widely considered in European DNDPs, but the degree of integration varies substantially. The 2025 ACER/CEER *Guidance on Electricity Distribution Network Planning* [6] positions flexibility as a complementary element of network planning that should be assessed alongside conventional grid investments when addressing identified network capacity gaps. Flexibility may therefore enter the planning process as an alternative or temporary complement to reinforcement, for example by reducing or deferring an investment or by managing a capacity constraint until the planned reinforcement is commissioned. Grid reinforcement is nevertheless expected to remain the main solution for ensuring long-term network adequacy.

The role assigned to flexibility also depends on the type of network constraint. The ACER/CEER Guidance, drawing on a survey of National Regulatory Authorities (NRAs), finds that DSOs in almost three quarters of participating Member States consider flexibility useful for addressing RES driven congestion, around two thirds for load driven congestion, and roughly half for voltage related issues. The corresponding network service is directional: high renewable injection can create a need for downward flexibility, while high demand can create a need for upward flexibility. This shows that flexibility is increasingly regarded in DNDPs as a resource for addressing specific distribution network constraints rather than simply as a generic source of system flexibility.

However, the ACER/CEER assessment reveals a clear gap between considering flexibility and incorporating it quantitatively into network planning. According to the NRA responses, flexibility is considered in the DNDPs of all DSOs in the Flemish region of Belgium, Croatia, Denmark, Estonia, Finland,

Hungary, Lithuania, the Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia and Sweden, while some DSOs consider it in Austria and Germany. The Czech Republic, Italy and Luxembourg reported plans to incorporate flexibility in subsequent DNDP iterations. Despite this broad consideration, ACER and CEER identify only Denmark, Portugal, Slovenia and Sweden as having DNDPs that quantify flexibility needs in terms of power or both power and energy.

According to the Annex to the ACER and CEER *Guidance on Electricity Distribution Network Planning* [25], the level of detail in quantified flexibility needs differs considerably across the four identified countries. Portugal provides the most granular example: flexibility needs are quantified in both power and energy, differentiated by voltage level and geographical area, linked to representative time blocks, and specified in both upward and downward directions. The requirements are derived using load-flow and statistical analysis of forecasts, allowing flexibility needs to be associated relatively closely with the underlying network constraint. Denmark also includes quantified flexibility needs in power and energy in some DNDPs and distinguishes upward and downward requirements. However, the level of detail varies between individual DSOs. Some DNDPs differentiate by voltage level while others aggregate voltage levels, spatial information is generally reported for the overall DSO area, and temporal information is typically provided as one value per year. Slovenia quantifies flexibility requirements in power and distinguishes upward and downward directions, but the information is more aggregated. Requirements are reported for the entire DSO area, across all voltage levels, with one value per year. The Annex further notes that the underlying assessment was based on a pilot analysis covering a limited part of the system and subsequently generalised to the wider distribution system; the NRA therefore requested an improvement of the methodology. In Sweden, quantification is included in some DNDPs, but practices differ between DSOs. Power requirements may be reported for the whole DSO area or for individual geographical regions and are presented for the periods 0–2, 3–5 and 6–10 years. Most DNDPs quantify one direction of flexibility, while a smaller number provide both directions. The method used to determine the requirement is left to the individual DSO. Sweden therefore illustrates that even where flexibility is quantitatively incorporated into DNDPs, the degree of standardisation and granularity can remain limited. The contrast with the remaining countries is important. For example, the Netherlands, Poland, Finland and several other Member States already consider flexibility for one or more network needs, but their DNDPs do not provide quantified requirements. In such cases, flexibility is incorporated primarily as a planning principle or potential solution, rather than being translated into a specific requirement characterised by power, energy, location and timing. The Annex therefore indicates different degrees of integration across Europe: from no or planned consideration, through qualitative consideration as an alternative network solution, to quantified and increasingly location- and time-specific flexibility requirements. ACER and CEER identify the latter as the direction in which DNDP practice should develop. They recommend that planned flexibility needs are quantified in both power and energy and, where feasible, specified according to the required upward or downward direction, geographical location and voltage level, expected time of use, and the contractual mechanism through which flexibility would be accessed. The DNDP should also explain why flexibility is needed and how the requirement was assessed. Hourly time blocks are preferred where feasible, with annual values proposed as a minimum level of temporal detail.

Overall, distributed flexibility can be considered well established as a concept in DSO network development planning, but not yet consistently integrated as a quantified planning resource. Most countries covered by the ACER/CEER assessment already consider flexibility in at least some DNDPs or

intend to do so, demonstrating a broad shift towards considering non-wire solutions alongside conventional investment. Nevertheless, only four Member States were identified as publishing quantified flexibility needs, and even these differ markedly in spatial, voltage and temporal granularity. Portugal is the closest among the surveyed cases to a detailed, constraint-specific representation of flexibility, while Denmark, Slovenia and Sweden demonstrate different intermediate approaches. The evidence therefore suggests that the principal remaining gap is not recognition of flexibility, but its translation into explicit, locational, directional and time-specific requirements that can be directly incorporated into network planning decisions.

4.6.2 CBA

Cost-benefit analysis (CBA) provides DSOs with a structured basis for assessing how to address network needs efficiently while maintaining the required reliability and quality of supply. Electrification and distributed generation are changing network loading, while uncertainty over their development complicates investment decisions. In this context, flexibility can complement reinforcement by addressing specific constraints, deferring investments or providing an interim solution until new infrastructure becomes available. Economic assessment helps establish where these options create value and which combination of solutions is appropriate. ACER and CEER consequently recommend assessing flexibility alongside conventional investments within an integrated network planning process [6].

4.6.2.1 Regulatory framework

The European regulatory framework establishes a clear basis for this comparison. **Article 32 of Directive (EU) 2019/944** [41] requires Member States to provide a framework enabling and incentivising DSOs to procure flexibility services where these can cost-effectively reduce the need to upgrade or replace electricity capacity. Article 32(3) connects this operational role to network planning: distribution network development plans must provide transparency on medium- and long-term flexibility needs and consider demand response, energy efficiency, storage and other resources as alternatives to system expansion. These provisions establish the need to consider cost-effective alternatives, without themselves prescribing a detailed CBA calculation method.

A more explicit requirement concerning CBA methodologies follows from the **Energy Efficiency Directive (EU) 2023/1791**. Article 27(2) [42] requires Member States to ensure that transmission and distribution system operators apply the energy efficiency first principle in network planning, development and investment decisions. National regulatory authorities, or other designated authorities, must verify that the methodologies used assess alternatives through CBA and account for the wider benefits of energy efficiency, demand-side flexibility and investments contributing to climate change mitigation. Authorities may also provide methodologies and guidance for these assessments. This gives the evaluation a broader scope than a comparison of the DSO's direct expenditure alone.

4.6.2.2 Methodological framework

DSOs can to a certain extent draw on EU-level recommendations from sector organizations on how to compare flexibility with network reinforcements. However, most learnings can be drawn from national methods. Currently, only four Member States (Denmark, Portugal, Slovenia and Sweden) reported quantified flexibility needs in their DNDPs to ACER and CEER; three of these compared flexibility and reinforcement through a CBA [25]. General recommendations outline what to consider in the assessment,

while national methods provide practical tools for calculating costs and benefits and deciding which solution to use.

ACER and CEER's *Guidance on electricity distribution network planning (2025)* provides recommendations directly relevant to comparing flexibility with reinforcement. It recommends that DSOs develop a process for selecting cost-effective solutions to identified network capacity gaps and incorporate this process into their planning methodologies. For flexibility considered as a permanent solution, the assessment should explain how the costs and benefits of flexibility and network alternatives are determined, including impacts on network users providing flexibility, and how uncertainty is addressed. DNDPs should also identify the competing reinforcement option, where one exists, and present the analysis supporting the selected solution's cost-effectiveness [6].

At national level, more operational methods support specific DSO decisions. The following sections examine approaches to comparing distributed flexibility with network reinforcement in **Great Britain, France, Portugal and Sweden**. These examples cover common evaluation tools, methods developed by individual DSOs and assessments embedded in distribution network development plans (DNDPs).

In Great Britain, the **Energy Networks Association's Common Evaluation Methodology (CEM)** [104] provides a common approach and calculation tool for evaluating flexibility against reinforcement. It calculates the economic benefit of deferring reinforcement and supports comparisons between different deferral strategies. Such tools provide a basis for examining how general methodological principles are translated into the assumptions, evaluation criteria and procurement decisions used by network operators. In **France**, the analysis focuses on Enedis's economic assessment methods, including comparisons between network investment and renewable generation curtailment to increase hosting capacity. In **Portugal**, the DNDP approach combines probabilistic assessment of network constraints with CBA to evaluate flexibility as an alternative to conventional investment. In **Sweden**, ACER–CEER reports CBA use in some DNDPs; the analysis therefore examines selected DSO practices rather than assuming a single national calculation method.

Other initiatives offer complementary methodological lessons. For example, the JRC's [43] earlier smart grid CBA guidelines [43] illustrate how to define a baseline, identify beneficiaries and assess sensitivity to key assumptions; the European Commission's Recommendation C(2026)1486 [44] on designing CBA methodologies for the energy efficiency first principle provides a reference for considering wider societal benefits; and FlexPlan [45] demonstrates how reinforcement, storage and demand flexibility can be evaluated jointly across scenarios. These contributions can inform particular elements of an assessment, although their age, broader scope or research focus limits their direct applicability to current DSO decisions. The analysis therefore focuses on ACER and CEER's recommendations and country-specific methods for comparing distribution network reinforcement with flexibility.

4.6.2.3 Country-specific and DSO-specific approaches

The following sections examine how DSOs compare the costs and benefits of distributed flexibility with those of network reinforcement. EU-level recommendations provide a common starting point, but do not prescribe a single harmonised calculation method for this comparison. The analysis therefore first considers ACER and CEER's recommendations on distribution network planning, before examining the methods used in selected countries.

The analysis follows the same structure throughout:

- (1) the assessment methodology**, including the alternatives compared and the main assumptions;
- (2) the cost and benefit categories and evaluation criteria** used to select a solution; and
- (3) the reported results**, where available, including estimates of the economic value of distributed flexibility.

For ACER–CEER, the emphasis is on recommendations and the evidence summarised in its guidance. For the country cases, the emphasis is on practical application and published findings.

4.6.2.3.1 ACER and CEER's recommendations

ACER and CEER recommend that DSOs systematically embed the assessment of flexibility needs into their planning methodologies and develop methods for evaluating the potential and cost-effectiveness of flexibility solutions, considering the applicable regulatory framework. If flexibility is considered a permanent solution, the methodology should explain how the costs and benefits of both flexibility and the network alternative are determined, including costs for network users providing flexibility, such as potential revenue losses for generators with flexible connection agreements, and potential revenues for consumers providing flexibility. It should also explain how uncertainties associated with both alternatives are taken into account. Finally, DSOs should ensure that the flexibility-needs assessment in their distribution network development plans is sufficiently detailed and complies with the information and analysis requirements of the Flexibility Needs Assessment Methodology (FNAM).

4.6.2.3.2 Great Britain: ENA Common Evaluation Methodology

1. Assessment methodology

The Energy Networks Association's **Common Evaluation Methodology (CEM)** [104] provides a common approach and an Excel tool for British distribution system operators (DSOs) to compare network investment options. Its principal application is assessing whether procuring flexibility to defer reinforcement is more economic than proceeding with reinforcement. The following description refers to version 3.0, published in 2024.

The assessment starts by defining the network need and the available solutions. DSOs document the options considered, including those rejected before detailed costing, and explain their assumptions and selection rationale. For reinforcement deferral, projected peak loads are compared with asset capacity across different load-growth scenarios. DSOs then specify the flexibility required in each year and scenario, distinguishing availability from utilization and allowing for any necessary over-procurement. The underlying network studies and calculations of flexibility requirements are supplied by the DSO.

The tool compares the net present value (NPV) of the baseline and alternative strategies over different deferral periods. Under the principal use case, the alternative includes flexibility costs during the deferral period and reinforcement expenditure at a later date. The main benefit therefore arises from postponing expenditure, rather than assuming that the investment cost disappears entirely. The assessment covers the asset lifetime, normally 45 years, extending beyond the deferral period to capture the subsequent use of the reinforced asset.

The economic treatment follows Ofgem's CBA framework, including its treatment of total expenditure and the Totex Incentive Mechanism. Version 3.0 specifies discount rates of 3.5% for the first 30 years and 3% thereafter for most costs and benefits, with lower rates for safety impacts. The DSO-specific weighted average cost of capital is used separately to convert capital expenditure into annual costs.

Uncertainty is assessed by comparing strategies across load-growth scenarios. The tool also examines option value: procuring flexibility initially preserves the possibility of extending its use, reinforcing later or changing strategy as needs become clearer. This is evaluated through least-worst-regret and probability-weighted analysis. These features support decisions about both whether to use flexibility and how long to commit to it.

2. Cost and benefit categories and evaluation criteria

Before comparing costs and benefits, the CEM defines the service requirements through **load growth scenarios** and **flexibility requirements**. For reinforcement deferral, projected peak network load is compared with current asset capacity to determine exceedance per year per scenario. The DSO then specifies the flexibility needed to cover this exceedance, including any required over-procurement. The table below summarises the inputs and calculations described in the methodology.

Table 25: Common Evaluation Methodology (CEM) Service Requirements

CEM subsection	Element	Description and role in the assessment
Load growth scenarios	Load growth scenarios	The DSO defines scenarios through its network planning process to assess how network needs could evolve.
	Current year	The year in which the decision to reinforce needs to be taken.
	Current maximum capacity	The capacity of the asset being assessed, entered by the DSO.
	Forward-looking peak network load	Projected peak loading across the scenarios considered, entered by the DSO.
	Exceedance per year per scenario	Calculated by comparing peak network load with current asset capacity.
Flexibility requirements	Annual flexibility requirements per year per scenario	The DSO specifies the flexibility required for each year and scenario, covering both exceedance and any necessary over-procurement.
	Annual availability and utilisation volume	The DSO can enter these volumes directly.
	Days-per-year, hours-per-day and average hourly availability and utilisation requirement	Alternatively, the DSO can specify the requirements using these parameters.

	Workings worksheet	Provides space to document justifications and assumptions underlying external calculations for availability and utilisation.
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Once the service requirements are established, the CEM sets out the **basis of economic assessment**. This comprises standard inputs consistent with Ofgem's CBA framework, the time horizon and the treatment of total expenditure. Together, these determine how expenditure and relevant physical impacts are valued and compared over time.

Table 26: Common Evaluation Methodology (CEM) Inputs and Calculations

CEM subsection	Economic input or element	Treatment described in the CEM
Standard inputs	Customer Interruptions (CIs)	The CEM uses Ofgem's standardised monetary value per interruption. The DSO enters the number of interruptions associated with the intervention.
	Customer Minutes Lost (CMLs)	The CEM uses Ofgem's standardised monetary value per minute lost. The DSO enters the number of customer minutes lost associated with the intervention.
	Weighted Average Cost of Capital (WACC)	A DSO-specific value used to convert capital costs into annual costs.
	Discount rates	The model uses a Social Time Preference Rate (STPR) of 3.5% for periods up to and including 30 years and 3% thereafter. For safety impacts, it specifies a Health Discount Rate (HDR) of 1.5% up to and including 30 years and 1.2857% thereafter.
	Losses value	The CEM uses the standardised Ofgem monetary value per MWh lost to value reductions in electrical losses.
	Carbon prices	The CEM uses the BEIS traded carbon price, consistent with Ofgem's CBA, to value carbon emissions associated with network losses.
	Cost per injury/fatality	Where relevant, benefits from reducing or preventing injuries and fatalities are valued consistently with Ofgem's CBA, drawing on HM Treasury Green Book and HSE guidance. These inputs are generally not expected to be required when evaluating flexibility solutions.
Time horizon	Time horizon	The methodology assesses discounted cash flows over the asset lifetime, or 45 years. For reinforcement deferral, the calculation starts at the beginning of the deferral period and extends for 45 years after that period ends.
Totex treatment	Totex treatment	The CEM follows Ofgem's CBA template, applying the same Totex treatment, including the Totex Incentive Mechanism (TIM) to all costs.

Source: ENA CEM v3.0, Sections 4.1–4.3, pp. 10–11.

The CEM distinguishes between **baseline costs** and **alternative intervention costs**. The baseline normally involves network reinforcement, while alternative intervention costs reflect the cost to the DSO of the solution being assessed. The table retains this distinction and uses Appendix A.1.1 to detail the components of the alternative reinforcement-deferral strategy.

Table 27: Common Evaluation Methodology (CEM) Cost Categories

CEM category	Component	What is included and how it is treated
Baseline costs	Baseline intervention	Normally network reinforcement. Other costs, such as losses, customer interruptions, customer minutes lost or carbon emissions, may be specified where flexibility can defer or avoid them. These form the counterfactual for the comparison.
Alternative intervention costs	Deferred Reinforcement Costs	Reinforcement costs are the same as in the baseline but shifted by the number of deferral years.
	Upfront flexibility costs	One-off costs, such as establishing a flexibility market in a particular area. These are incurred regardless of the number of deferral years.
	Fixed flexibility costs	Annual costs that do not vary with the volume of flexibility procured, such as the annual cost of running a flexibility tender. These are included only during the deferral period.
	Availability and utilisation costs	Costs associated with procuring availability and activating flexibility. These are taken from the input worksheets and included only during the deferral period.
	Incentives and penalties	Relevant incentive and penalty inputs are included only during the deferral period.

Then, the CEM also accounts for the value of reinforcement deferral. The value of flexibility primarily derives from the time value of money associated with postponing capital expenditure on network reinforcement. The CEM compares the NPV of discounted cash flows for the baseline reinforcement strategy with those of the alternative flexibility strategy across forward-looking load growth scenarios. In the reinforcement-deferral application, the alternative includes flexibility expenditure during the deferral period and reinforcement expenditure incurred later. The benefit therefore reflects the economic value of delaying investment, rather than assuming that the investment is permanently avoided.

The methodology also allows DSOs to explore the option value created by retaining flexibility in future decisions under uncertain load growth. After an initial flexibility contract, the DSO can procure further flexibility, reinforce or pursue another strategy. The CEM assesses strategies across scenarios using two approaches: Least Worst Regret, which identifies the strategy that minimises the worst regret across the modelled scenarios, and Weighted Average, which uses probabilities assigned to scenarios to identify the strategy with the highest expected net benefit. These approaches support the evaluation of different

flexibility procurement strategies and their value under uncertainty. More details can be found in Appendix B.2, p. 29.

Alongside intervention expenditure and the value of reinforcement deferral, the CEM considers **wider network and societal impacts**. CEM distinguishes between Impact on losses, Carbon emissions and Other societal impacts. These effects are assessed for the baseline and alternative interventions and may strengthen or weaken the economic case for flexibility. The table below follows these three categories and describes the components identified in the text.

Table 28: Common Evaluation Methodology (CEM) network and societal impacts

CEM subsection	What is accounted for	Valuation and qualifications
Impact on losses	Differences in electrical losses between network interventions.	The DSO enters the expected reduction in losses for the baseline and alternative scenarios. The tool uses Ofgem's standardised £/MWh value to incorporate these differences into the comparison.
Carbon emissions	Carbon emissions resulting from network losses.	The CEM follows Ofgem's CBA treatment to quantify these emissions.
	Emissions associated with the energy used to release capacity under each option.	The tool allows the DSO to include the carbon value of different network solutions.
	Embedded emissions in the baseline reinforcement option.	Where flexibility defers reinforcement, the associated embedded emissions are also deferred. The carbon value in £/tonne remains aligned with the baseline year rather than the year of deferred reinforcement. The report acknowledges that this approach may require further consideration.
	Additional emissions from alternative network interventions.	These can be incorporated in the model's "other emissions" section.
Other societal impacts	Other societal impacts included in the Ofgem CBA template and retained in the CEM.	The report generally does not expect these impacts to differ between network solutions and therefore does not expect them to be used. Where relevant, the <i>Workings</i> worksheet can document justifications and assumptions underlying external calculations.

Finally, the CEM combines service requirements, expenditure profiles and monetised impacts to compare strategies across scenarios and deferral durations. The resulting outputs indicate the net benefit of flexibility relative to the baseline, the maximum flexibility price justified by the comparison and the value associated with uncertainty. The table below follows the five outputs identified.

Table 29: Common Evaluation Methodology (CEM) Comparison of Strategies

Output		Description
Benefit strategy	by	The net benefit of the flexibility solution relative to the baseline, for specified baseline costs and user-defined flexibility costs, including availability, utilisation and annual fixed costs.
Insights and Reporting	and	Summary tables of the <i>Benefit by strategy</i> results and comparisons of strategies across scenarios using Least Worst Regret and Weighted Average Benefit analysis.
Ceiling price		The maximum cost of the flexibility solution before it becomes less economic than the traditional asset solution, for a given set of baseline costs.
Option value		Results distinguishing the intrinsic value (Best view) from the uncertainty value (or extrinsic value) of flexibility relative to the baseline, for specified scenario probabilities.
Summary CBA		The detailed CBA calculations underlying the assessment, which the user can inspect, although the report does not identify these as a key output.

3. Reported results and practical application

The CEM report describes the tool's outputs and provides illustrative charts, but does not report an aggregate estimate of flexibility's economic value across Great Britain. Its outputs are specific to the network need, cost assumptions, flexibility requirements and scenarios entered: net benefits by strategy, ceiling prices, preferred strategies under uncertainty and the contribution of option value.

UK Power Networks provides evidence of practical application. Its **2025/26 Distribution Network Options Assessment methodology** [46] states that investment decisions continue to be grounded in the ENA CEM CBA.

Ofgem's assessment of UK Power Networks' 2024/25 [47] performance reports a **56% reduction in projected RIIO-ED2 load-related expenditure**, discussing flexibility alongside energy efficiency and improved local planning inputs. This supports the practical value of adapting investment decisions to evolving needs. However, the percentage reflects a broader planning outcome and should not be interpreted as a standalone estimate of net savings attributable exclusively to flexibility or the CEM.

4.6.2.3.3 France CBA

1. Assessment methodology

Scope of the flexibility assessment

In the preliminary document for its 2023 Network Development Plan (NDP) [33], Enedis considers flexibility as a potential alternative to conventional network investment and states that, for connections and reinforcements, it seeks the most economically efficient solution, using flexibility where it can substitute for investment. The scope of flexibility considered in the NDP is therefore specifically focused on cases in which flexibility can generate investment savings, either for network connections or reinforcements.

As summarised in Table 30, the NDP distinguishes six flexibility use cases, of which three are considered relevant to connection or reinforcement investment savings.

Table 30: Six flexibility use cases and inclusion in CBA

Flexibility case	Purpose	CBA treatment
National flexibility	Balancing supply and demand at national level, principally under RTE's responsibility.	Not included in the investment CBA
Flexibility for the transmission system	Supports optimisation of transmission network operation.	Not included in the investment CBA
Local flexibility for short-term operational needs	Addresses temporary operational needs, such as avoiding local outages or facilitating planned works.	Not included in the investment CBA
Alternative connection with power modulation (ORA-MP) <i>(Local flexibility, individual benefit, single connection)</i>	Allows an individual user to connect without the network adaptation works required to guarantee the full requested power at all times. In return for a lower-cost connection, the user accepts possible curtailment without financial compensation, within limits agreed when the connection offer is signed.	Separate customer-level economic assessment
REFLEX <i>(Local flexibility, collective benefit, shared connection)</i>	Allows more production installations to connect to shared network infrastructure by using flexibility during specific periods, through local flexibility tenders or, where necessary, generation curtailment.	Separate collective CBA for shared producer connections

Local flexibility to defer reinforcement	Uses local flexibility to postpone a reinforcement investment that Enedis would otherwise undertake because of network constraints arising from excess generation or consumption. Flexibility is contracted through a tender when its cost and technical characteristics compare favourably with the planned reinforcement.	Separate collective CBA for reinforcement deferral. Detailed methodology provided in the NDP
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The three cases should therefore not be treated as a single CBA.

Under ORA-MP, the customer chooses an alternative to the reference connection offer (ORR)¹ and can benefit from a lower connection cost and/or shorter connection time, while accepting possible limitations on consumption or injection without financial compensation. The customer therefore weighs the connection benefit against the consequences of potential curtailment.

REFLEX, by contrast, concerns shared connection infrastructure for (renewable) generation and is assessed from a collective perspective. Its initial CBA compares two scenarios: a reference scenario in which the network is developed according to standard connection rules without flexibility, and an alternative case in which generation curtailment is allowed. The assessment then seeks to identify the economic trade-off between the cost of curtailment and the investment savings resulting from reduced network investment needs.

The third case concerns local flexibility used to defer reinforcement investment. Here, Enedis would otherwise undertake an investment to resolve a local network constraint, but assesses whether procuring flexibility can economically defer that investment. The flexibility is remunerated and is selected through a market process where it can provide the required service at a cost below the value of the investment deferral. While Enedis considers reinforcement needs arising from both excess generation and consumption when identifying flexibility opportunities, the detailed two-step assessment described in the NDP is specifically presented for investment deferral in response to withdrawal-related constraints, i.e. constraints associated with electricity consumption. The methodology presented below therefore relates specifically to this case.

Flexibility is not considered as a substitute for every type of network investment. Enedis states that it systematically assesses flexibility opportunities where reinforcement of primary substations or MV feeders is required because of constraints resulting from excess generation or consumption. Where investment is required for other reasons, such as asset relocation at the request of a third party or obsolescence, investment deferral through flexibility is not considered.

¹ The reference connection offer (ORR) is Enedis' standard connection solution, designed to guarantee the user's requested connection power without relying on flexibility, and used as the baseline against which alternative flexible connection options are assessed.

Across these cases, Enedis emphasises that the value of flexibility is intrinsically local, as a flexibility resource must be located at the appropriate point in the network and be available at the required time. Its value therefore depends on the precise electrical configuration, including network topology and customer load at the relevant location, as well as on the planned investment and the characteristics offered by the flexibility service provider.

Economic assessment of flexibility for reinforcement deferral

For local flexibility used to defer reinforcement in response to withdrawal-related² network constraints, Enedis assesses whether flexibility can provide an economic alternative to the reference network investment.

The assessment is underpinned by three broader economic principles. First, local flexibility transfers part of the risk from network development to network operation and from resources controlled by Enedis to services provided by network users. The reliability of the flexibility service must therefore be taken into account, since an investment provides the required network capability by design whereas flexibility represents a commitment to provide a future service. Second, the comparison requires the timing and duration of the underlying network constraint to be identified. Third, flexibility and investment must be compared on the basis of their respective effects. Reinforcement not only resolves the identified constraint but can also provide additional operating configurations that improve quality of supply and reduce technical losses.

Within this framework, Enedis uses a two-step process to determine whether flexibility should be contracted. First, the optimal reference investment is compared with ideal flexibility³ on the basis of their technical and economic balances to identify whether a flexibility opportunity⁴ for deferring reinforcement exists. Second, the identified opportunity is tested through a call for tenders, in which Enedis assesses actual flexibility offers in terms of the service and price offered. Flexibility is selected only where the collective value of the offer, taking into account residual lost load⁵ and the cost of the flexibility service, is better than that of the network reinforcement solution.

Before flexibility is assessed, the optimal investment strategy is identified in advance. Enedis first determines the technical network adaptation solution that provides the best long-term balance between costs and benefits for the community⁶ and then determines its optimal implementation year. The optimal year, denoted N, balances the cost of bringing the investment forward rather than investing in year N+1 against the benefits of resolving lost load⁷ earlier and reducing network losses. Postponing the investment to year N+1 avoids this cost of bringing the investment forward but entails an additional year of lost load and losses.

² Withdrawal-related constraints are associated with electricity consumption/load on the network, rather than with generation injection.

³ Ideal flexibility refers to a hypothetical flexibility service assumed to have no limits on power or duration when a network constraint occurs, perfect reliability, an ideal location and an ideal activation time. For initial comparison with reference investment, its cost is assumed to be zero.

⁴ Flexibility opportunity refers to a case in which the use of flexibility can potentially defer a planned reinforcement and performs better than the reference reinforcement solution in the initial technical-economic assessment.

⁵ Residual lost load refers to the portion of electricity demand that remains unserved after activation of the flexibility service.

⁶ Community refers to the collective socio-economic perspective used in the CBA, covering the overall costs and benefits for the electricity system and its users rather than only the financial impact on Enedis or on an individual market participant.

⁷ Lost load refers to electricity demand that is not supplied because of a power-supply interruption or network constraint.

The first step is to identify a flexibility opportunity. Enedis compares the optimal reference investment with ideal flexibility by comparing their technical and economic balances. For this initial assessment, flexibility is assumed to have no limits on power or duration when a constraint occurs, perfect reliability, an ideal location and activation time, and zero cost. A flexibility opportunity is identified where, and for as long as, this ideal flexibility performs better than the reinforcement solution as conditions in the network area evolve, including growth or decline in load and the possible disappearance of flexibility potential.

Not all network constraints constitute flexibility opportunities. Enedis notes that some constraints still require investment because they arise from factors such as network topology, regulatory obligations, asset renewal, undergrounding decisions, requests for quality improvements or the need to develop new projects. Flexibility can therefore address only part of the constraints identified by Enedis.

The economic comparison can be represented as a choice between investing in year N and investing in year N+1 while using flexibility in year N. Enedis compares the cost of bringing the investment forward, together with lost load and network losses under the year N investment strategy, with the lost load and network losses under the deferred investment strategy (N+1), reduced through the use of flexibility in year N. The preferred strategy is the one with the lower overall cost for the community. Because all costs before the optimal investment year N and after year N+1, up to the assessment horizon, are identical under the two strategies, comparing the total costs for the community between the two strategies is equivalent to comparing the costs of lost loads and losses of the two strategies at the optimal year N.

At the optimal investment date, Enedis estimates the benefits provided by ideal flexibility. If flexibility reduces lost load but the investment strategy still provides the better benefit for the community, investment deferral is not considered. If flexibility produces a better overall benefit for the community than the investment strategy, investment deferral becomes possible.

Where deferral is possible, Enedis calculates the community's willingness to pay for the flexibility service. The willingness to pay is derived from the difference between the impact of flexibility and the effectiveness of the investment and represents the value available to cover both the cost of implementing the use of flexibility and the purchase price of the service. The value ultimately created for the community is therefore the willingness to pay less these implementation and procurement costs. Enedis notes that the willingness to pay can equivalently be understood as the value to the community of a free flexibility service with zero implementation cost.

Flexibility is considered for investment deferral only where it provides a better economic outcome for the community than the optimal investment solution. If this is demonstrated for ideal flexibility, Enedis defines the characteristics of the required service, including its location, power, duration, activation time, time windows and availability, and then tests whether such a service can be procured from the market under economically acceptable conditions.

The second step is a call for tenders. Enedis publishes the identified flexibility opportunity, including its geographical location and the specifications of the required service, and evaluates offers from flexibility service providers according to the service and price offered. If an offer is technically and economically superior to the traditional network solution, Enedis procures the flexibility service.

For investment deferral in response to withdrawal constraints, the service is contracted with capacity reservation. In exchange for fixed remuneration, the provider guarantees the availability of the required flexibility for a period specified by Enedis. At the investment decision stage, Enedis can therefore choose between two economic alternatives with a guaranteed outcome: network reinforcement or a flexibility service with capacity reservation that allows the investment to be deferred. Enedis also requires flexibility service providers to meet a result obligation and provides for penalties to address the risk of non-delivery.

The approach presented in the NDP forms part of a broader methodological development by Enedis and the association of French electricity distributors (ADEEF). Their 2017 Economic Assessment of Smart Grids report [48] assessed the technical and economic benefits of flexibility and quantified its potential value for the community, including for withdrawal and injection constraints. Subsequent Enedis publications developed the relevant flexibility use cases and procurement arrangements, while the 2023 NDP sets out the process used to identify investment deferral opportunities and procure local flexibility services.

2. Cost and benefit categories and evaluation criteria

Enedis assesses network solutions from a collective socio-economic perspective, considering the overall costs and benefits for the electricity system and its users rather than only the direct financial cost to Enedis. The 2017 methodology was designed so that smart grid solutions could be assessed using criteria consistent with conventional network investment decisions. The main economic components are summarised in Table 31. Their relevance differs depending on the flexibility application.

Enedis uses three main technical-economic parameters in its investment studies to express different network impacts on a common economic basis and compare costs and benefits over time: the value of lost load (VOLL), the discount rate, and the long-term energy cost.

The VOLL represents the socio-economic cost attributed to an interruption of electricity supply. In the 2023 NDP, it has two components: a variable component expressed in €/kWh, representing the variable or proportional part of the inconvenience that depends on the duration of the outage, and a fixed component expressed in €/kW, representing the inconvenience regardless of the duration of the outage. Enedis reports current values of €31/kWh and €10/kW. Where customers receive advance notice of the interruption, lower values are used because they can take measures to reduce its impact: €21/kWh and €5/kW. The values are derived from surveys of electricity consumers and reflect direct and indirect economic costs as well as less directly monetisable effects such as loss of comfort.

The discount rate is used to compare costs and benefits occurring at different points in time. The NDP reports a 4.5% socio-economic discount rate, based on France Stratégie recommendations for public investment appraisal, and notes that the value was under review at the time of publication. Enedis also stresses that this is a socio-economic discount rate rather than a financial interest rate or weighted average cost of capital. The same 4.5% rate was used in the 2017 Smart Grids CBA, which assessed costs and benefits to a 2030 horizon.

Table 31: Main economic components

Economic component	Treatment in the Enedis assessment
Network investment and timing	Includes the cost of the conventional network solution and the economic effect of undertaking it earlier or later. For reinforcement deferral, flexibility can create value by postponing rather than permanently avoiding investment.
Lost load / quality of supply	Electricity demand that cannot be supplied is assigned an economic cost. Reinforcement may also provide wider quality-of-supply benefits, including improved restoration possibilities following incidents.
Network losses	Technical electricity losses are monetised and included because alternative network solutions can affect their level. Reinforcement may reduce losses and therefore provide an additional economic benefit.
Flexibility implementation and service costs	For reinforcement deferral, the economic value available for flexibility must cover both the cost of implementing its use and the price paid to the flexibility provider.
Operation and maintenance	Recurrent operating and maintenance expenditure is included where it differs between the alternatives.
Residual value, renewal and asset lifetime	The assessment accounts for renewal of shorter-lived equipment and the remaining value of assets whose useful life extends beyond the assessment period.
Non-injected energy	For generation-side flexibility, the economic cost of curtailed generation is included. This is particularly relevant to REFLEX, where reduced network investment is compared with the cost of generation curtailment.

The long-term energy cost is used principally to value non-injected energy⁸ and the electricity required to compensate for technical network losses. The 2023 NDP does not provide a single numerical value, but states that Enedis relies on external references for the long-term market cost of energy; these references also incorporate a market value for CO₂ emissions. The earlier 2017 study provides an indication of the assumptions used at that time for non-injected energy: the cost of replacement energy was approximated by the marginal cost of electricity generation, at around €30/MWh at the time of the study and projected at €90/MWh for 2030.

⁸ The non-injected energy is the energy that a producer could have fed into the grid but that is lost for some reason. For instance, this may occur when a network equipment failure leads to the temporary disconnection of the producer's installations. It can also happen when the injection is interrupted by an instruction sent by the DSO, such as in the case of an ORA with power modulation.

The main evaluation criterion is the overall economic outcome from a collective perspective. For reinforcement deferral, flexibility is preferred only where it provides a better economic outcome than the optimal reinforcement strategy after accounting for the relevant costs and benefits. The willingness to pay defines the maximum value available for implementing and procuring the flexibility service while retaining a collective benefit⁹.

The evaluation criterion differs for the other flexibility applications. For REFLEX, the assessment compares network-investment savings with the economic cost of generation curtailment, while ORA-MP is primarily based on the connecting customer's trade-off between the benefits of an alternative connection and the consequences of possible power limitations.

3. Reported results and practical application

Reinforcement deferral through local flexibility

The 2017 study provides the main quantitative estimate of the economic value of flexibility for deferring reinforcement in response to withdrawal constraints. The methodology was applied to a set of actual primary substation reinforcement cases for which conventional reinforcement had already been identified as the optimal reference strategy. Under the assumptions used in the study, the maximum collective surplus associated with flexibility ranged from €0 to €24/kW per year of investment deferral, or, expressed in energy terms, from €0 to €11,600/MWh. The corresponding flexibility requirements ranged from 0 to 16 MW, with an estimated average useful activation duration of 0 to 186 minutes per year. The capacity- and energy-based values are two alternative expressions of the same economic value and should not be added together.

These values represent the maximum collective surplus before the costs of providing flexibility are deducted. They can therefore be interpreted as the maximum implementation cost below which flexibility would remain economically preferable to the reference investment, rather than as expected flexibility market prices. The estimates should also be regarded as upper bounds because the modelling assumes, among other things, perfect flexibility response and the ability to locate flexibility where it is most useful.

The sensitivity analysis confirms that the value is highly case specific. The unit collective surplus is highest for a one-year investment deferral and generally declines for longer deferrals, partly because increasing load requires more flexibility and because future benefits are discounted. Longer mobilisation times can also substantially reduce the value of flexibility. Location is particularly important: when flexibility was modelled as being distributed homogeneously across the network rather than optimally located, the estimated maximum collective surplus fell to €0–6/kW/year in the cases examined. Enedis therefore concludes that the value depends on both the characteristics of the constrained network area and the characteristics of the flexibility service, making it impossible to determine a single value in advance.

The 2023 NDP provides an important update on the practical potential of this application. Since the end of 2021, Enedis has systematically analysed flexibility opportunities for MV projects and associated primary substations affected by consumption-related constraints. The NDP reports that the potential

⁹ Collective benefit refers to the socio-economic benefit for the electricity system and its users as a whole and is used here in the same sense as Enedis' term "community".

identified for cases in which flexibility is both technically and economically relevant for investment deferral remains limited.

Generation-side flexibility and REFLEX

The 2017 study estimated that generation curtailment could enable around 720 MW of additional generation capacity to connect to existing networks by 2030. For cases where the solution was economically relevant, the estimated net gain was approximately €90,000/MW, corresponding to around €65 million in total national benefits and a reduction in renewable integration costs of about 20%.

The 2023 NDP reports larger benefits for REFLEX. Enedis estimates that it could reduce required network works for new renewable generation by 30% by 2035, equivalent to around €300 million in cumulative investment savings. The associated curtailment would remain below 0.06% of the generation potential of newly connected installations, with an estimated cost of approximately €50 million, resulting in a net collective benefit of around €250 million. The ten primary substations included in the REFLEX experiment could also provide approximately 210 MW of additional connection capacity.

ORA-MP and practical market evidence

For ORA-MP, the reports do not provide a comparable aggregate estimate of economic value. Its benefit is customer-specific, reflecting the trade-off between a potentially cheaper and/or faster connection and the consequences of accepting possible limitations on consumption or injection.

Overall interpretation

Taken together, the results show that Enedis does not identify a single economic value for distributed flexibility. For withdrawal-related reinforcement deferral, the 2017 results indicate an upper-bound value of €0–24/kW/year of deferral or €0–11,600/MWh, with substantial variation according to location, mobilisation time and network conditions. The 2023 NDP indicates that practically identifiable reinforcement deferral opportunities remain relatively limited. By contrast, generation-side flexibility shows substantially larger aggregate potential: REFLEX is estimated to provide a net collective benefit of around €250 million by 2035, primarily through reduced shared network investment while requiring only very limited generation curtailment.

4.6.2.3.4 Sweden CBA

In Sweden, the regulatory framework requires DSOs to consider alternatives to conventional network investment when preparing their network development plans. Under the Swedish Energy Markets Inspectorate's (Ei) regulations and associated guidance [49], DSOs must report planned investments and expected needs for flexibility services and other resources that may serve as alternatives to network expansion. They must also explain how they have identified the most cost-effective solution when comparing network investment with alternative measures. However, the regulatory framework does not prescribe a common detailed CBA methodology to be applied by all DSOs.

Several national-level studies provide relevant methodological examples. Ei's 2021 report *Utvärdering av kostnader och nyttor av smarta elnät* (Ei R2021:06) [50] applies a CBA-based approach and includes a quantitative comparison between meeting future transfer requirements through conventional network expansion and using demand side flexibility alongside network capacity. It therefore provides an official analytical example of how the economic effects of flexibility and reinforcement can be compared, but it

is not a prescribed DSO methodology. More applied approaches are provided by the FlexAbility project [51], which quantifies network constraints and compares the cost of procuring the required flexibility with conventional reinforcement, and by the 2026 Energiforsk study *En holistisk nätutvecklingsstrategi* [52], which incorporates such economic comparisons into a broader DSO decision process considering cost, reliability, lead time and available flexibility. These studies provide useful methodological guidance but are research and analytical studies rather than formal methodologies that Swedish DSOs are required to follow.

A more direct example of DSO practice is provided by E.ON Energidistribution's *Network Development Plan 2025–2034* [53]. E.ON describes a valuation approach used to assess flexible solutions against conventional network investment on a case-by-case basis. For existing network assets, the assessment considers the value of continuing to use the asset over its full economic lifetime. For planned new or reconstructed assets, E.ON considers the additional depreciation costs associated with the investment. These values are compared with the cost of a flexibility solution capable of addressing the same network constraint, and reinforcement may be deferred or avoided where flexibility is more cost-effective. However, the plan describes only the main valuation logic and does not set out a detailed CBA methodology or the calculation parameters used to undertake the comparison.

E.ON also states that it is developing the valuation model to incorporate wider socioeconomic effects, including the value of enabling customers to connect earlier and avoiding climate impacts associated with materials for new network assets. The network development plan does not publish individual CBA results or a standard monetary value of flexibility.

Overall, the Swedish approach is characterised by a regulatory requirement to identify and justify the most cost-effective solution rather than by a standardised national CBA methodology. National studies provide CBA-based and techno-economic methods for comparing flexibility with reinforcement, while E.ON provides evidence that such economic comparisons are incorporated into actual DSO planning. However, the publicly available E.ON material does not provide sufficient methodological detail to constitute a complete CBA framework.

4.6.2.3.5 Portugal CBA

1. Assessment methodology

E-REDES assesses flexibility against the conventional network investment, i.e. the reinforcement that would otherwise be implemented to address the identified network need [26]. As a first step, conventional network alternatives are assessed through cost-benefit analysis using INVESTE, E-REDES' economic-analysis tool for comparing investment alternatives. The assessment is carried out in constant prices and on the basis of total investment costs, while relevant benefits are monetised and discounted over time. Demand uncertainty is tested through three scenarios (Inferior, Central and Superior, representing lower, central and higher demand-development assumptions) and the alternatives are compared using economic indicators including B/C (relação benefício/custo; benefit/cost ratio, BCR), VAL (valor atualizado líquido; net present value, NPV), TIR (taxa interna de rentabilidade; internal rate of return, IRR), and TRI (taxa de rentabilidade inicial; initial rate of return).

Building on this investment assessment, E-REDES evaluates whether flexibility can provide a more economical alternative to, or allow the deferral of, the conventional reinforcement [28]. The methodology

uses a discounted cash-flow (DCF, cash-flows atualizados) comparison between the investment-only solution (VAL_I) and a hybrid solution combining investment and flexibility (VAL_F). The flexibility need is characterised by the magnitude of the network constraint, its expected duration and its probability of occurrence. Flexibility is economically viable where the NPV (VAL) of the hybrid solution is at least equal to that of the investment solution ($VAL_F \geq VAL_I$). This comparison determines the maximum economically acceptable cost of flexibility (CF*), i.e. the highest flexibility cost at which using flexibility remains economically preferable to conventional reinforcement.

E-REDES also complements this economic comparison with a risk-based planning criterion. Investment may be deferred where the existing network can satisfy demand for 95% of the time, with flexibility used to manage the remaining periods of constraint. If the required flexibility cannot be obtained from the market, the conventional investment is implemented.

2. Cost and benefit categories and evaluation criteria

The economic comparison accounts for the costs and benefits of conventional reinforcement and of using flexibility to defer that reinforcement. The principal categories are summarised below.

Table 32: Main economic categories

Category	Treatment in the E-REDES assessment
Network investment cost	Conventional investment is assessed at total cost, including materials and labour plus direct, transversal and financial charges.
Reliability / END benefit	Investment benefits include reductions in reliability costs. Overloads and non-compliant voltage conditions are valued as END (energia não distribuída; energy not distributed). For flexibility, the operational benefit is measured through the corresponding reduction in curtailed or non-distributed energy while the investment is deferred.
Technical-loss reduction	Reduced network losses are monetised as a benefit of conventional reinforcement. In the direct flexibility comparison, E-REDES states that flexibility makes an insignificant contribution to this benefit.
Investment deferral	A principal benefit of flexibility is postponing the conventional investment, thereby delaying the associated capital expenditure.
Residual value	The remaining value of an investment at the end of the assessment horizon is included where its useful life extends beyond that horizon. Deferring investment increases its residual value within the assessment period.
Flexibility-service cost	Flexibility costs comprise fixed costs, associated with keeping resources available, and variable mobilisation costs when the resources are activated.

The conventional reinforcement and flexibility-based solutions are compared on a discounted net present value (VAL; NPV) basis. Flexibility is economically viable where the VAL (NPV) of the hybrid investment-and-flexibility solution is at least as high as the investment-only solution ($VAL_F \geq VAL_I$). This determines the maximum economically acceptable cost of flexibility, while the DSO's actual procurement price should be below this limit so that flexibility produces a positive collective benefit relative to conventional reinforcement.

3. Reported results and practical application

For the network development projects assessed, E-REDES found that the benefits specific to flexibility were generally lower than benefits obtained exclusively from conventional reinforcement, particularly reductions in technical losses. Consequently, the reservation price of flexibility was generally negative. E-REDES notes that this result was observed even in cases expected to favour flexibility, including where flexibility would be used only for a few years.

Flexibility is nevertheless used as a means of deferring investment where the network can meet demand for 95% of the time. On this basis, E-REDES identifies six security-of-supply projects for which flexibility requirements are specified. In the more detailed assessment of security-of-supply projects, flexibility was considered a viable alternative for four of the five projects addressing non-guaranteed power under normal operating conditions, and these investments were scheduled to start in 2028, allowing short-term procurement of flexibility to be considered. For Beja and Bragança, flexibility requirements had already been published to the market, but no offers fully met the requirements.

For asset renewal, E-REDES found only one case in the assessed portfolio where flexible management of loads reduced the relevant risk: SE Valença. In this case, flexibility allowed the investment to be deferred from 2026 to 2029.

The PDIRD-E 2024 proposal states that flexibility alternatives allow seven projects to be deferred. Annex C.4 [28] provides the corresponding technical requirements, including required capacity, activation duration, annual activation probability and service windows, but does not report project specific monetary values for the economic value or maximum acceptable cost of flexibility.

4.7 Local Flexibility Markets

4.7.1 General characteristics of LFMs

LFMs in Europe are developing as explicit mechanisms through which system operators procure flexibility from distributed energy resources to address local network needs. The surveyed initiatives differ in maturity, design, participants, services and technical scope, but overall, the landscape remains dynamic and experimental [54].

Most LFMs are still pilots or preparatory initiatives, testing market designs, operational processes, flexibility products and regulatory approaches. Only a smaller number operate as established markets within routine system operations. Market age does not necessarily indicate maturity, as newer initiatives may build on existing platforms and expertise. Flexibility is usually procured by individual distribution system operators, allowing them to develop roles, processes and governance gradually. However,

cooperation between DSOs, and between DSOs and TSOs, is increasing where network challenges cross system boundaries or greater scale and standardisation are needed.

Congestion management is the main flexibility service procured by LFM, reflecting constraints caused by electrification, distributed generation and changing consumption. Some initiatives also address voltage control or combine local services with balancing. Others are proactive, preparing operators and market participants for future flexibility needs before congestion becomes severe. Flexibility needs are concentrated mainly at medium- and high-voltage levels. Low-voltage markets are more difficult because needs are highly localised and require extensive monitoring, control and communication. Nevertheless, aggregation is enabling some low-voltage resources to participate. Markets generally allow consumption, generation and storage, although minimum bid sizes, metering requirements and engagement challenges can limit access for smaller assets. Platforms are developed either in-house or by commercial providers.

Overall, European LFM are gradually moving from experimentation towards more operational and coordinated models. Further development will depend on greater standardisation, improved DSO–TSO coordination, better access for smaller assets, stronger digital infrastructure and integration with broader electricity-market arrangements.

4.7.2 Comparative Analysis of Selected European Cases

To provide a comprehensive overview of LFM initiatives in the EU, desk research was conducted on 17 initiatives based on publicly available data. The results of the analysis are presented in Table 33. Some LFM initiatives, including ORES-LFM, Flex.ON, the Spanish Regulatory Sandbox, and Swiss TDC, are relatively new, still under development, or not yet fully implemented; therefore, data for these LFMs are not yet available. These initiatives are shaded in light orange in Table 33. In contrast, some LFM initiatives are sufficiently mature, but detailed data are not publicly available. These include FinFlex, Fleksibilnost, and Sthlmflex, which are shaded in light blue. For the remaining LFM initiatives, publicly available data is presented for all or some of the output indicators.

The main indicators used to evaluate LFM initiatives are market maturity, the number of qualified and active flexibility service providers (FSPs), and the volume and price of reserved and activated flexibility. Market maturity is measured as the time elapsed since the initial opening of the market and therefore indicates the number of years the LFM has been operational. The number of qualified and active FSPs provides insight into market participation and potential liquidity, reflecting both the market's ability to attract participants and the availability and readiness of FSPs capable of providing the required services. Reserved flexibility capacity (MW) and activated flexibility volume (MWh), measured over a specified period, indicate realised demand from system operators and provide insight into the scale and activity of the market. However, they may underestimate the underlying or potential demand for flexibility where available supply is insufficient, or where system operators are procuring and activating only limited volumes as part of pilot or testing activities. Finally, the average prices of reserved and activated flexibility provide insight into realised procurement costs and observed price levels within each LFM initiative. Note these prices should not only be interpreted as direct measures of the underlying economic value of flexibility, as they may also reflect pilot objectives or budgets, market maturity and efficiency, limited competition, scarcity of flexibility supply, or the availability and cost of alternative options for the system operator.

Table 33: Overview LFM initiatives represented in desk research (LF = Long Flex, MU = Max Usage, SF = Short Flex)

LFM Initiative	Maturity [year]	#Qualified FSPs	#Active FSPs	Reserved capacity (MW)	Activated volume (MWh)	Price reservation (€/MW)	Price for activation (€/MWh)
ORES-LFM (BE-WAL)	NA	NA	NA	NA	NA	NA	NA
Flex.on (HU)	0.5	NA	NA	NA	NA	NA	NA
Regulatory Sandbox – Mercados Locales (ES)	NA	NA	NA	NA	NA	NA	NA
Swiss TDC (CH)	NA	NA	NA	NA	NA	NA	NA
FinFlex (FI)	1	NA	NA	NA	NA	NA	NA
Fleksibilnost (SI)	4	NA	NA	NA	NA	NA	NA
Sthlmflex (SE)	4	NA	NA	NA	NA	NA	NA
Marktflexibilitätsdiensten (BE-VLG) [55]	1.5	18	8	113	200	70 (LF); 150 (MU)	358 (SF); 129 (MU)
UKPN Local Flexibility Market (UK) [56]	5	35	23	7952	14747	119	272.5
Marché de Flexibilités Locales (FR) [57]	6	4	4	20.5	NA	NA	NA
EDGE (IT) [58]	2	6	≥2	18.95 requested; 4.6 qualified; 2.6 contracted	NA	91.5	NA
Romeflex (IT) [59]	2.5	15	12	15 (Jan-May); 30 (Jun-Dec)	NA	4.57	400
GOPACS (NL) [60]	8	115	41	NA	5467	NA	391

Euroflex (NO) [55]	6	33	23	9,347	1,648	17 (LF); 129 (MU)	562 (SF); 154 (MU)
FIRM-E (PT) [61]	3	100	10	770	NA	0.67	683
Effecthandel Vast (SE) [55]	4.5	40	30	6,877	1,581	19 (LF); 65 (MU)	209 (SF); 65 (MU)
Switch Market (SE) [55]	7.5	16	4	2,418	759	NA	444

The results of the maturity assessment indicate that LFM initiatives in EU are generally still at an early stage of development, with many currently operating as research projects, pilot programmes, or demonstration initiatives. Nevertheless, several LFMs, including the UKPN Local Flexibility Market, Marché de Flexibilités Locales, GOPACS, Euroflex, and Switch, have been operational for more than five years. These more mature initiatives can therefore provide valuable practical experience and lessons learned for new LFMs and for system operators considering the procurement of flexibility through LFMs. It should be noted that the maturity level of each initiative is calculated relative to 2026, the reference year of this report.

Among the more mature LFMs, the UKPN Local Flexibility Market provides a relatively high level of publicly available data compared with other initiatives. More broadly, local flexibility plays an established role in distribution-system operation and network planning in the UK, supported by standardized market processes and the systematic consideration of flexibility as an alternative or complement to network reinforcement. Within the UKPN initiative, the available data also show substantial reserved flexibility capacity and activated energy volumes at comparatively moderate prices.

Generally, in terms of products, we see that capacity procurement is a widespread design choice, often combined with energy products. Furthermore, initiatives that use a similar market platform, including Marktflexibilitätsdiensten, Euroflex, Effecthandel Vast, and Switch Market, apply similar flexibility products, namely LongFlex (LF), ShortFlex (SF), and MaxUsage (MU). LongFlex is a longer-term availability product under which an FSP commits to making a specified capacity available within a defined geographical area and during contracted delivery periods. ShortFlex is a short-term activation product through which FSPs offer a specified adjustment in consumption or generation for defined delivery periods, typically as hourly products traded on a day-ahead or intraday basis. ShortFlex can be used independently, allowing flexibility to be offered without a preceding LongFlex contract, or as the mechanism for activating capacity contracted through LongFlex, depending on the design of the individual market. MaxUsage is a longer-term contractual product under which an FSP commits to keeping electricity consumption below an agreed absolute or percentage-based ceiling during specified periods. The remaining LFMs considered in the table are generally operated through local or initiative-specific market arrangements. They use similar products, though with different names. Generally, over all initiatives, it can be seen that when there is capacity procurement, markets remunerate FSPs for their reservation. In most cases, capacity remuneration is combined with energy remuneration, but there are also initiatives that only apply energy remuneration.

To ensure a consistent reference period for comparing flexibility volumes and prices, the indicators presented in Table 33 are calculated for 2025. However, despite the use of a common reporting year, the indicators are not fully harmonized across LFM initiatives. For instance, reserved capacity may refer to requested, qualified, contracted, or awarded capacity, depending on the terminology and data available for each market. Similarly, price indicators may represent average clearing prices, volume-weighted average prices, auction base prices, or values derived from annual availability payments. Accordingly, the results presented in Table 33 should be regarded as indicative measures of LFM activity rather than as fully standardized and directly comparable market statistics.

The reported reserved capacity and activated volume in Table 33 differ substantially across the LFM initiatives. Reserved capacity ranges from relatively small values, such as 15–30 MW in RomeFlex, to much larger values such as 7,952.5 MW in the UKPN Local Flexibility Market and 9,347.364 MW in Euroflex. Activated flexibility volumes are reported for fewer markets, but they also show a broad range, from around 200 MWh in the Flemish market to 14,747.5 MWh in UKPN. In summary, the

results show that some LFM remain relatively small or pilot-oriented, while others have reached a much larger scale in terms of both procured capacity and activated energy.

The results of price indicators in Table 33 also show a wide variation across the assessed LFM initiatives, reflecting differences in market design, product type, local grid needs, and procurement conditions. For reserved flexibility, the reported prices range from very low values such as 0.67 €/MW in FIRM-E to substantially higher values such as 119.3 €/MW in the UKPN Local Flexibility Market. In markets where different products are distinguished, reservation prices also vary by product type, for example 70 €/MW for LF and 150 €/MW for MU in the Flemish market. Activation prices are generally higher, and several markets report them in the range of 200–450 €/MWh, including UKPN, RomeFlex, GOPACS, Effecthandel Vast, and Switch Market. Overall, the results indicate that reservation prices tend to remain lower than activation prices, while activation prices are more sensitive to market scarcity, product characteristics, and the specific flexibility service being procured.

Based on the reported results in Table 33, for LFM initiatives it is concluded:

- Currently, European LFMs cover a broad spectrum of development, ranging from pilot and demonstration projects with limited operational activity to initiatives in which flexibility is procured and activated on a recurring basis. The reported results for initiatives such as UKPN, GOPACS, Marché de Flexibilités Locales, Euroflex, and Switch Market demonstrate that local flexibility is no longer confined to small-scale experimentation and can be used at a substantial operational scale. Yet, many newer initiatives remain in pilot or demonstration phases with limited operational data. As a result, there is currently still **a lot of experimentation with LFMs and it is observed that most initiatives start with a simplified approach, gradually introducing greater complexity. This leads to a lot of heterogeneity in the initiatives.**
- **Differences in definitions, price metrics, reporting periods and data availability substantially limit direct comparison between LFM initiatives.** The observed variation in capacity, activated energy, prices and FSP participation reflects both genuine differences in market maturity and activity and differences in network scope, local grid needs, product design, procurement arrangements and reporting practices. These indicators must therefore be interpreted within the context of each initiative, with FSP numbers providing only a partial indication of liquidity and competition.
- **In terms of product design, advance reservation of flexibility remains common, indicating that system operators value certainty regarding the availability of flexibility in addition to its short-term activation.** Reported reservation prices are generally numerically lower than activation prices; however, these price indicators remunerate different services and are often expressed using different units and time bases. They should therefore be interpreted as complementary components of flexibility procurement rather than directly comparable price levels.

4.8 Fast Frequency Response

4.8.1 Executive summary

Fast Frequency Response (FFR) provides rapid active-power support to limit grid frequency deviations following a power imbalance, particularly during low-inertia conditions. It complements conventional frequency control by responding quickly enough to help maintain frequency within operational limits as fewer synchronous generators remain online during periods of high wind and solar generation.

FFR is implemented in a select number of countries in Europe. No standardised Europe-wide product exists. This section compares the designs of four different FFR mechanisms that are currently operational:

- In **Ireland and Northern Ireland**, delivering a **Secure, Sustainable Electricity System (DS3) Fast Frequency Response**[62],
- In the **Nordic** power system (comprising Norway, Sweden, Finland, and eastern Denmark (DK2)), the common Nordic **Fast Frequency Reserve**[63]·[64]·[65],
- **Great Britain's Dynamic Containment (DC) and Dynamic Moderation (DM)**[66]·[67], and
- **Italy's Fast Reserve**[68]·[69]·[70].

Each delivers automatic active power within one to two seconds. The main differences between these designs are the event addressed, response direction (upward or downward), activation speed, delivery duration and how capacity is selected and paid. Formal eligibility for participation is broad and technology-neutral, but published participation is dominated by battery energy storage systems (BESS). Public sources cover rules and awards in a detailed way, but reporting on delivered performance is limited. This document therefore focuses on comparing market design and market outcomes.

4.8.2 Introduction

FFR refers to rapid active-power responses used to support system frequency following a power imbalance, particularly under low-inertia conditions. TSOs procure such responses through services whose specifications vary between power systems. FFR complements primary frequency control by delivering active-power support more rapidly, helping to arrest post-disturbance frequency excursions and keep frequency within operational limits. In the Nordic synchronous area, Fast Frequency Reserve was introduced to supplement frequency containment reserves for disturbances (FCR-D) during conditions combining low inertia with a large reference incident. Nordic FFR requires full activation within 0.7–1.3 seconds after the specified frequency threshold is crossed [63].

Low-inertia conditions are expected to become more frequent as converter-interfaced wind and solar generation increasingly displaces synchronous generation from operation [63, 64, 65]. High instantaneous wind and solar output, particularly when combined with low demand or substantial imports through high-voltage direct current (HVDC) connections, can leave fewer synchronous generators connected to the system. Consequently, less rotational kinetic energy is available to oppose frequency changes, even where conventional generating capacity remains installed. Following a given power imbalance, lower inertia increases the initial rate of change of frequency and can require faster active-power support to prevent excessive frequency deviations [63, 65]. FFR addresses this need through rapid changes in generation, storage output or demand. It does not itself restore synchronous inertia; instead, it mitigates the consequences of reduced inertia for frequency stability.

4.8.3 Screening of European Fast Frequency Response Candidates

4.8.3.1 Screening methodology

A targeted review of publicly available TSO and regulatory documentation was used to identify European fast frequency response candidates. The screening covered the Nordic countries (Denmark, Finland, Norway and Sweden), Ireland and Northern Ireland, Great Britain, and continental TSOs indicated in Table 34. Technical specifications, procurement arrangements and published development plans were examined for fast frequency response services, including services marketed

under different names. Candidates were assessed against the functional definition below and compared by operational status, response design and procurement arrangement. The resulting classifications and selection decisions are recorded in Table 34. The objective was to identify a limited set of operational use cases spanning different technical and procurement approaches, without claiming an exhaustive inventory of all European FFR-like services. Nonetheless, an effort has been made to perform a Europe-wide screening to maximize the identification of operational FFR-like services.

4.8.3.2 Applied definition of FFR

National and regional names for fast services are not harmonised. This study therefore proposes the following definition to distinguish fast frequency response services from ordinary balancing services: **to be considered fast frequency response, a service must provide automatic active-power containment from locally measured frequency, be separately specified and additional to or materially faster than ordinary frequency containment, normally reach full response within about two seconds, and address a severe or rapidly developing frequency deviation.**

4.8.3.3 Selection of relevant FFR case studies

Table 34 provides an overview of identified FFR-like candidates for further study, along with their classification and selection decision.

In scope (selected)

Nordic and DS3 FFR as well as Italy's Fast Reserve are included in the study's scope. Also, Great Britain's DC and DM are included as functional one-second equivalents. Note that no uniform naming convention exists for similar FFR-like services across countries.

Out of scope (not selected)

Nordic dynamic FFR is not yet operational. Great Britain's ten-second Dynamic Regulation (DR) is considered more similar to the ordinary frequency containment reserve product and is not retained. The screened Baltic emergency capabilities and ordinary continental reserve suites are not separately procured FFR products. TSOC, the TSO of Cyprus, mentions its FFR product ETARS (ETAPΣ) in its Operating Margin Policy [71]. However, product response parameters seem to be indicative values rather than verified characteristics of an operating contract. Moreover, documents are only available in Greek and are therefore difficult to investigate. ETARS is hence not considered for further study in this report.

Ordinary FCR, aFRR and mFRR, inertia and grid-forming services, emergency controls without separate procurement, and slower balancing services are also outside the scope of this study (not explicitly listed in the table).

Table 34: Screened fast frequency response candidates

Country	Product or service	Functional classification	Operational status	Response design	Procurement arrangement	Screening outcome
Norway, Sweden, Finland and eastern Denmark	Nordic FFR	Dedicated FFR	Operational	Upward; 0.7-1.3 s alternatives	Common technical product; national call-off	✓ Selected
Ireland and Northern Ireland	DS3 FFR	Dedicated FFR	Operational under regulated arrangements; DASSA ¹⁰ approved	Static/dynamic; ≤2 s, faster rewarded	Periodic contract gates and regulated tariffs; DASSA ¹⁰ target May 2027	✓ Selected
Great Britain	DC + DM	Close functional equivalents to FFR	Operational	Separate post-fault and preventive 1 s curves	Daily uniform-price auction	✓ Selected
Italy	Fast Reserve	Dedicated FFR	Operational five-year contracts through 2027; TIDE ¹¹ residual route enabled	Symmetric; ≤1 s	Five-year pay-as-bid contracts; TIDE ¹¹ residual auction route	✓ Selected

¹⁰ DASSA = Day-Ahead System Services Auction, a market-based procurement mechanism designed to replace DS3's fixed-tariff system

¹¹ TIDE = Testo Integrato del Dispacciamento Elettrico, Italy's regulatory framework for electricity dispatching

Country	Product or service	Functional classification	Operational status	Response design	Procurement arrangement	Screening outcome
Cyprus	ETARS (a fast-response frequency regulation reserve)	Dedicated FFR	Technical and procurement framework established [72]; operational procurement not able to be verified	Upward/downward provision envisaged; indicative upward design: 0.8 s activation	Mandatory reservation and additional daily auctions; remuneration linked to FCR prices with markup [71]	X Not selected
Nordic region (Norway, Sweden, Finland and eastern Denmark)	Nordic dynamic FFR	Dedicated FFR variant	Technical concept; not operational	Proportional/dynamic concept	No approved market design	X Not selected
Great Britain	DR	Frequency containment reserve	Operational	10 s frequency-containment response	Same auction platform	X Not selected
Estonia, Latvia, Lithuania	Baltic fast capability	Emergency capability	No dedicated product located	High-voltage direct-current (HVDC) interconnector and BESS emergency response	No near-term FFR procurement found	X Not selected

Sources: EirGrid & SONI [62], Nordic TSOs [63, 64, 65] Fingrid [73], National Energy System Operator [14, 15, 74], Terna [68, 69], ARERA [75 [76, 77], European Commission [78], TSOC [71]

4.8.4 Product characteristics

Table 35 shows that products have similar response speeds but have other important differences.

- DS3 and Nordic FFR mainly limit the under-frequency deviation with upward reserve. Great Britain separates preventive DM from post-fault DC and procures both response directions. Italy procures one symmetric product.
- Delivery duration ranges from 10 seconds for DS3 to 15 or 30 minutes for energy-limited Great Britain providers.
- Withdrawal and recovery are also controlled by the service definition: providers must avoid a second imbalance when fast response ends and slower reserves take over.
- All four products admit a wide range of resource types, although the fast control, metering and energy-management duties currently favour batteries.

The trigger, direction, speed, duration and recovery are typically dimensioned based on the credible disturbance, maximum frequency deviation risk, ordinary-containment trajectory, time to replacement reserves and acceptable rebound.

Table 35: Technical product characteristics

Region / Country	Product	Frequency security role	Direction	Activation trigger	Response time	Delivery duration	Recovery	Eligible resources
Ireland region	FFR	Rapid containment when system experiences severe frequency deviation.	Upward (protocol also allows downward procurement)	Dynamic response between 49.80 and 49.985 Hz; static response between 49.3 and 49.8 Hz.	≤ 2 s; higher remuneration for faster response	10 s	Response energy before T+10 seconds must compensate any response-energy shortfall from T+10 to 20 seconds after the event.	Storage, demand response and aggregators, wind, solar, conventional generation units and interconnectors
Nordic region (Norway, Sweden, Finland and eastern Denmark)	FFR	Rapid containment when risk that the post-disturbance frequency falls below 49.0 Hz.	Upward	Three possible triggers: 49.7 Hz 49.6 Hz 49.5 Hz	1.3 s at 49.7 Hz 1.0 s at 49.6 Hz 0.7 s at 49.5 Hz	30 seconds, or 5 seconds with controlled deactivation	Controlled deactivation obligatory. Full response capability must be restored within 15 minutes.	Generation, storage and demand response. Aggregation allowed.
Great Britain region	DC	Post-fault containment after a large generation or interconnect or loss	Separate upward and downward products	Locally measured frequency follows the contracted post-fault response curve, reaching full response at 0.5 Hz from nominal frequency	Response begins within 0.5 seconds, full delivery within 1 second	15 minutes	Active stored-energy management to ensure contracted response remains deliverable throughout the four-hour block	Generation, demand response and storage, including aggregation. Minimum 1 MW.

	DM	Preventive fast moderation when frequency approaches the operational limit	Separate upward and downward products	Locally measured frequency follows the preventive response curve, reaching full response at 0.2 Hz from nominal frequency	Response begins within 0.5 seconds, full delivery within 1 second	30 minutes	Active stored-energy management to ensure contracted response remains deliverable throughout the four-hour block	Generation, demand response and storage, including aggregation. Minimum 1 MW.
Italy	Fast Reserve	Rapid containment when declining synchronous inertia makes ordinary containment too slow.	Symmetric upward and downward response.	Frequency-response curve configured by Terna dependent on system conditions	Response begins within 300 milliseconds; full response within 1 second.	30 s between the two configured thresholds, 15 min beyond severe-deviation threshold	Default 200 seconds recovery when frequency within deadband; configurable by Terna between 0-300 seconds. Energy-limited units must restore their 15-minute energy capability gradually.	Storage, generation, demand response and aggregation. Fast Reserve Unit: 5 MW minimum and 25 MW maximum within one area.

Sources: EirGrid & SONI [62, 79], D1-D2, Nordic TSO [63, 64, 65], National Energy System Operator [66,67], Terna [69,70].

4.8.5 Procurement, remuneration and resource participation

Table 36 shows the procurement of FFR reserve capacity, the actual reservation/scheduling of the procured FFR reserves, and the remuneration mechanisms for the selected fast frequency response products. Notice that the Nordic case combines one common regional security calculation with different national procurement rules. This means that countries of the Nordic region jointly define common technical FFR requirements (such as frequency threshold, response time, and activation duration) and the size the FFR reserves to be procured for their synchronous area as a whole. However, the actual operational procurement, scheduling/activation and remuneration of FFR reserves happen on the country level. To this end, Table 36 splits out the Nordic region into its 4 constituents: Norway, Sweden, Finland, and eastern Denmark.

Procurement frequency and time horizon

Italy performed one single 5-year auction, Sweden and Norway perform annual procurements of reserve capacity, (Northern) Ireland performs six-monthly procurements and Finland, eastern Denmark (DK2), and Great Britain perform daily auctions.

Reservation / scheduling frequency

Some countries schedule the required availability of the reserved capacities upon procurement / auction completion. Other countries only communicate reservation schedules in a second instance and closer to delivery, after the procurement of FFR capacities has already occurred.

1. **Simultaneous procurement and reservation:** in (Northern) Ireland, Finland, eastern Denmark (DK2) and Great Britain, procured capacity is also immediately reserved. Ireland admits providers through six-monthly contract gates and pays available capability in each trading period. Great Britain, Finland and Eastern Denmark buy and reserve capacity simultaneously one day ahead, although at different granularities (four-hour blocks in Great-Britain versus one-hour blocks in Finland and DK2).
2. **Separate procurement and reservation:** reservation happens separately for Sweden, Norway and Italy. Sweden selects an annual pool, then reserves hours on Monday for Tuesday-Friday and on Friday for Saturday-Monday. Norway's "FFR Profile" fixes availability hours (hours with low-inertia) seasonally, while it's "FFR Flex" availability requirements are ordered weekly, with supplementary orders possible by 15:00 one day ahead. Italy auctioned five-year contracts in 2020 for delivery in 2023-2027 and schedules 1,000 availability hours per year, first at D-7 and finally at D-2.

Remuneration

FFR is mainly remunerated for reserved capacity because activation is rare and normally involves little net energy activations. Norway and Italy compensate activated energy costs separately from capacity reservation.

Additional reflections

The procurement horizon determines who carries forecast and revenue risk. Day-ahead procurement can follow the changing low-inertia requirement and avoid paying for high-inertia hours, but providers face less revenue certainty. Long-term contracts such as in Italy can support new investment, but risk under-delivery in case of project delays and require a residual short-term procurement option if significant awarded FFR capacity is not built in time (Italy officially foresees such an option but did not use it in practice yet).

Table 36: Procurement, reservation and remuneration characteristics

Market	Procurement frequency	Procurement time horizon	Time granularity	Min bid size	Reservation / scheduling frequency	Remuneration
Ireland / Northern Ireland	Six-monthly	Six months	Six months	N/A: no volume auction	Six-monthly	EUR 1.94/MW/h base x six scalars
Sweden (part of Nordic region)	Annual	1 year	Hourly	0.5 MW	Twice-weekly	Pay-as-cleared
Norway (part of Nordic region)	Annual	1 year	Seasonal profiles	Profile 1 MW; Flex 5 MW	Profile fixed; Flex weekly, with D-1 top-up	Pay-as-cleared; activation costs separate
Finland (part of Nordic region)	Day-ahead	1 day	Hourly	1 MW	Day-ahead	Pay-as-cleared
DK2 (eastern Denmark, part of Nordic region)	Day-ahead	1 day	Hourly	0.3 MW	Day-ahead	Pay-as-cleared; regulated price if one enterprise
Great Britain	Day-ahead	1 day	Four-hour blocks	1 MW	Day-ahead	Pay-as-cleared by product
Italy	One auction	5 years	1,000 h/year	5 MW min.; 25 MW max. per FRU	Preliminary D-7; final D-2	Pay-as-bid; 80,000 EUR/MW/year ceiling

Sources: Eirgrid & SONI [62], SONI [80], Svenska kraftnat [81, [82], Statnett[83], Fingrid[84], Energinet[85, 86], National Energy System Operator[74, 87], Terna[69, 88], ARERA [77.]

4.8.6 Flexible resources: requirements, eligibility and observed participation

Table 37: Eligibility and observed participation of technologies in the FFR products

Market	1. Technical / prequalification requirements	2. Legally or technically eligible technologies	3. Observed participation
DS3 (Ireland / Northern Ireland)	≤ 2 s curve; 20 ms sampling; T+10 trajectory and T+20 anti-rebound tests; site control and staggered recovery	Generation, storage, demand/aggregators, wind, solar and interconnectors	Gate 13 contracts include aggregators, solar and wind ; current MW shares by technology not public.
Nordic	Three trigger/time options; ≥ 10 Hz logs; sustain/deactivation test; national entry rules	Production, consumption, storage and aggregated groups	Prequalified in Sweden: 960 MW storage , 90 MW demand , 50 MW wind + storage ; Finland: 410/34/17 MW storage / consumption / multi-technology aggregation .
Great Britain	1 s curves; 20 Hz tests/data; 1 MW unit; DC 15 min and DM 30 min energy	Generation, demand and storage; aggregation within one GSP Group	Batteries supplied 96.6-98.5% of awarded DC/DM capacity-hours; constituent assets and delivery not public
Italy	Symmetric ≤ 1 s; 5-25 MW FRU; 15 min energy each way; constituent metering/control; annual retest	Storage, generation, non-interruptible demand and aggregation within one area	Operating portfolio described as electrochemical BESS ; operating MW by technology/aggregation not public

Sources: EirGrid & SONI [62, 79], EirGrid[89], Nordic TSOs [63], Svenska kraftnat [90], Fingrid[91], National Energy System Operator[67, 92], Terna[69, 70, 93].

Table 37 summarises the eligibility and observed participation of technologies in the FFR products. Many types of resources (e.g. renewable generation, storage, demand response, aggregation) may formally provide FFR services, but in reality batteries seem to provide most of the fast response capacity. Batteries supplied 96.6-98.5% of Great Britain's awarded DC and DM capacity-hours, dominate the Swedish and Finnish qualified pools, and make up Italy's reported operating portfolio. DS3 contracts include aggregators, solar and wind, but MW shares by technology are not public. The pattern suggests that sub-second control, accurate tracking and stored-energy management currently favour batteries. High data rates, site controls and minimum unit sizes also create fixed participation costs, so aggregation remains important for smaller demand and distributed resources.

4.8.7 Market outcomes

Table 38 provides prequalified (i.e., technically eligible to participate in auction), contracted (i.e., selected in auction), scheduled (i.e., assigned a time schedule during which to be available) and available (i.e., operating and ready to respond) capacity. Capacities seem to differ greatly between prequalification, contracting and delivery stages. Sweden reports about 1,100 MW prequalified, 132 MW contracted in its framework and at most 110.2 MW activated. Finland reports 461 MW prequalified and at most 70.8 MW contracted. Italy reports 1,327.3 MW qualified and offered, 249.9 MW awarded and about 170 MW operating.

Ireland and Great Britain procure much larger volumes, possibly because their requirements are larger and, for Ireland, because the current contract process has no ex-ante volume cap.

Price differences reflect contract and product obligations. Italy's EUR 29.50/MW/h equivalent covers a five-year pay-as-bid contract and 1,000 selected hours each year. Those investment and commitment terms may contribute to the price, as qualified supply was almost six times the auction target and the average award was near one third of the price ceiling, indicating strong competition. Norway's "FFR Flex" providers may command more than "FFR Profile" providers because it covers less predictable hours and preserves optional capacity. In Great Britain, the price for upward dynamic moderation (Dynamic Moderation Low, or DML) was positive and highest while that of downward dynamic moderation (Dynamic Moderation High, or DMH) was negative, showing that procured activation directions impact prices. DCH (Dynamic Containment High) and DCL (Dynamic Containment Low) show similar but smaller price differences. DS3's EUR 1.94/MW/h is only a base rate: no public average of the six applied scalars exists. For example, high-inertia-scarcity and fast-response scalars alone can multiply the base by 10.5 to EUR 20.37/MW/h before application of the other scalars.

Table 39 shows quality assurance, consequences and published realised outcomes. Every studied market tests the delivered response and applies payment reductions or sanctions accordingly. No market publishes reports on availability versus schedule, response errors and penalties. Italy reports ~170 MW operating versus ~250 MW reserved reserves, but does not report actual response quality apart from qualitative network benefits.

Table 38: Prices and volumes by procurement stage¹²

Market	Period	Prequalified	Contracted	Scheduled	Available	Prices
DS3 (Ireland / Northern Ireland)	Gate 13, 1 Oct 2025	Not identified	1,954 MW - Ireland 1,573 MW - Northern Ireland 381 MW	← Same as contracted	Not public / not identified	1.94 €/MW/h base price, multiplied by six scalars
Sweden	2026 procurement	~1,100 MW	132 MW.	36 MW average over 1,169 active hours; 107.80 MW maximum (through 24 Aug 2026)	Not public / not identified	~17.88 €/MW/h (198.25 SEK/MW/h volume-weighted)
Norway	2026 seasonal results	Not identified	Profile: 54.5 MW for 1,210 scheduled hours. Flex: 91.4 MW for 300 ordered hours per accepted bid.	Profile: ← Same as contracted. Flex: not public / not identified; determined by weekly and day-ahead scheduling	Not public / not identified	Profile: about 11.05 €/MW/h (120 NOK) Flex: about 50.55 €/MW/h (549 NOK)
Finland	Through 28 Aug 2026	461 MW	20.84 MW average over 1,239 active hours; 70.8 MW maximum	← Same as contracted	Not public / not identified	11.40 €/MW/h volume-weighted.
DK2 (eastern Denmark)	Through 28 Aug 2026	Not identified	3.56 MW average over 1,212 active hours; 9.25 MW maximum	← Same as contracted	Not public / not identified	37.83 €/MW/h volume-weighted.

¹² Indicative euro conversions use European Central Bank reference rates on 28 August 2026: EUR 1 = GBP 0.85720, SEK 11.0885 and NOK 10.8595. Italy's hourly figure divides its weighted annual award by 1,000 scheduled hours.

Market	Period	Prequalified	Contracted	Scheduled	Available	Prices
Great Britain	1 Jan-28 Aug 2026	Not public	Mean awarded: • DCH 1,186.1 MW • DCL 1,189.3 MW • DMH 540.2 MW • DML 511.7 MW	← Same as contracted	Not public / not identified	Accepted prices (converted): • DCH 2.04 €/MW/h • DCL 3.25 €/MW/h • DMH - 0.47 €/MW/h • DML 7.70 €/MW/h
Italy	Contracts: 1 Jan 2023-31 Dec 2027	1,327.3 MW	249.9 MW	Not public / not identified; determined by D-2 scheduling	~170 MW operating end 2025	Average ~29.50 €/MW/h across 1,000 h/y

Sources: EirGrid & SONI[94] [95], SONI[96], Fingrid [91, 97, 98], Svenska kraftnet [81, 82, 90, 99], Statnett [83], Energinet [86], National Energy System Operator [92], Terna [88, 93], European Central Bank[100].

Table 39: Quality assurance, consequences and published realised outcomes

Market	Assurance metric and financial consequence	Published realised outcome
DS3 (Ireland / Northern Ireland)	20 ms sampling; measurement-device operability $\geq 98\%$; every-sample trajectory to T+10 and anti-rebound energy test to T+20. Failures reduce the monthly performance scalar for up to five later months.	No public aggregate/unit pass rates, trajectories, resource availability, activations or applied penalties.
Nordic	≥ 10 Hz logs and common response test. Sweden requires $\geq 85\%$ pre-call and 100% post-call availability; pre-call shortfall is unavailable MW x marginal price x 1.25, while post-call failure may require repayment plus 50%. Finland charges 3 x the hourly price; DK2 may recover replacement cost; Norway can reduce payment or sanction.	No harmonised outcome dataset. DK2's rounded 0% 2025 load factor indicates negligible activation but not compliance.
GB	20 Hz data; error $\leq 3\%$ earns full credit and 3-7% declines to zero; worst half-hour K-factor applies to the four-hour block. Availability factor becomes zero at ≥ 1.8 s unavailable in a 30-min period. With zero availability/performance, settlement is zero when price $\geq$ GBP 1/MW/h and negative when price is below that adjustment floor.	Unit-level K-factors, settlement deductions, response trajectories and activation success are not public.
Italy	Initial and annual tests; ≤ 1 s response; steady-state tolerance is the smaller of 5% assigned MW and 1 MW. Non-availability or non-compliance reduces remuneration or creates charges.	Terna reports qualitative grid benefit; no public event counts, pass rates, shortfalls or realised penalties.

Sources: EirGrid & SONI [62, 79], Nordic TSOs [63], Energinet[101], National Energy System Operator [87], Terna [70, 102].

4.8.8 Synthesis of key findings

The comparison shows that European FFR provision follows distinct national and regional approaches, with no standardised Europe-wide product. Italy is the only selected operational case within Continental Europe; the other cases concern smaller synchronous systems, consistent with the report's emphasis on inertia and disturbance size relative to the system. Although all selected services deliver full response within approximately two seconds, they differ substantially in activation triggers, response direction, duration, recovery and coordination with slower reserves.

Procurement ranges from day-ahead auctions to multi-year contracts, reflecting different trade-offs between matching changing system needs and providing investment certainty. Remuneration primarily rewards reserved capacity and not activated energy. Batteries seem to dominate reported participation despite theoretically broad technology eligibility. Differences between qualified, contracted and operating capacity, together with limited public reporting on delivered performance, constrain comparisons of effectiveness; prices likewise require interpretation against product and contractual obligations. These findings provide the basis for the following outlook and implementation lessons, highlighting the importance of system-specific design, procurement arrangements and verifiable delivery.

4.8.9 Outlook for broader European deployment

The near-term outlook for European FFR deployment points toward further refinement in the countries that already use fast services. The development of one Europe-wide FFR product does not seem to be currently on the table. Northern Ireland targets day-ahead procurement in May 2027 [103]. Sweden targets an hourly day-ahead FFR market in 2028 [81]. Great Britain targets a real-time supplement in early 2027, while its 30-minute and locational reforms remain separate workstreams. Italy's pilot contracts continue through 2027, and TIDE allows Terna to procure any residual ultra-fast requirement. Dynamic Nordic FFR remains a technical concept.

Broader deployment is most likely in small or islanded synchronous systems, or in general where the loss of one large generator or high-voltage direct-current interconnector is large relative to demand and low inertia makes ordinary containment too slow. A large interconnected system like continental Europe may instead adapt ordinary FCR procurement, procure inertia or grid-forming capability, or limit the largest credible loss.

4.8.10 Transferable implementation lessons

The four studied cases suggest the following preliminary FFR implementation considerations. Given the limited sample and incomplete reporting on delivered performance, these should be assessed against local system conditions rather than treated as universally applicable recommendations.

1. **Base procurement on an assessed system need.** The Nordic approach links FFR requirements to forecast inertia, the largest reference incident and ordinary frequency containment. A similar assessment could help determine whether a dedicated FFR product is warranted. Where relevant, this assessment could also compare FFR with adapting ordinary containment, procuring inertia or grid-forming capability, or limiting the largest credible loss; the present comparison does not establish their relative cost-effectiveness.
2. **Specify response duration, withdrawal and recovery alongside activation speed.** The reviewed products differ in their activation thresholds, response direction, delivery duration and recovery requirements. Nordic controlled deactivation and Ireland anti-rebound

requirements illustrate the importance of how the response ends. Specifications should therefore address these characteristics together, considering the local disturbance and the contribution of slower reserves, to limit the risk of a further imbalance when FFR is withdrawn.

3. **Assess procurement and scheduling arrangements against total reservation cost.** Qualification, contracting and scheduling should be distinguished when assessing how much capacity is required and paid for. Procurement options should be compared through the combined effect of reserved capacity, scheduled hours and prices, subject to meeting the same security and delivery requirements. Shorter procurement horizons could improve alignment with updated forecasts, while longer contracts could support investment and revenue certainty. Longer contracts can also be combined with scheduling closer to delivery, as illustrated by Italy. Table 39 does not establish that either approach consistently provides the required reserves at lower total reservation and activation cost.
4. **Consider aggregation to support participation and technology neutrality.** Allowing smaller demand, storage and mixed portfolios to meet minimum bid sizes through aggregation could broaden participation, support technology neutrality and strengthen competition. Entry and metering requirements should remain proportionate while providing sufficient evidence that participants can meet the specified response. Broad eligibility alone does not ensure diverse participation, as the reported portfolios remain predominantly battery-based.
5. **Monitor project delivery under long-term procurement.** Italy's approximately 170 MW operating against 249.9 MW awarded illustrates a potential gap between contracted capacity and operational readiness. Where long-term procurement relies on projects becoming operational, monitoring development milestones and considering arrangements for replacing unavailable capacity could help manage delivery risk.
6. **Publish performance indicators.** Where practically feasible, publishing capacity at successive prequalification, procurement, and scheduling stages, availability, response quality, non-delivery and penalties would be a useful transparency measure. Publishing prices and explaining remuneration adjustments alongside these indicators could help market participants assess the performance expected relative to the remuneration offered. Such reporting would not directly or immediately improve FFR design, but supports transparency and thereby market actors' willingness to participate and hence competitiveness.

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