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AHEAD

AI-informed Holistic Electric Vehicles Integration Approaches for Distribution Grids

D4.1

# Grid planning strategies

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# EXECUTIVE SUMMARY

As the energy system undergoes rapid transformation driven by decarbonization, electrification, and digitalization, traditional planning approaches are increasingly challenged by the need for flexibility, coordination, and resilience. The present deliverable presents a comprehensive analysis of evolving grid planning methodologies on distributed energy resources into transmission and distribution grids, with a focus on the latter.

This document outlines the limitations of conventional deterministic planning and introduces advanced methodologies such as scenario-based probabilistic planning, hosting capacity analysis, and locational value assessments. It emphasizes the importance of aligning transmission and distribution planning, modernizing interconnection processes, and leveraging digital tools to support dynamic system reconfiguration and real-time decision-making.

The transformation of the electricity grids requires a shift towards more coordinated, data-driven, and resilient planning approaches, and to ensure long-term system reliability and efficiency, a phased implementation strategy is advised: 1) reinforce physical infrastructure and deploy digital monitoring tools; 2) Develop market and regulatory frameworks to enable DER participation; 3) Align organizational structures and policy objectives for transparency and adaptability.

A key contribution of this deliverable is the definition of representative EV charging case studies, which serve as foundational inputs for subsequent tasks, including simulation and validation, and tool development. These cases reflect diverse grid conditions and charging behaviours, enabling targeted analysis of grid impacts and flexibility opportunities.

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| | |
|---|---|
| AC | Alternate Current |
| ADMS | Advanced Distribution Management System |
| ADS | Active Distribution System |
| ALPEX | Albanian Power Exchange |
| AMI | Advanced Metering Infrastructure |
| ARERA | Autorità di Regolazione per Energia Reti e Ambiente |
| ASIG | Autoriteti Shtetëror për Informacionin Gjeohapësinor |
| B/C | Benefit/ Cost ratio |
| BAA | Balancing Authority Areas |
| BESS | Battery Energy Storage System |
| CHP | Combined Heat and Power |
| CIGRE | Conseil International des Grands Réseaux Électriques |
| DBSCAN | Density-Based Spatial Clustering of Applications with Noise |
| DC | Direct Current |
| DER | Distributed Energy Resource |
| DG | Distributed Generation |
| DigSILENT | DIgital SImuLation and Electrical NeTwork calculation program |
| DO | Distribution Operator |
| DSI | Demand Side Integration |
| DSO | Distribution System Operator |
| DVR | Dynamic Voltage Restorer |
| EBRD | European Bank for Reconstruction and Development |
| EIMV | Elektroinštitut Milan Vidmar |
| ELES | Elektro-Slovenija |
| ENS | Energy Not Supplied |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| ERE | Enti Rregullator i Energjisë |
| ERSE | Entidade Reguladora dos Serviços Energéticos |
| ETap | Electrical Transient Analyzer Program |
| EU | European Union |
| EV | Electric Vehicle |
| EVSE | Electric Vehicle Supply Equipment |
| FIRMe | Flexibilidade Integrada em Regime de Mercado |
| GIS | Geographic Information System |
| HV | High-Voltage |
| HVDC | High Voltage Direct Current |
| HVDC | High Voltage Alternate Current |
| Interplan | INTEgrated opeRation PLAnning tool towards the pan-European Network |
| IPSA | Interactive Power System Analysis |
| IRR | Internal Rate of Return |
| IT | Information Technology |
| KfW | Kreditanstalt für Wiederaufbau |
| KPI | Key Performance Index |
| LDA | Load Distribution Area |

| | |
|---|---|
| LUP | Langsigtet Udviklingsplan |
| LV | Low-Voltage |
| MASE | Ministero dell'Ambiente e della Sicurezza energetica |
| MATLAB | MATrix LABoratory |
| MCS | Monte Carlo Simulation |
| MV | Medium-Voltage |
| NDP | Network Development Plan |
| NECP | National Energy and Climate Plan |
| NEPLAN | Network Planning |
| NEPN | Integrated National Energy and Climate Plan |
| NPV | Net Present Value |
| NTG | National Transmission Grid |
| OLTC | On-Load Tap Changer |
| OpenDSS | Open-source Distribution System Simulator |
| OSHEE | Operatori i Shpërndarjes së Energjisë Elektrike |
| OST | Operatori i Sistemit të Transmetimit |
| PCB | Printed Circuit Board |
| PDIRT-E | Plano de Desenvolvimento e Investimento da Rede de Transporte de Eletricidade |
| PLF | Probabilistic Load Flow |
| PNEC | Plano Nacional de Energia e Clima 2030 |
| PSCAD | Power Systems Computer-Aided Design |
| PSS SINCAL | Power System Simulator Siemens Network Calculation |
| PSS/E | Power System Simulator for Engineering |
| PSS-ADEPT | Power System Simulation – Analysis, Design, and Evaluation of Power Transmission |
| PV | Photovoltaic |
| REN | Rede Elétrica Nacional |
| RES | Renewable |
| REZ | Renewable Energy Zones |
| RNC | Roteiro para a Neutralidade Carbónica |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCADA | Supervisory Control And Data Acquisition |
| SODO | Sistemski operater distribucijskega omrežja z električno energijo |
| SST | Solid-State Transformer |
| S-STATCOMs | Static Synchronous Compensator |
| SVC | Static VAR Compensator |
| SWOT | Strengths, Weaknesses, Opportunities, and Threats |
| TIQD | Testo Integrato della regolazione |
| TOTEX | Total Expenditure |
| TRI | Total Return Index |
| TSO | Transmission System Operator |
| UK | United Kingdom |
| USA | United States of America |
| V2X | Vehicle-To-Everything |
| VAR | Volt-Ampere Reactive |
| WG | Working Group |

# 1. INTRODUCTION

## 1.1. Scope and Objectives

The purpose of this deliverable is to provide a comprehensive analysis of current and emerging planning methodologies, with a particular focus on the challenges and opportunities with a large-scale integration of flexibility assets, such as EVs.

This deliverable addresses the evolving role of grid planning in a rapidly changing energy landscape. Traditional planning approaches are characterised by deterministic methods, centralized generation assumptions, and passive load growth projections. This approach is increasingly inadequate in the face of rising uncertainty, bidirectional power flows and the need of flexibility. The deliverable 4.1- Grid Planning Strategies contributes to bridge this gap by identifying and evaluating planning strategies that are robust, adaptive, and aligned with the principles of resilience, cost-effectiveness and sustainability. The scope includes:

- A critical review of existing grid planning methodologies for both transmission and distribution systems, highlighting their historical evolution, current practices, and limitations in the context of DER and EV integration.
- An in-depth analysis of how flexibility, across technical, operational, supply-side, demand-side, and storage dimensions, can be embedded into planning frameworks to enhance grid performance and defer costly infrastructure upgrades.
- A comparative assessment of country-specific planning practices across different geographies in Europe (present in the AHEAD project), identifying best practices, regulatory innovations, and transferable lessons.
- A structured classification of real-world case studies that reflect diverse EV charging scenarios, grid conditions, and planning challenges, serving as a foundation for simulation-based validation in subsequent project tasks.

By following these contributions, this deliverable aims to equip grid planners, regulators, and stakeholders with the knowledge and tools necessary for a new generation of planning practices that are proactive, data-driven, and capable of supporting a flexible electrical grid.

## 1.2. Structure

This document is organized in four main chapters, each building upon foundational concepts through practical methodologies and recommendations:

**Chapter 1 – Introduction** outlines the scope, objectives, and structure and clarifies the relationship between this document and other deliverables within the AHEAD project, ensuring consistency and alignment across work packages.

**Chapter 2 – Review of existing grid planning methodologies** provides a comprehensive review of traditional and evolving grid planning practices for both transmission and distribution systems. It examines the historical context, key planning principles, and the shift toward flexibility-oriented approaches. The chapter also includes a comparative analysis of country-specific planning frameworks across several participating project partner countries, highlighting regulatory innovations, technical practices, and lessons learned.

**Chapter 3 – Grid Capacity Optimization** introduces a classification of real-world case studies that reflect diverse EV charging scenarios and grid conditions. The chapter also presents a dual-ranking methodology to assess the severity of constraints and the effectiveness of solutions and current tools available in the market.

**Chapter 4 – Conclusions and Recommendations** synthesizes the key findings of the deliverable and offers strategic recommendations for grid planners, regulators, and policymakers. It emphasizes the importance of probabilistic planning, TSO-DSO coordination, digitalization, and regulatory innovation.

## 1.3. Relationship with other deliverables

The deliverable 4.1 is a knowledge-based document that it is closely interlinked with several other deliverables and work packages, both upstream and downstream. For upstream dependencies, D1.1 – Usage and Charging Patterns Analysis and D1.2 – End-User Flexibility Solutions provide an overview of current and projected EV usage behaviours, charging profiles and technology barriers. These insights were used as assumptions and boundary conditions in D4.1 to assess grid planning needs and flexibility potential. Also, D1.3 – Regulatory Landscape Analysis contributes to understanding the policy and regulatory context in which grid planning strategies must operate, particularly regarding flexibility services and EV integration. Downstream-wise, D4.2 – EVSEs Use Classification and KPIs and D4.4 – Hosting Capacity Spatial Mapping Models are direct continuous work from D4.1. These tasks operationalize the planning strategies by defining performance indicators and spatial decision-support tools. One of the tasks that will use most of the work defined in D4.1 is D4.3 – Grid Models and Flexibility Validation in Planning Tools that will use the methodologies developed to validate grid models and simulate the impact of flexibility services in real-world scenarios.

# 2. REVIEW OF EXISTING GRID PLANNING METHODOLOGIES

## 2.1. Overview of traditional distribution and transmission grid planning approaches

Grid planning is a vital and complex process in the power system industry covering both transmission and distribution systems, which main goal is to ensure reliable, efficient, and cost-effective power delivery from generation to end consumers. Traditionally, the planning approaches for transmission and distribution grids have been separated and have had distinct characteristics due to their different roles in the power system (Table 1). Nevertheless, both typically rely on deterministic planning methods, which assume worst-case scenarios rather than adopting probabilistic approaches. Cost-benefit analysis is also a key analysis, where planners assess the financial viability of proposed grid investments. Additionally, both domains took load growth assumptions as a key role in guiding decisions, with planners projecting future demand to guide grid development.

**Table 1 – Overview of TSO and DSO responsibilities across grid operations, market functions, and infrastructure planning**

| Role | TSO | DSO |
|---|---|---|
| Balance supply and demand | Balances for its area, including net load of all load distribution areas (LDA) and interchanges with adjacent balancing authority areas (BAA). It ensures system-wide stability and reliability. | The distribution operator does not balance the system but delivers energy to and from the TSO-DSO interface. It may support local balancing with DER. |
| Maintain frequency | Supports frequency control for its system and regional interconnections, coordinating with other balancing authorities. | The distribution operator does not maintain frequency but may provide local frequency support via DER, demand response, or battery storage. |
| Grid scheduling and coordination | Responsible for scheduling and coordinating energy transactions across its area, ensuring optimal power flow and congestion management. | A growing role for DSOs as DER increase, requiring advanced coordination with TSOs and market participants. |
| Open access service | All TSOs provide open access transmission services under federal or national regulations, ensuring fair access to the transmission grid. | Limited open access frameworks exist at the distribution level. However, emerging regulatory frameworks may require open access distribution grids for DER and flexibility services. |
| Operate spot market | Independent system operators (ISOs) and regional transmission organizations (RTOs) clears the wholesale spot market | No spot market clearing at the distribution level. The distribution operator only facilitates energy |

| Role | TSO | DSO |
| --- | --- | --- |
| | for residual energy, ensuring competitive electricity pricing. Spot markets may not exist in vertically integrated utilities. | delivery from wholesale markets to customers and DER providers. |
| Infrastructure planning | Develops long-term transmission plans, working with participating transmission owners (PTOs) to maintain and expand grid infrastructure based on demand growth and renewable integration. | Plans distribution system upgrades, including asset replacements and reinforcements to accommodate DER integration, electrification trends, and resilience improvements. |
| DER integration | Manages DER interconnection requests for large generators and DER that inject energy into the grid, ensuring compliance with grid codes and system stability requirements. | DSOs facilitate interconnections for DER at lower voltage levels and ensure compliance with regulatory procedures. Some DSOs also manage region-level interconnection processes. |
| Voltage control | Manages high-voltage stability across the transmission network through reactive power compensation, capacitor banks, and coordination with generators. | Responsible for medium- and low-voltage grid stability, using on-load tap changers (OLTCs), voltage regulators, and local reactive power management. |

Transmission grid planning traditionally focuses on high-voltage bulk power transfer over long distances. According to Kirschen and Strbac [1], key aspects of traditional transmission planning include:

- **Long-term horizon:** Transmission planning typically considers 10–20-year timeframes due to the very significant lead times and costs associated with major transmission projects.
- **Reliability-driven:** The primary objective is often to maintain system reliability under various contingencies, as outlined in N-1 or N-2 reliability criteria.
- **Power flow analysis:** Planners use AC power flow studies to assess the grid's ability to handle projected loads and generation patterns.
- **Economic considerations:** While reliability is essential, planners also assess the economic benefits of new transmission lines, such as reduced congestion and improved market efficiency.
- **Interconnection studies**: Transmission planning involves examining the impact of new generation interconnections on system stability and security.

Similarly, traditional distribution grid planning is centred around meeting peak demand while maintaining system reliability and minimizing costs. The electrical distribution system was originally planned and designed for the only purpose of delivering electricity to customers from a small number of large powerplants, with power flowing in only one direction [2].

One of the primary characteristics of traditional distribution grid is their radial structure. Radial feeders, where power flows from the substation to the end customers, have been the common practice due to their simplicity and cost-effectiveness. This design, while less robust than meshed grids, has been widely adopted for its efficiency and fault isolation.

Distribution grids were designed to anticipate shifts in load centres, reinforce grid components such as transformers, feeders, and branches, and ensure the delivery of economical and reliable energy. The key aspects for distribution grid planning [3] are:

- **Load forecasting:** Accurate prediction of future load requirements is essential for determining when and where system upgrades or expansions are needed. Planners typically use historical data and growth projections to estimate future demand. Traditionally, non-coincident peak loading was used in the distribution planning process, which could sometimes lead to overestimation of peak forecasts.
- **Grid topology design:** Planners traditionally designed grids using idealized topologies such as radial feeder extending from substations. The distribution area was often divided into smaller sectors with load concentrated at the centre of each sector.
- **Substation planning:** The location is optimized aiming for minimal investment and operational costs while the capacity design is related with the load forecasting to meet the projected demand efficiently.
- **Feeder design:** Feeders are usually planned according to optimal routes to connect substations to the load centres while the conductor sizes are selected to handle the expected load while minimizing losses.

Cost minimization is a key objective in the traditional planning of distribution systems, aiming to minimize the fixed and variable costs associated with grid expansion and reinforcement, as well as the operational expenses (including operational losses). Additionally, ensuring system reliability was a fundamental aspect of traditional planning, with the incorporation of fault isolators and protection devices at strategic locations along feeders to quickly isolate faults and maintain service.

At the core, traditional approaches for expanding distribution grids are considering a future load growth and system requirements over a specific planning horizon. A stepwise approach was often used, employing techniques like linear programming to determine initial solutions, followed by more detailed optimization [4], [5], [6]. While these traditional methods have served the industry well for decades, they are now being complemented and, in some cases, replaced by more advanced approaches that can better handle the complexities of modern power systems, including DER and increased variability in both supply and demand.

As DER becomes more prevalent, DSOs will play a critical role in enabling their participation in local flexibility markets. On the TSO side, this decentralized generation and demand flexibility can help to balance the system. However, an effective coordination between each TSO, DSO, DO and DER (Figure 1) is required to optimize investments and leverage DER, as a local and system-wide resource.

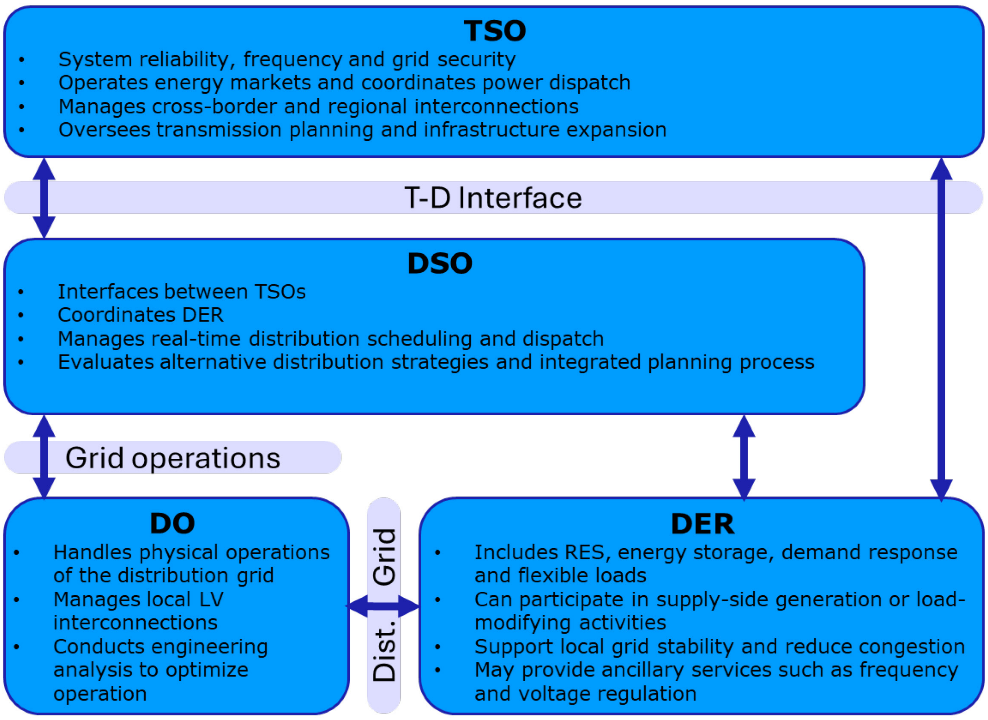


**Figure 1 – TSO-DSO-DER interaction.**

### 2.1.1. Transmission grid

Power system flexibility is crucial for maintaining balance between electricity generation and consumption. This balance refers to the system's ability to respond efficiently and cost-effectively to expected and unexpected changes in supply and demand [7].

Traditionally, power systems were designed with limited intermittent energy resources and primarily relied on dispatchable sources to cope with uncertainty. The uncertainty of the load diagram of electricity demand derives from multiple parameters, from climate, social and economic factors, including local weather patterns, the season, the level of industrialization, public energy awareness, and the gross domestic product.

Conventional power systems typically combine the most cost-efficient mix of controllable generation sources, selected for their techno-economic characteristics, to balance demand. Baseload generation units, such as coal, biomass, and nuclear power plants, primarily rely on steam turbines to produce electricity, often supplying heat in combined heat and power (CHP) systems. These units are optimized for continuous operation, delivering large-scale energy output at relatively low operational costs. In contrast, peaking generators are designed for high flexibility, featuring rapid start-up times, fast ramping capabilities, and low minimum operating levels. Typical examples include open-cycle gas turbines and internal combustion engines. Meanwhile, modern combined-cycle gas turbines (which integrate gas and steam turbines) and reservoir hydropower plants function as intermediate generators, balancing both baseload and peak demand requirements.

Over the past three decades, the conventional structure of power systems has been significantly challenged by the increasing deployment of intermittent energy sources, which is rapidly becoming the backbone of many power systems. This increase of intermittent energy share introduces new levels of variability and uncertainty into the net load, requiring a more accurate load and generation forecasting. Critical factors shaping the net load profile include ramp rate, ramping range, and forecast error, each intensifying as RES penetration increases. This dynamic amplifies the need for thermal generation cycling, raising the risk of overgeneration [8], and in extreme cases, loss of load or frequency instability.

Overgeneration risks often increase during two key periods. The first occurs in the early morning hours when thermal units operate in partial load mode, remaining on standby to meet the expected rise in demand. The second arises during peak solar production, as online thermal units are often forced to operate at their minimum output to accommodate photovoltaic generation. Additionally, overgeneration can occur during late-night hours when wind generation is high, but electricity demand is at its lowest.

As a successful example of the impact of grid planning on RES curtailment, in Texas's wind energy initiatives, the state faced a significant challenge in 2009 when wind curtailment reached 17%, primarily due to transmission constraints.  [9]. However, regulatory reforms and strategic transmission investments significantly reduced curtailment to below 0.5% by 2014. The Public Utility Commission selected transmission providers and oversaw construction, ensuring alignment between generation and grid capacity. Additionally, the state abolished outdated rules requiring high utilization of new lines and instead set a curtailment target of less than 3%, encouraging overbuilding to future-proof grid. Despite these changes, Texas promoted demand response programs, a more competitive wholesale market and forecasting improvements.

In market-based power systems, energy oversupply can drive electricity prices downward, occasionally resulting in negative pricing. While negative pricing can act as a market mechanism to rebalance the system, it also signals a lack of flexibility within the power grid. Beyond the economic impacts of overgeneration, high instantaneous shares of RES can introduce reliability challenges, particularly due to reduced system inertia, which contributed to the Iberian blackout in April 2025 [10]. Each power system has specific inertia requirements, which necessitate the continuous operation of some synchronous generation capacity. Achieving 100% instantaneous penetration of RES is particularly difficult unless the system is well interconnected and can access inertia from neighbouring regions within the same synchronous grid. For instance, in Denmark, wind penetration can exceed 140% at certain times, yet the system remains stable due to inertia support from mainland Europe (ENTSO-E) and the Nordic countries through synchronous interconnections.

Taking all these characteristics into consideration, transmission grid planning needs to cope with future generation and demand scenarios over a 10–20-year horizon. Transmission grid planning can be systemized into four key stages: data collection, scenario analysis, contingency planning, and investment prioritization. By starting with accurate data collection from various sources, TSOs can build a solid foundation for informed decision-making. After defining scenarios, planners determine the influencing factors and assumptions used to forecast future conditions, including load levels, generation mix, and public policy mandates. These scenarios are then translated into input parameters for market and grid modelling, incorporating realistic projections over the lifespan of transmission investments. Contingency planning ensures preparedness for potential disruptions, safeguarding grid stability and reliability, usually following a N-1 criteria. Finally, investment prioritization focuses on cost-effective upgrades and expansions to maintain secure operations.

### 2.1.2. Distribution grid

Historically, distribution grids were designed for one-way energy flows from central generation to end-consumers, following a traditional "fit and forget" planning approach. This approach designs grids for worst-case scenarios, primarily in terms of load and voltage drops, while holding to security constraints based on a given load forecast [11].

The grid is a highly complex and interdependent system, where any significant changes must be evaluated holistically. Such evaluations are aligned with policy objectives, customer needs, jurisdictional priorities, environmental concerns, and the constraints of existing infrastructure. A well-coordinated approach is essential to ensure that grid modernization efforts effectively support the transition to a more sustainable, resilient, and efficient energy system.

The typical planning process follows the identification of the need for grid reinforcement or expansion due to issues such as increasing demand, failing equipment, or new connections. In Figure 2, it is illustrated the typical planning process for passive distribution grids.

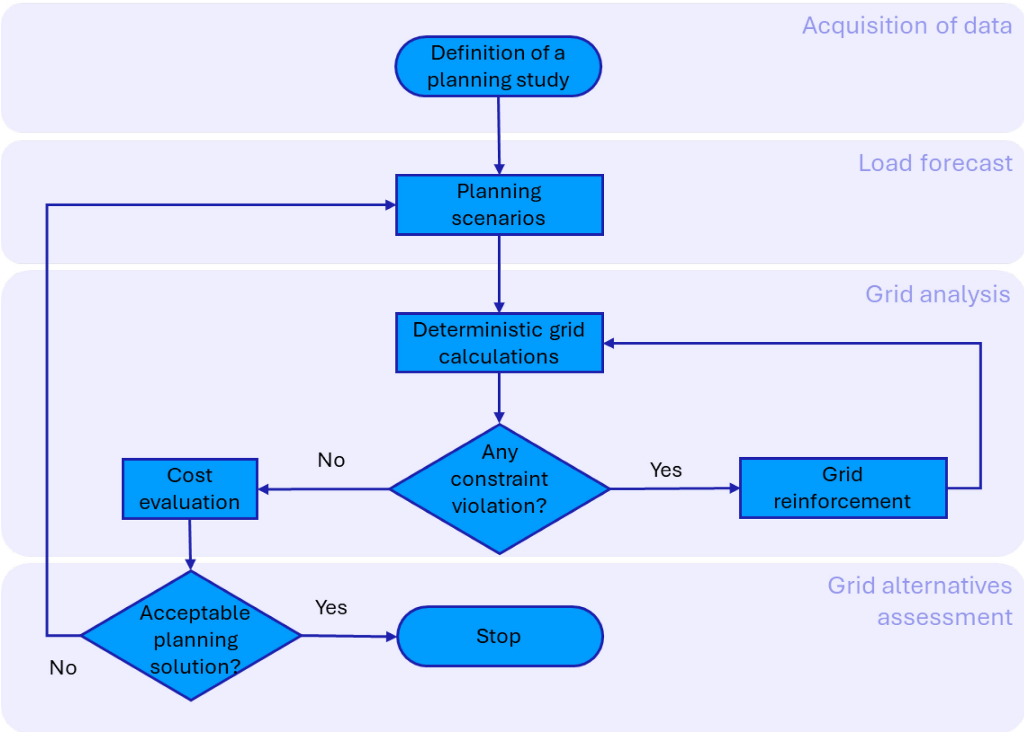


**Figure 2 – Traditional planning framework for distribution grids.**

The traditional planning framework can be divided into 4 main steps:

- Grid planning heavily relies on **acquisition of data** on customer consumption and city planning information to create accurate load forecasts. Utilities typically gather this data from official sources, authorities, and large customers, requesting details on urban planning, economic growth, and new developments [12]. While major customers provide future demand insights, only large consumers and producers report on generation. However, despite these efforts, there is often a lack of information on distributed generation. A survey conducted by the CIGRE WG C1.29 [13] highlights the need for accurate and granular historical data as a key planning priority, as it improves forecasting accuracy and enables informed decision-making.

- **Load forecast** methodologies include historical data trends, macroeconomic models, weather data, and spatial demand analysis, often including regional and country planning information. Many utilities develop in-house forecasting tools, though these methodologies are usually not standardized, with smaller utilities sometimes using purchased tools [14]. Forecasts primarily focus on load demand, while distributed generation is rarely integrated due to "fit-and-forget" strategies. While national generation plans at the European level include future renewable energy contributions, they do not specify exact locations or sizes, further complicating grid planning [15].

- On **grid analysis,** various tools—ranging from in-house solutions to commercial software like PSS-ADEPT, PSS/E, DPlan, PSS Sincal, PSCAD, DIgSILENT, ETap, DINIS, Matlab, Anarede, Anatem, Anafas, Cyme, IPSA, NEPLAN, Interplan, and OpenDSS—are used for power flow, voltage variation, short circuit analysis, and equipment ratings. [13] Studies typically model the grid over 10–20 years, aligning with national and international standards while considering feeder losses and reactive power. Most analyses are deterministic, examining extreme scenarios, though probabilistic methods are become increasingly more frequent [16]. Some utilities conduct proactive, detailed MV feeder studies, while others only react to issues. The approach depends on the availability and accuracy of grid data. Studies generally focus on basic load-flow and fault level calculations to ensure compliance with power quality standards and identify overloaded components [17]. Calculation tools often have a linkage with GIS mapping. Typical studies include power flow calculation, power quality analysis, short circuit analysis, transient stability analysis, protective relaying, reliability analysis, voltage control/tap changer settings, harmonic analysis, and dynamic analysis.
- Utilities develop **grid alternatives assessment** based on company policies, regulations, and standards, typically after identifying future grid bottlenecks. Risk-based planning techniques and reliability indices (e.g., SAIDI, SAIFI) are used in some assessments. Most utilities rely on internally developed tools (often Excel-based), while only a few have economic lifecycle models for selecting alternatives. Grid alternatives are often chosen based on minimum thermal and voltage requirements while adhering to budget constraints.

The following SWOT analysis, Table 2, summarizes the key characteristics of traditional distribution grid planning approaches. It highlights their foundational role in the system reliability, while addressing the new challenges in the face of increasing decentralization and variability. The table also identifies the emerging opportunities enabled by digitalization alongside the threats posed by a growing system's complexity.

**Table 2 – SWOT Analysis of Traditional Distribution Grid Planning Approaches.**

| Strengths | Weaknesses |
|---|---|
| - Utilizes simplified and well-established grid models, enabling systematic identification of extreme operating conditions and contingency scenarios.<br>- Relies on clearly defined technical thresholds (e.g., voltage and thermal loading limits) as outlined in regulatory documents such as national grid codes.<br>- Based on long-standing forecasting methodologies for load growth and user behaviour, which have historically provided reliable planning baselines. | - Highly dependent on deterministic forecasts of load and generation, which may not adequately represent the variability and uncertainty introduced by DERs and electrification.<br>- Limited data exchange between TSOs and DSOs, often restricted to static or historical datasets.<br>- Planning processes are typically siloed, with differing priorities between system operators and limited visibility into DER behaviour and flexibility potential.<br>- Inflexible to real-time operational dynamics and emerging technologies. |
| **Opportunities** | **Threats** |
| - Growing acceptance of enhanced data sharing protocols and digitalization opens the door for more granular and dynamic planning inputs.<br>- Availability of high-resolution consumption and generation data enables refinement of load aggregation rules (e.g., simultaneity coefficients) and improved scenario modelling.<br>- Integration of DERs and flexible resources can be leveraged to defer or optimize traditional infrastructure investments. | - Increased complexity from active grid management at MV and LV levels introduces new operational contingencies that classical models are not designed to handle.<br>- The number of required simulations grows exponentially with the inclusion of DER variability, leading to computational challenges and potential planning delays.<br>- Risk of under- or over-sizing infrastructure due to outdated assumptions or lack of coordination across grid levels. |

## 2.2. Evolution of grid planning to accommodate flexibility

### 2.2.1. Transmission grid

The transmission grid itself is not a direct source of flexibility, although it can easily become a limiting factor in its deployment and utilization. This is particularly evident considering that regions with high wind resource potential are often geographically distant from major load centres. Therefore, when planning for a flexible power system, the application of geospatial planning techniques can be instrumental in illuminating the trade-offs between the costs associated with transmission infrastructure and the overall productivity of renewable generation. Effective flexibility planning dictates a holistic approach that encompasses various sources of flexibility and considers their interdependencies. These sources can be broadly categorized as technical, supply-side, energy storage, demand-side and operational flexibility.

- **Technical flexibility**, closely tied to the system's physical infrastructure and implemented technologies, depends on several key factors. These include the system's capability to handle rapid changes in net load, its responsiveness to fluctuations in both supply and demand across various timescales, and the adequacy of grid infrastructure to ensure the cost-efficient delivery of electricity to meet demand.

- **Supply-side flexibility** is primarily related to the flexibility inherent in various generation technologies. A flexible generator is characterized by its ability to ramp up or down quickly, maintain a low minimum operating level, and exhibit rapid start-up and shutdown times. For instance, hydro generators and open-cycle gas turbines are among the most flexible conventional generation technologies, whereas large steam turbines from coal and nuclear generators typically exhibit lower flexibility.
- The past two decades have witnessed a surge in the interest in **electricity storage** technologies, extending beyond traditional pumped hydro solutions. This growth is powered by advancements in battery technologies, significant cost reductions, and the escalating need to effectively integrate RES sources into power systems. As RES penetration increases, energy storage is increasingly deployed to mitigate the impact on grid operations, balancing fluctuations that occur on timescales ranging from seconds to years. Different storage technologies offer a spectrum of capabilities based on response time, power capacity, and energy storage duration, rendering them suitable for applications spanning short-term frequency regulation to long-term energy balancing. While pumped hydro continues to dominate the global storage landscape due to its economic viability and its ability to provide essential grid services like inertia and flexibility, batteries are emerging as a critical complement due to their operational advantages and anticipated future cost reductions.
- **Demand-side flexibility**, particularly when coupled with energy storage, can significantly reduce RES curtailment by strategically shifting electricity consumption to better align with periods of high-RES supply. This approach empowers consumers to actively participate in grid operations by adjusting their electricity usage in response to price signals or through direct-control agreements. Direct control programs, often implemented in industrial settings, provide additional operational reserves to address RES uncertainty, further contributing to grid stabilization. A key challenge in the implementation of demand response lies in effectively coordinating the diverse array of loads connected to MV and LV distribution grids to achieve the desired capacity reductions. Market mechanisms often facilitate the role of aggregators, who consolidate demand from residential, commercial, and industrial consumers to enhance overall system flexibility. However, the effectiveness of demand response diminishes as its deployment expands, necessitating a careful economic and technical evaluation to identify optimal levels of demand response in conjunction with other flexible resources to achieve a cost-effective and resilient energy transition.

- **Operational flexibility** in power systems is the ability to efficiently adapt and adjust system operations while complying with technological, regulatory, and market constraints. It is not solely determined by the technical capabilities of individual assets but is also shaped by the broader regulatory and market environment governing grid operations. A well-structured market and regulatory framework can greatly enhance flexibility, while fragmented markets, such as isolated provincial systems within larger countries, can hinder it by restricting energy exchanges and limiting supply-side flexibility.

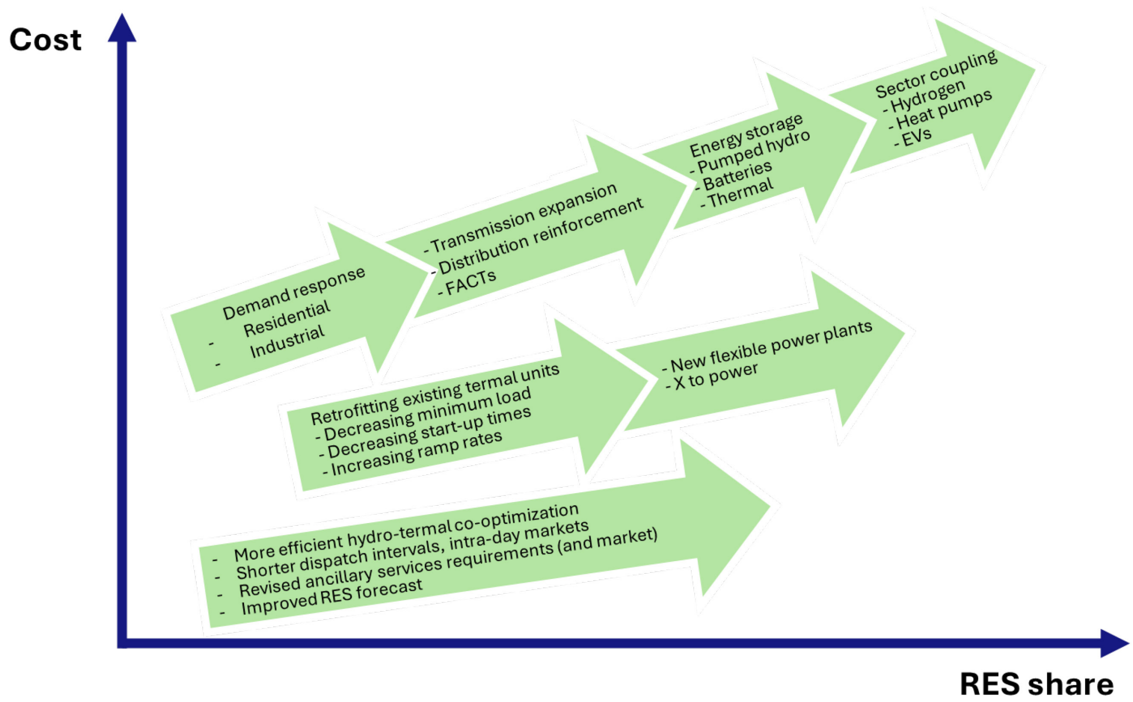


**Figure 3 – Strategies to enhance transmission grid flexibility (based on [18]).**

Flexibility in transmission power systems (Figure 3) must be addressed across multiple time scales, as solar and wind variability and uncertainty affect system operations across different time scales, ranging from seconds (due to cloud passage over a PV farm) to months (seasonal variability of RES). Consequently, system-wide impacts of solar and wind variability exhibit a related temporal dependency. Short-term variability affects frequency regulation, while variability at time scales of 15 to 30 minutes influences load following and operational reserve sizing. Furthermore, planning for flexibility must account for the effects of variability on decisions such as EV charging/discharging

In the long term, regulators should promote investment in flexible resources through mechanisms like capacity markets and improved wholesale market granularity. Seasonal and inter-annual variability, particularly in hydro-dominated systems, requires robust scheduling under uncertainty. In the medium term, optimizing economic dispatch and generation through well-structured day-ahead and intra-day markets is crucial. Additionally, increasing temporal and spatial granularity, such as transitioning from zonal to nodal pricing or reducing settlement periods, further enhances market flexibility [19].

In the short term, ancillary services markets play a vital role in grid stability. Regulators must design operating reserves that incentivize flexible resources, including fast frequency response (FFR) from batteries and RES with advanced power electronics. A key challenge is determining the extent to which system inertia can be replaced by these fast-acting resources. Market reforms, such as enabling central dispatching and price-based electricity exchanges, are essential to unlocking flexibility and ensuring a cost-effective energy transition.

To effectively support this multi-scale approach to flexibility, transmission planning must evolve in parallel, integrating new methodologies that align infrastructure development with the dynamic needs of increasingly variable power system. Below are some key methodologies used in transmission planning.

**Table 3 – Overview of transmission planning methodologies.**

| Methodology | Key Features | Applications | References |
|---|---|---|---|
| Integrated Transmission Planning (ITP) | Combines near-term, 10-year, and NERC assessments into a single study; produces 10-year expansion plans. | Balancing long-term investments with congestion costs; annual cycle for reliability. | [20], [21] |
| Long-Term Transmission Planning | Uses advanced optimization, Monte Carlo simulations, and grid reduction for 20–30-year horizons. | Large-scale grid expansion; addressing renewable energy variability and load growth. | [22] |
| Probabilistic Contingency Methodologies | Replaces N-1 criteria with probabilistic methods to account for uncertainties in renewables and load. | Enhancing grid resilience and flexibility in uncertain environments. | [23], [24], [25] |
| Scenario-Based Planning | Constructs multiple generation-demand scenarios; harmonizes with regional plans; iterative assessments. | Aligning grid expansion with future energy strategies and uncertainties. | [26], [27] |
| Transmission Expansion Planning (TEP) Models | Optimizes placement of new transmission lines and generation units; includes TCSC and FCL planning. | Identifying optimal locations for infrastructure; enhancing grid reliability. | [28], [29], [30], [31] |
| Renewable Energy Zone (REZ) Process | Optimizes renewable energy siting; incorporates distributed renewable impacts; anticipates grid controls. | Managing renewable integration and grid stability. | [32], [33] |

| Methodology | Key Features | Applications | References |
|---|---|---|---|
| Numerical Decomposition Techniques | Reduces computation time for complex grid models by simplifying optimization problems. | Efficient analysis of large-scale transmission systems in long-term planning. | [34], [35], [36] |

A recently developed methodology was proposed by IRENA working group [7] for flexibility planning in transmission power systems for scenarios of high-RES shares. Central to this methodology is the principle of early-stage planning and system assessment, which enables stakeholders to anticipate flexibility needs and avoid reactive, and costly interventions.

The methodology employs an advanced tool called IRENA FlexTool to analyse flexibility across demand-side resources, storage, and sector coupling. It integrates production cost modelling and grid modelling studies to simulate the behaviour under various scenarios, identifying operational constraints, curtailment risks and reliability challenges. A flexibility gap analysis follows, guiding the development of targeted strategies that may include regulatory reforms, infrastructure investments or demand-side interventions. Importantly, the approach incorporates probabilistic modelling and scenario analysis with emphasis on economic optimization, balancing technical requirements with cost-effectiveness.

### 2.2.2. Distribution grid

The distribution grid planning process is undergoing a significant transformation as it adapts to the growing adoption of DERs and the increasing need for flexibility in grid operations. The three-stage framework (Figure 4) outlines how the distribution system is expected to evolve in response to both top-down and bottom-up drivers. The top-down drivers include public policies that incentivize decarbonization targets, renewable energy integration, and smart grid initiatives. Meanwhile, the bottom-up drivers originate from customer choices, including the adoption of EVs, rooftop solar panels, and energy storage solutions, which are reshaping grid demands.

In this framework, each stage builds upon the previous one, incorporating additional functionalities and capabilities to accommodate increasing levels of DER adoption and integration. At each stage, the grid evolves to become more flexible and resilient, with advanced monitoring, control, and communication systems being introduced to support the evolving landscape. The first stage may focus on integrating simple DERs and addressing basic grid stability, while the second and third stages might introduce more complex demand response mechanisms, vehicle-to-everything (V2X) technologies, as well as advanced analytics for real-time decision-making.

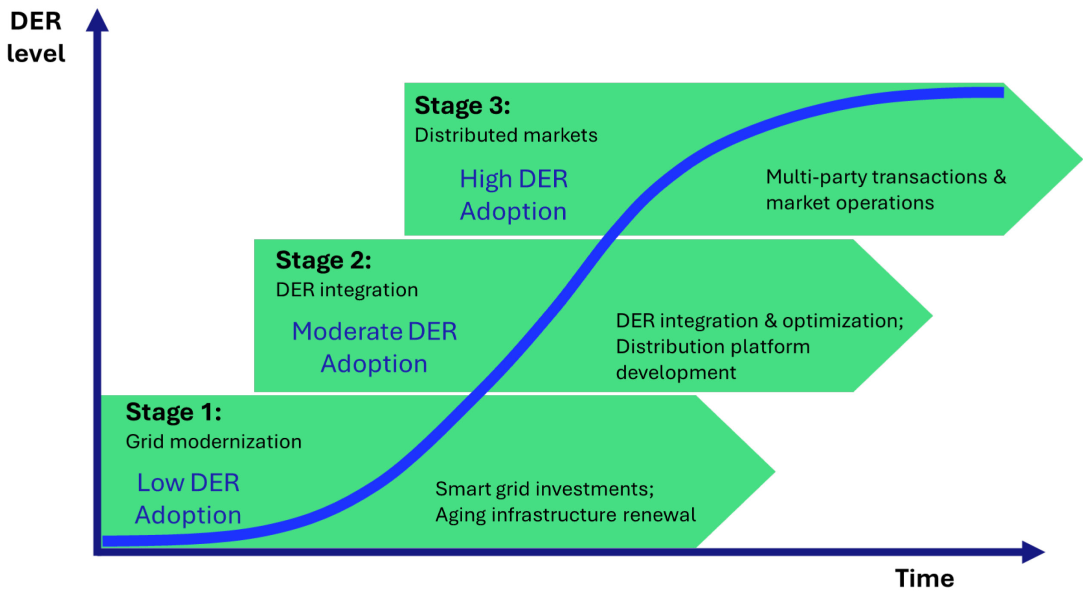


**Figure 4 – Evolution of DER Adoption and Grid Modernization.**

**Stage 1: Grid Modernization**: In Europe, many utilities are still operating within this stage, characterized by low DER adoption, which can be integrated without major infrastructure changes. Utilities should prepare for increasing DER penetration by assessing hosting capacity and streamlining interconnection processes.

**Stage 2: DER Integration:** When DER adoption exceeds ~5% of peak load, requiring advanced grid management capabilities. Bi-directional power flows create challenges, necessitating enhanced protection, control, and coordination between distribution and transmission operators. Some countries like Germany, Netherlands, Denmark, UK, France, Norway, Sweden, Finland, Spain, Portugal, Italy and Austria are in this stage.

**Stage 3: Distributed Markets**: A future phase where high DER penetration and regulatory changes enable peer-to-peer energy trading. This requires local distribution markets and coordination between DSOs and TSOs. Implementation will begin in high-DER areas, with potential pilots in other regions. The Netherlands has active local flexibility markets as well as a supportive innovative regulation ecosystem, being one of the countries closest to Stage 3.

Considering the new paradigm shift towards DER massification, the "fit-and-forget" approach is the most applied, where grids are designed based on maximum generation-minimum demand scenarios that are infrequent for RES. DSOs typically offer firm capacity access to medium-scale DG plants, but this reduces grid hosting capacity with each new connection. Some DSOs have adopted non-firm connections, which temporarily disconnect generators to alleviate grid constraints. This helps expand hosting capacity but can reach its limits quickly.

Small-scale DG, like domestic photovoltaic panels or micro-CHP, follows different rules and requires minimal DSO control, leading to potential technical issues in low-voltage circuits. Meanwhile, the electrification of transport and other sectors could significantly increase demand, triggering the need for substantial grid reinforcements.

With the increasing penetration of DG in MV grids, particularly in Europe, coordinated control approaches were initially considered to mitigate issues like voltage fluctuations and congestion. These approaches evolved to include multiple DG plants, electricity storage, and demand-side management. However, most studies have focused on operational challenges rather than planning aspects [37], [38].

The growing recognition of the need for active distribution grid management led to the formation of the CIGRE WG C6.11 in 2006, which emphasized that active grids impact all planning activities, such as how DG affects load forecasting and how active management influences system design.

A 2014 survey by the WG C6.19 Survey Task Force revealed that 90% of utilities still follow traditional planning processes [39]. An active distribution system (ADS) is defined by the integration of distributed generation, controllable loads, and energy storage systems within the distribution grid. Key features of ADS include two-way power flows, active system control, and advanced management supported by new communication technologies aimed at optimizing power flow.

Planning for ADS operation requires access to high-resolution, real-time data on grid conditions, the availability of distributed generation, and evolving load profiles. Unfortunately, such data is not always readily available or reliable during the long-term planning phase, which poses a significant challenge. In addition, accurately simulating how an ADS will behave under different operating conditions demands the use of advanced modelling and simulation tools. These tools must be capable of incorporating complex control algorithms and accounting for multiple sources of uncertainty, including fluctuations in DER output, variations in load demand, and changing market prices.

Given these challenges, probabilistic approaches are better suited to capturing the uncertain nature of both energy demand and generation. To support this approach, several authors and international organizations have proposed general planning frameworks that aim to address the unique characteristics of ADS [40], [41], [42], [43]. Although these frameworks are gaining recognition, they have yet to be fully implemented by most DSOs, indicating a gap between research-driven recommendations and practical application in the field.

Figure 5 illustrates the process of active distribution grid planning which starts by defining the study's scope and objectives, followed by accurate demand load modelling that considers future growth and new technologies such as EVs.

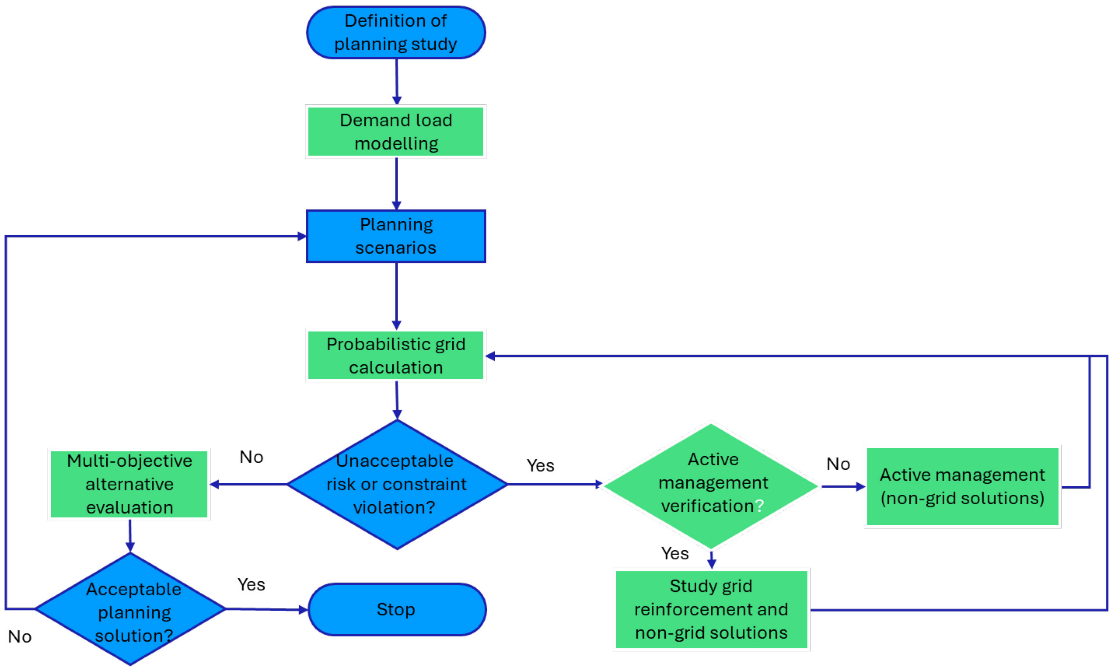


**Figure 5 – Iterative active grid planning.**

Planners develop multiple scenarios to test the grid's performance under various conditions and use probabilistic calculations to assess reliability and risks. If no critical issues arise, the solution is evaluated for acceptability, otherwise, active management techniques, such as demand response or grid automation, are considered. If these are insufficient, alternative reinforcement options are assessed based on cost, environmental impact or supply quality. The process iterates, refining scenarios and solutions until a technically, economically and regulatorily acceptable solution is found.

The previous depicted process spans several key domains of active grid planning, including:

- **Technology:** Traditional grid voltage regulation and reactive power compensation have predominantly relied on static solutions such as OLTCs, autotransformers, capacitor banks, synchronous condensers and static VAR compensators (SVCs) [44], [45]. While these provide essential voltage control, their mechanical switching and fixed ranges limit dynamic responsiveness. Recent advances in power electronics have introduced dynamic adaptive solutions such as Static Synchronous Compensators (S-STATCOMs) which offer fast reactive power support. Other innovations include Dynamic Voltage Restorers (DVRs) for real-time harmonic mitigation, hybrid distribution transformers combining bidirectional flow with IoT monitoring, and Solid-State Transformers (SSTs) that enable advanced AC/DC grid interfacing.

- **Tool improvement:** To meet current demands towards decentralization and higher penetrations of renewable energy sources, planning tools must undergo significant improvements in key areas: Data modelling, probabilistic approach, multi-objective approach and ADS solutions integration.
    - Data modelling: A major challenge in active demand planning is accurate forecasting of both electricity demand and distributed generation. Current forecasting methods vary widely, with larger utilities using custom tools and smaller ones relying on standard software, leading to inconsistencies in grid planning. An additional complexity lies in predicting prosumer participation. User responsiveness varies based on price signals, flexibility potential, and individual comfort thresholds. As such, behavioural modelling and acceptance models are critical to forecast actual engagement levels and integrate user behaviour effectively into planning frameworks.
    - Probabilistic approach: Unlike traditional deterministic methods, probabilistic planning allows utilities to treat RES as both a challenge and a resource, requiring significant updates to existing planning tools. Reliability assessment techniques, originally developed for transmission systems, are now being adapted for distribution grids, using either analytical models (state enumeration) or simulation-based methods. Among these, simulation approaches like Monte Carlo Simulation (non-sequential, pseudo-sequential and sequential) offer greater flexibility and realism, making them particularly effective
    - Multi-objective optimization: This step integrates risk analysis with multi-objective optimization to evaluate different planning alternatives.
    - Active management integration: Research and pilot projects will demonstrate the advantages of ADS, while regulatory frameworks must evolve to support active distribution management.
- **Demand side integration:** Demand side integration (DSI) enables fully integrated real-time interaction with end-users by supporting advanced functionalities such as Volt/VAR optimization and feeder reconfiguration, leveraging granular data for improved grid analysis. DSI supersedes older approaches like demand side management and demand side response by offering a more dynamic, integrated, and market-aligned framework.

- **Storage:** Storage systems play a multifunctional role in mitigating the variability of generation on modern distribution grids, particularly within the context of DSI. Two key applications stand out:
    - Peak Shaving: Storage discharges during high-demand periods to keep the overall load below critical thresholds. For effective grid planning, storage must be analyzed in conjunction with load and Distributed Generation models. This reduces grid congestion and can lower infrastructure costs by deferring or avoiding reinforcements.
    - Load Following: Storage systems dynamically respond to load fluctuations using control algorithms that trigger discharging based on time windows or demand thresholds.
- **Electric vehicles:** Uncontrolled charging during peak hours leads to substantial grid stress. Notwithstanding, multi-tariff pricing strategies that incentive off-peak charging can significantly reduce reinforcement needs. Nevertheless, these tariffs could lead to charging synchronization, thus overloading the system. At high EV penetration levels, particularly in LV urban grids, several impacts become evident: Increased power losses; Voltage drops; Thermal overloading of MV/LV transformers and nearby feeder cables; Voltage imbalance and harmonic distortion, affecting power quality. Simulation studies indicate that the most critical limiting elements are often the MV/LV transformer capacity and the main LV feeder infrastructure. While rural grids experience different load profiles and lower density, they still require detailed evaluation to ensure reliable operation and avoid overload.
- **Integrated distribution planning (IDP) and interconnection:** Effective integration requires coordinated planning processes, where insights from distribution-level DER deployment inform transmission-level decisions, enabling smarter, non-wires alternatives to traditional upgrades (particularly relevant in islanded grids)**.** Unlike older, passive approaches, IDP incorporates scenario-based probabilistic planning, dynamic hosting capacity assessments (thermal limits, voltage constraints, and protection schemes), and locational valuation of DERs to support more resilient and adaptive power systems. It emphasizes the importance of modernizing interconnection processes to align with these planning advancements, enabling the safe and efficient integration of multi-functional DERs like storage and EV charging hubs.
- **Market and Regulation:** As DERs become more embedded in the power system, regulatory and market frameworks must evolve to enable their full participation. This includes establishing fair, technology-neutral compensation mechanisms, supporting DER multiple-use applications (e.g. frequency regulation), and ensuring clear

interconnection rules and market access to avoid double-counting or interference. On price definition, designing DER-inclusive markets is complicated by pricing granularity. While sub-minute, feeder-level pricing may provide precision, it may also prove impractical. Aggregated pricing at the substation or feeder level could offer a more scalable and effective approach. DSOs may be required to expand roles in aggregation, dispatch coordination, storage services, and micro-transaction between prosumers and other market participants.

To synthesize the different elements discussed above, it is important to contextualize them within established and emerging distribution planning methodologies. These methodologies presented in Table 4 provide the analytical backbone for integrating technological advancements, tool enhancements and evolving regulatory framework into coherent planning strategies to accommodate flexibility.

**Table 4 – Overview of distribution planning methodologies.**

| Methodology | Key Features | Applications | References |
|---|---|---|---|
| Scenario-Based Probabilistic Planning | Incorporates uncertainty in DER adoption, load growth, and system behaviour. | Long-term planning, investment deferral and climate resilience. | [46], [47], [48], [49] |
| Hosting Capacity Analysis | Evaluates thermal, voltage, and protection limits under various DER scenarios. | DER integration planning, grid reinforcement prioritization. | [50], [51], [52] |
| Locational Net Value Assessment | Quantifies DER value based on location-specific grid impacts and avoided costs. | Siting of DERs, tariff design, non-wires alternatives. | [53], [54] |
| Integrated T&D Planning | Aligns distribution and transmission planning processes and data flows. | Coordinated investment planning, DER impact assessment. | [55], [56] |
| Dynamic Grid Reconfiguration | Real-time switching and topology optimization using automation and sensors. | Fault isolation, congestion management, voltage control. | [57] |
| AI-Based Forecasting and Optimization | Uses machine learning for load, generation, and flexibility potential forecasting. | Operational planning, congestion prediction, DER dispatch optimization. | [58], [59] |

## 2.3. Country-specific approaches

This subchapter provides a comparative assessment of transmission and distribution grid planning methodologies across different participating countries in the AHEAD project. It examines how each country address challenges like renewable integration and reliability, identifying transferable lessons and strategies.

### 2.3.1. Albania

**Table 5 – Transmission grid planning in Albania.**

**Albania**

**Guidelines**

Transmission grid planning in Albania is framed by both national and European frameworks, notably the National Energy & Climate Plan 2020–2030 (NECP) and the transposed EU Clean Energy Package, which set renewable energy and decarbonization targets guiding infrastructure development toward mid-century climate goals. Planning follows a rolling 10-year horizon to ensure the transmission grid can meet forecast demand growth, integrate new renewable capacity, primarily hydropower and increasingly solar PV, and accommodate emerging technologies such as grid-scale storage and demand-response services.

A core priority is the seamless integration of renewables: siting and corridor selection leverage ASIG's GIS portal for spatial analyses, while grid reinforcements focus on boosting transfer capacity to high-resource regions and cross-border interconnectors. Coordination between the TSO (OST sh.a.) and distribution grid operators is institutionalized through joint operational procedures and data-sharing platforms to manage distributed generation and ensure secure bidirectional flows. Stakeholder engagement is embedded throughout the process, with public consultations and hearings conducted under ERE Decision 162/20.10.2020, bringing together policymakers, regulators (ERE), utilities, civil society and technical experts to align planning outcomes with national priorities and local concerns.

Technical standards are rigorously applied: the N-1 security criterion and ENTSO-E System Operation Guidelines underpin all studies, while detailed grid-connection requirements (fault-ride-through, reactive-power support, metering) are enforced via the Transmission Code and related ERE decisions. The principal planning instrument is OST's Ten-Year Development Plan, submitted to ERE for approval, which for the 2015–2025 cycle allocated €59.8 million across 27 priority projects. Updates are now underway for the 2026–2036 masterplan, reflecting revised NECP targets and anticipated grid needs.

**Planning**

Albania's transmission planning is tightly aligned with its NECP 2020–2030 targets for renewable deployment, shifting from a predominantly hydropower-based mix (2 238 MW) towards a more diversified portfolio including utility-scale solar PV and emerging onshore wind. Spatial analyses via ASIG's GIS portal drive the identification of optimal REZs, balancing high-irradiance and wind resource areas with existing grid infrastructure to minimize reinforcement costs and curtailment risks.

In densely populated corridors, such as around Tirana, OST has begun piloting the conversion of select 110 kV overhead lines to underground cables to improve visual amenity and enhance supply resilience, while new substations are sited to capture regional load growth under strict

**Albania**

N-1 security criteria. To facilitate large-scale RES integration without extensive reinforcements up front, planning includes provisions for initially building double-circuit towers but energizing only one line, employing phased voltage uprating schemes, and installing phase-shift transformers to flexibly manage power flows and relieve bottlenecks.

Flexibility considerations are embedded via dynamic nodal capacity studies, updated regularly to inform developers of available headroom for new connections, and by the market-based procurement of ancillary services under ERE Decision 106/2020, with imbalance and frequency control products auctioned on ALPEX since April 2023. Financially, ERE ensures cost recovery for OST's capital investments through the regulated transmission tariff framework (Law 43/2015 Arts 56–62), incentivizing efficiency and safeguarding the TSO's long-term economic sustainability [60], [61], [62].

**Table 6 – Distribution grid planning in Albania.**

**Albania**

**Guidelines**

In Albania, the distribution grid planning process is led by the national Distribution System Operator (OSHEE), which prepares a rolling five-year Distribution Grid Development Plan. This plan is updated annually and submitted to the Energy Regulatory Authority (ERE) for review and approval, in coordination with the Ministry of Infrastructure and Energy to ensure alignment with national energy strategy and policy goals. The plan must detail the DSO's proposed investments and measures over the period, including actions for improving energy efficiency, demand management, grid expansion/upgrades, and modernization of the metering system, along with information on financing for these investments. Plan development is informed by transmission system expansion plans and urban/regional development plans to ensure coherent overall system growth, and it follows technical criteria set out in the Distribution Code (e.g. design and reliability standards for substations, feeders and lines). ERE oversees the process by issuing regulatory guidelines and assessing whether the plan meets its approval criteria – for example, verifying that the proposed investments will improve service reliability and reduce technical and non-technical losses – before granting approval. Distribution grids operate under a license-concession framework: OSHEE holds the exclusive rights to develop and operate the country's medium- and low-voltage distribution grids. Environmental considerations are integrated into the planning process; the construction of major new distribution infrastructure (such as high-voltage feeders or large substations) may require a full Environmental Impact Assessment in accordance with national law, and each investment in the plan is accompanied by an environmental impact study as needed. Stakeholder engagement is also ensured, as draft distribution investment plans must be made public to allow input from interested parties and

**Albania**

relevant state institutions before approval, providing transparency and opportunities for public consultation in line with Albanian energy sector regulations.

## Planning

In Albania, distribution grid planning by OSHEE Sh.a., the main DSO, is anchored in a structured methodology built around strategic pillars of grid expansion, asset renewal, and quality of service improvement. OSHEE prepares multi-year development plans (updated annually) that prioritize reducing losses and improving reliability, guided by key performance metrics such as energy not supplied, grid losses, and outage indices. Through aggressive investments and grid upgrades, distribution losses have nearly halved over the past decade (from ~36% in 2014 to ~18.9% in 2023 and reliability indices are steadily improving – for example, the SAIDI (average interruption duration per customer) fell from about 54.7 to 50.2 hours between 2022 and 2023 (though still above regulatory targets). Planning efforts focus on relieving capacity bottlenecks in high-growth areas and replacing aging infrastructure: OSHEE's vast ~45,000 km distribution grid is among the oldest in the region, with 40% of its 178 substations over 70 years old and still lacking full automation. Accordingly, recent plans emphasize refurbishment in major load centres like Tirana and Durrës (which account for roughly half of Albania's electricity demand), alongside grid reinforcement to meet growing consumption and new renewable connections. Advanced digital tools are increasingly used to support this planning process – OSHEE is deploying an upgraded SCADA/ADMS platform for its distribution control centre, integrating it with GIS-based grid models and an expanding smart metering infrastructure. These tools enable detailed power-flow simulations, better load forecasting, and data-driven asset management, addressing past gaps when large portions of the grid were operated manually with limited real-time information and virtually no forward demand modelling. OSHEE is also exploring probabilistic planning methods to account for demand uncertainty and renewable intermittency, in part by leveraging expertise from academic collaborations and technical assistance, for instance, an EBRD-supported program is currently building internal analytical capacity and improving the long-term grid investment planning process. All investment proposals undergo rigorous economic appraisal (e.g. calculating benefit-cost ratios, NPV and IRR) to ensure cost-effectiveness. Projects are ranked by their impact on reducing outages and losses versus their cost and are vetted by the regulator (ERE) under performance-based criteria, aligning capital spending with tangible service improvements. Finally, OSHEE's planning framework has started to incorporate flexibility alternatives to traditional grid expansion. In line with EU best practices, the DSO envisions an "active grid" model that leverages distributed energy resources and demand-side response to support the grid. OSHEE is evaluating options such as using prosumer solar generation, battery storage, and demand response programs as non-wires solutions to defer upgrades and enhance resilience. While formal market-based flexibility services in the distribution sector remain nascent in Albania, the company – in coordination with the energy regulator and international partners (EBRD, KfW,

**Albania**

etc.) – has launched initial pilots and studies to integrate these new resources into its planning. This comprehensive approach allows OSHEE to steadily improve core grid reliability and efficiency, while positioning the grid to accommodate future flexibility and smart grid capabilities [63].

### 2.3.2. Denmark

**Table 7 – Transmission grid planning in Denmark.**

**Denmark**

**Guidelines**

The planning of the transmission system in Denmark is governed by both national and European regulations. Every two years, the Danish TSO, Energinet, publishes an updated version of the long-term grid development plan (LUP), which outlines the transition towards 2050 [64]. In this report, the electricity system, the natural gas system, and the hydrogen infrastructure are described collectively. The plan establishes renewable energy and decarbonization targets, laying out the pathway to achieving carbon neutrality by 2050.

The LUP is based on ”*Analyseforudsætninger til Energinet*”, a set of analysis assumptions provided by the Danish Energy Agency *Energistyrelsen* [65]. These assumptions are published annually and developed through a consultation process with relevant stakeholders.

The planning process emphasises both the long- and medium-term development of Denmark's energy infrastructure, incorporating variable renewable energy sources and projected future demand. Two key milestones are considered in the report: the years 2030 and 2050. The LUP highlights four major drivers shaping the future energy system: 1) the need to expand the power grid to meet future requirements, 2) the importance of efficient grid utilisation, 3) the increasing demand for ancillary services, and 4) the need for a competitive green gas system.

**Planning**

Transmission grid development in Denmark is being driven by accelerated green energy production. Denmark has set ambitious targets for renewable energy installations by 2030, including 4.2 GW of offshore wind, 6.4 GW of onshore wind, and 20.9 GW of solar photovoltaic. By 2050, these figures are projected to grow to 44.2 GW of offshore wind, 5.5 GW of onshore wind, and 44.7 GW of photovoltaic, respectively [66]. In particular, the expansion of offshore wind capacity is expected to be a key driver of transmission grid development, as these generation units are typically located far from consumption centres.

One example of the necessary transmission grid expansion due to the increase of offshore wind power can be found along the west coast of the Danish mainland, Jutland. In 2015, it was decided to extend the grid in this area with a 400 kV connection. The initial plan involved a single 400 kV system, but it was later revised to include two 400 kV systems on the same pylons.

**Denmark**

Now, even before the expansion has been fully carried out, it has become evident that additional 400 kV connections will be required in the coming decades.

In eastern Denmark, a 400 kV connection is being constructed in North and Central Zealand. Its purpose is to transport electricity from West and South Zealand, Lolland, and Falster to the primary consumption centre in Copenhagen or to the interconnectors with Germany and Sweden. Furthermore, in 2024, Energinet received approval for another 400 kV expansion through Central Zealand, which will further enhance transmission capacity in the region.

Regarding financial mechanisms, the Danish Energy Regulator, *Forsyningstilsynet,* oversees cost recovery for the TSO via grid tariffs. Energinet issues two types of tariffs: the so-called *Nettarif* (grid tariff) and *Systemtarif* (system tariff) [67]. The former covers investments, depreciation, and maintenance of grid assets, while the latter funds operations, security of supply, and administration costs.

Flexibility is not a central focus in Energinet's latest long-term grid development plan. However, Energinet does offer conditional connection agreements that involve non-firm grid capacity or options with reduced security of supply in exchange for lower grid tariff levels [68]

**Table 8 – Distribution grid planning in Denmark.**

**Denmark**

## Guidelines

Each DSO in Denmark is required to submit a non-legally binding grid development plan to the Danish Energy Regulator, *Forsyningstilsynet,* every two years. This plan follows a standardized structure provided by the regulator and looks ten years into the future. The ten-year timeline is further divided into smaller timeframes for more detailed planning [69], [70] Like the transmission system long-term development plan (LUP), the foundation for distribution grid planning are *Energistyrelsen's* analysis assumptions, which forecast the future growth of distributed energy resources.

All DSOs must submit their grid development plans by April every two years. These plans then enter a public consultation process, during which the regulator, organizations, and even private citizens may provide feedback and engage in dialogue with the DSOs. A revised, final version of the plan can be submitted by the DSOs before Christmas of the same year [71].

Each DSO's grid development plan must include a comprehensive overview of the grid area, including any special circumstances, and a classification of customers by type. It should also identify major installations expected in the future that are likely to influence electricity consumption. In addition, the plan must present data on electricity consumption, grid losses, electricity production, and grid-connected storage within the DSO's area. This information

**Denmark**

should be provided both for the current state of the grid and for future projections. The plan must further highlight any HV and MV substations or lines anticipated to face overloading or voltage violations in the future. Based on these findings, DSOs are required to outline the expected investment needs per voltage level over the next ten years. Finally, each plan must describe the current use of flexibility within the grid and demonstrate how flexibility could serve as an alternative to traditional grid expansion in the years ahead [72].

In the 2025 iteration of the grid development plans, flexibility assessment is approached through approximation. The need for flexibility is assumed to be equal to the flexibility potential. Consequently, the total volume of calculated overloads (in MWh and MW) in the grid area of a DSO is treated as its flexibility potential. However, there is a lack of consistency in methodology: each DSO calculates these values differently, and few provide detailed explanations of their approach. As a result, flexibility estimates are not directly comparable across DSOs.

## Planning

In Denmark, the distribution grid planning process for DSOs is supported by the electrification model TEGRA (Technical and Economic Grid Reinforcement Analysis), developed by *Green Power Denmark*, a non-commercial organization representing over 1,500 members across the energy industry. Some DSOs use the tool for the calculations required in the grid development plans, such as projections of the future electric vehicle fleet, while others complement it with in-house calculation models or rely entirely on their own models, experience, and competencies.

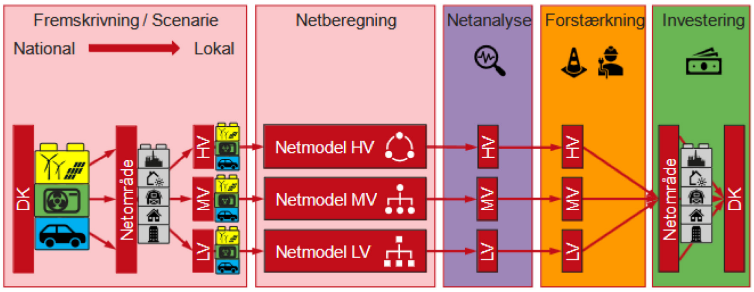


**Figure 6 – TEGRA schematic diagram, based on [72].**

The TEGRA model was developed in close collaboration with Danish DSOs and is used to create technical and economic planning scenarios for distribution grids undergoing rapid transformation due to the widespread adoption of electric vehicles, heat pumps, and variable renewable energy sources. The model follows five consecutive steps (Figure 6). First, the national renewable energy and decarbonisation targets are applied to the local grid area. For this, the number of households, characteristics of the grid area, and other relevant factors are considered to determine the share of national implementation targets that will be realized in each specific distribution grid area. In the second step, the impact of the energy transition is calculated for the LV, MV, and HV grids, respectively. The third step involves analysing the grid

| Denmark |
| --- |
| for deviations from operational limits. In the fourth step, the necessary grid reinforcements are calculated, and finally, the fifth step determines the corresponding investment needs.<br><br>There is no standardized simulation tool required to be used by all DSOs. However, a combination of DIgSILENT PowerFactory and GIS data is commonly used for grid modelling [73], often supplemented by in-house tools or contracted software. One example of the use of in-house tools is the DSO *N1 A/S*, which covers large areas of Jutland and has developed an image recognition algorithm to assess the type and condition of cable cabinets [74]. Another example for the use of contracted software is the DSO *NKE-Elnet A/S* in Næstved, which uses software from Utiligize for their investment plans [75].<br><br>*Radius Elnet A/S*, supplying electricity to around one million customers in the Copenhagen area, North Zealand, and parts of Central Zealand, notes in its latest development plan that the grid development plan does not fully reflect its internal planning processes, as these differ in structure from the regulator's template. *Radius Elnet*'s planning consists of two main components: a long-term assessment of resource needs and a tactical/operational plan for actual grid expansion. The long-term assessment focuses on ensuring access to capital, internal competencies, and agreements with external suppliers, and is only partially linked to specific projects. It is based on internal knowledge of the grid and forecasts of future demand. The second component focuses on planning specific grid projects, including asset replacement and grid expansion. This work relies on various IT tools and asset management systems developed over time. Radius also engages in ongoing dialogue with key stakeholders such as large customers, trade associations, and municipalities. This approach allows the DSO to estimate investment needs over a 10-year horizon, categorized by voltage level and by reinvestment versus new investment. However, it does not maintain a fixed pipeline of projects for the entire decade. *Radius* argues that committing to detailed 10-year project plans would risk inefficient investments and lost flexibility. Instead, it aims to align specific project planning as closely as possible with actual needs and timing [76]. |

### 2.3.3. Italy

**Table 9 – Transmission grid planning in Italy.**

| Italy |
| --- |
| **Guidelines** |
| In compliance with Article 36, Legislative Decree no. 93/11, as amended by Law no. 120/2020, Italian TSO Terna develops the National Transmission Grid Development Plan every two years, submitting it for approval to the Ministry for the Environment and Energy Security (MASE). The Plan is elaborated considering also the geographical areas involved, and the assessments |

**Italy**

made by the Italian Regulator, ARERA. Terna is also required to submit a report on the progress status of the Development Plan, in the years in which the Plan is not required.

As indicated in two fundamental guidelines for planning the development of the National Transmission Grid (NTG) i.e. Grid Code (Codice di Rete) and Transmission Infrastructure Concession (Concessione dell'infrastruttura di trasmissione), the activities included in the Development Plan aim at: 1) guaranteeing and improving the adequacy conditions of the NTG, ensuring efficient management of available generation capacity, with particular attention to the production maximization from RES, 2) maintaining the operating safety conditions of the electricity system, 3) increasing the reliability and economic efficiency of the transmission grid, 4) improving the quality and continuity of service and the resilience of the electricity system and 5) observing the environmental and landscape constraints of the areas where infrastructures are installed. Last point is particularly relevant since attention and sensitivity to the topic has increased in recent times.

## Planning

In the last years, Terna's planning methodologies focus on the following main actions:

- Grid upgrade through the installation of new land and submarine High Voltage Direct Current (HVDC) cable interconnections both in the Italian territory (e.g. Adriatic Link 1000MW-500kV, Tyrrhenian Link 1000MW-500kV submarine HVDC cable projects) and with neighbouring countries (e.g. "Italy-France" underground HVDC cable project 1200MW-320kV, "ELMED" submarine HVDC cable project between Italy and Tunisia 600MW-500kV).
- Grid upgrade through the conversion of HVAC lines in HVDC system with the main advantages of increasing the power transmitted and decreasing land authorizations to be obtained.
- Installation of new storage systems, considering that the new medium- to long-term energy scenario jointly defined by Terna envisages a requirement of about 72 GWh of installed capacity of storage systems by 2030 [77], in addition to the hydroelectric pumping that exists to date, to integrate the expected renewable generation.
- Develop new forecasting tools and algorithms for managing variability related to RES integration and electrification of consumption [78].

The above measures aim to increase electrical stability and capacity for grid control with a valuable impact also on heavy-duty mobility sector.

**Table 10 – Distribution grid planning in Italy.**

**Italy**

## Guidelines

In Italy, DSOs above 100,000 customers are required to submit a Grid Development Plan (NDP) every two years, with a 5-years horizon to the Italian Energy Regulator, ARERA. By March 31st of each odd-numbered year, the DSOs must elaborate the document for public consultation lasting 42 days, after which the Plan and any updates must be published by June 30th. Similarly, by March 31st of each even-numbered year, DSOs subject to the obligation to send the NDP must submit the 'Development Plan Monitoring Report' updated to December 31st of previous year. This last document is an update of planning activities from an economical perspective, always with a 5-years horizon plus the final balance of last previous year.

Recently, the Regulator published Resolution 521/2024/R/eel which outlines the index and the general characteristics of the new NDP, defining its structure, the accompanying documents and the elementary categories of interventions to be analysed. The recommendations included in the aforementioned documents are based on the one year-round table taken place between the 10 majors Italian DSOs held in 2024 supported by Politecnico di Milano.

The Plan should be developed in coordination with the TSO (i.e. Terna) and should consider the evolution of flexibility needs, demand-response services, potential risks of congestion, availability of storage assets, electricity generation assets connected to the distribution grid, etc. The Plan should also indicate what planned investments on the electricity grid are deemed to be required to connect new generation capacity and loads. The planning phase, during which anticipatory investments are identified, is based on a set of real and forecast data related to the grid that highlight the need for an intervention. Thanks to the analysis of real time electrical parameters of the assets, combining them with faults occurred on the asset and load's evolution in the past years, it is possible to identify the most critical assets in the grid that e.g. need to be replaced or the new assets that must be realized. In this manner, planned investments are characterized by a high level of maturity.

There is a set of drivers that are considered in the planning phase for an intervention to be included in the NDP; the investment must improve at least one of the following: 1) Increasing the Hosting Capacity or the "loadability" of the asset involved in the intervention (this driver tries to ensure that the grids are ready for the energy transition, in particular to accommodate new power production from renewables and to face increased consumption due to electrification); 2) Increasing the resilience of the asset under evaluation (e-g-, to face extreme weather events); 3) Reducing the reactive power or the voltage deviations with respect to the nominal thresholds; 4) Increasing the quality of service, reducing failure probability and/or asset's modernization for higher security during grid maintenance; 5) Increasing digitalization of the grid (telecommunication and monitoring systems); 6) Increasing the safety and security of the grid or reducing the environmental impact, e.g. for HV/MV transformers. Actions related to the

**Italy**

substitution of LV meters, post- fault maintenance and grid's modification requested by the final users are not considered in the NDP. The regulatory system needs to take into consideration the evaluation provided by the system operators with respect to the drivers that can be improved by the activities. The compliance with one or more of the drivers mentioned above can result in an action with low risk.

In addition, with the last update of the TIQD (i.e. Testo Integrato della regolazione output-based) through Resolution 617/2023/R/eel, in January 2024, ARERA has introduced a new incentive mechanism aimed at providing economic support to anticipatory investments that demonstrate a positive cost-benefit analysis, to improve the adequacy, resilience and security of the electricity distribution grid. This mechanism is at its first application, and it encourages the major DSOs to develop a cost-benefit analysis for the main activities included in their NDP. During 2024 a shared methodology for cost-benefit evaluation has been discussed among the 10 major Italian DSOs and submitted to ARERA, with the goal of obtaining a common procedure for the next regulatory years. ARERA published the outcome of such discussion on March 27th with Resolution 112/2025/R/eel.

## Planning

Planning methodologies differ between Italian DSOs. As described in the previous section "Guidelines", starting form 2025 each DSO with >100,000 PODs must describe planning criteria in its own NDP according to Resolution 521/2024/R/eel. Even though each DSO can use whichever tool they consider more appropriate to their peculiar needs, there are some drivers which should be considered in including measures in the NDP. These drivers are described in Resolution 521/2024/R/eel (see previous section "Guidelines").

Among major DSOs, Unareti identifies the specific asset to be included in the NDP using different methodologies depending on level of voltage and type of asset:

- HV/MV elements: Unareti identifies the activities to include in the NDP considering:
    - Asset saturation: load curves in standard operation of main elements (e.g. HV/MV transformer, MV line underneath the MV switchgear of the primary substation, MV/MV transformer and MV/LV transformer) are compared with a utilization ratio given by the type of asset, its redundancy and level of meshed grid connected. The ratio considered to date is 60% of the nominal size, in standard operating mode. This value is used as a limit beyond which it is necessary to evaluate a possible action to be included in the NDP.
    - Asset criticality: each asset is associated with criticality, necessary first to identify and then to prioritize activities to be included in NDP. This criticality is mainly based on the number of impacted users, energy not supplied and the asset historical failures.

**Italy**

- Ordinary and Extraordinary Maintenance Plans: the NDP also includes needs reported by Technical Maintenance Office, which draws up Ordinary and Extraordinary Maintenance Plans for the entire electricity system.
- Technical aspects: availability and aging of components, environmental impact disposal (e.g. absence of PCB for transformer) and operator safety (e.g. from "open" switchgear to "protected" one)

- MV lines: Unareti mainly bases the selection of actions for MV lines on off-line diagnostic. It is based on targeted groups of line sections to be analysed. This task is handled by an internal ad-hoc algorithm called Diamond, which has evolved from an "experience-driven" logic to a data-driven logic. Diamond is an advanced predictive maintenance tool developed to improve the reliability and efficiency of Milan's electricity grid. It uses advanced machine learning techniques to analyse large volumes of heterogeneous data, including cable characteristics (e.g. type of conductor and insultation), topological data (coming from the grid spatial model ArcMap), and data on faults and outages.
- LV lines: the identification of actions on LV lines strongly depends on element details that define the risk level and consequently planning priorities. In general, most actions included in the NDP are led by 1) New user connections based on forecasts of areas subjected to increase in power demand; 2) Requests from operating departments for renewal work due to evidence detected in site; 3) Concurrence with works on the MV electricity grid; 4) Any renewal plans assessed as necessary to massively renew portions of the grid following ad-hoc evaluation. Unforeseen needs, e.g. new LV user requests for connection or repair after fault, are managed through day-by-day activities.

### 2.3.4. Portugal

**Table 11 – Transmission grid planning in Portugal.**

**Portugal**

**Guidelines**

Transmission grid planning in Portugal is governed by national (*Entidade Reguladora dos Serviços Energéticos* – ERSE) and European regulations, including the National Energy and Climate Plan 2030 (PNEC 2030) and the Long-Term Carbon Neutrality Strategy 2050 (RNC 2050). These plans set renewable energy and decarbonization goals, guiding infrastructure development to achieve carbon neutrality by 2050.

The planning process focuses on a medium- to long-term vision, typically spanning over 10 years, to ensure the grid can accommodate future demand growth, renewable energy expansion, and technological advancements. Integration of renewable energy is a priority, with

**Portugal**

a focus on connecting wind, solar, and offshore wind sources to the grid while minimizing curtailment risks and ensuring system stability. Coordination between transmission and distribution systems is emphasized, with strong collaboration between REN (the TSO) and DSOs to manage distributed energy resources effectively and ensure bidirectional flows. Stakeholder engagement is also crucial, with public consultations involving policymakers, regulators (ERSE), utilities, and academia to ensure that the planning process aligns with national priorities and incorporates diverse perspectives. Technical standards are strictly adhered to, including N-1 security criteria, geospatial optimization for renewable siting, and compliance with grid codes for new generation connections. The primary tool for actual planning is the PDIRT-E (*Plano de Desenvolvimento e Investimento na Rede de Transporte de Eletricidade*), a 10-year development plan prepared by REN. The latest plan, PDIRT-E 2024–2034, allocates €1.69 billion for grid upgrades, focusing on the expansion of the 220 kV grid.

## Planning

Portugal's transmission planning actively supports its ambitious renewable energy targets. By 2034, the goal is to integrate approximately 23 GW of solar, 6 GW of onshore wind, and 1–2 GW of offshore wind capacity. Geospatial mapping identifies optimal zones for renewable projects based on resource availability and grid readiness.

As an example, in very urbanized areas, REN is converting overhead lines to underground circuits to reduce visual impact and improve reliability and building new substations in strategic locations to support regional demand growth through adherence to N-1 security criteria. To include RES more efficiently, grid planning includes strategies like constructing double circuit lines initially with one circuit, temporarily operating lines at lower voltage levels, and using phase-shift transformers to control grid flows

Flexibility is incorporated into the planning process through dynamic nodal capacity assessments, which provide regular updates on available grid capacity for new generation projects. Currently, a market-based procurement of system services is in place that involves contracts with generators to provide frequency control and balancing. Concerning financial mechanisms, ERSE oversees cost recovery through regulated tariffs, ensuring REN meets efficiency targets while maintaining financial sustainability.

**Table 12 – Distribution grid planning in Portugal.**

**Portugal**

## Guidelines

Every two years, DSOs collaborate with the TSO to create a five-year development and investment plan (PDIRD-E). This plan undergoes public consultation and is submitted to ERSE

**Portugal**

and the DGEG (Directorate-General for Energy and Geology) and requires government approval after parliament discussion.

The PDIRD-E must include technical characteristics of the distribution grid, supply safety monitoring reports, safety standards for grid planning, and requests for grid connection and capacity reinforcement. ERSE oversees the economic aspects of electricity distribution, setting tariffs for grid usage and determining operator revenues. Distribution grids operate under concession agreements, with different terms for various voltage levels (HV and MV grids have a 35-year concession, while LV grids have municipal concessions up to 20 years). Environmental considerations are also integral to the planning process. The construction of certain distribution infrastructure may require environmental impact assessments, especially for power lines and substations above specific voltage and size thresholds. Grid capacity calculation is another critical aspect, involving nodal capacity calculations that comply with security criteria to accommodate new generation.

## Planning

E-Redes, the largest DSO in Portugal, employs a structured flexibility planning methodology based on a techno-economic approach that consists of three main programs [79]:

- Grid development - Addressing constraints and identifying opportunities (e.g., loss reduction, minimization of non-distributed energy).
- Asset renewal and rehabilitation – Managing aging infrastructure through risk assessment and asset health indices.
- Quality of service – Ensuring system reliability and compliance with performance-based incentives.

E-Redes systematically identifies grid constraints and opportunities by employing key planning metrics that evaluate service reliability and efficiency, such as energy not supplied (ENS), loss reduction and SAIDI. The latter has become the primary indicator for assessing service continuity, replacing SAIFI as the priority metric in reliability evaluation. Additionally, regulatory remuneration models are considered to align investments with service quality improvements (usually applied on the worst-performing 5% of delivery points), guaranteeing a balance between financial viability and system performance. If service quality exceeds defined regulatory targets, additional compensation is provided until a certain limit, and vice-versa if service quality is below the threshold. Currently, the Copperleaf software is being used for project planning, prioritization and optimization.

Technical planning studies rely on digital simulations of the grids using specific software. At E-REDES, the DPlan – Distribution Planning tool is used for calculations. In the past, the distribution grid's function was mainly to deliver energy to consumption points, which were characterized by load diagrams, typically marked by peak load and load factors. Due to the

**Portugal**

increasing penetration of distributed generation in the distribution grid, the DSO began simulating various extreme and intermediate load regimes based on actual generation and consumption data. To address uncertainties in generation and consumption regimes, E-REDES, in collaboration with the national scientific community, developed probabilistic planning methodologies to increase the reliability of its forecasts and ensure that investments align with the development needs of the distribution grid. These methods were integrated into the DPlan tool. Using real consumption/production diagrams and data analytics tools such as density-based clustering (DBSCAN) and hierarchical clustering, the distribution grid's installations were segmented by typical daily diagrams, categorized by weekday (workday, Saturday, Sunday) and season (winter, spring, summer, autumn). From these typified diagrams and historical consumption/production data, the intra-daily dynamics of load/generation at each installation type were characterized using probability transition matrices (Markov Chains). This methodology was applied across the distribution grid's installations, including substations, transformer stations, producers, and delivery points at different voltage levels. Simulated daily load diagrams are generated based on transition probabilities for each typified day. There is a regulatory incentive to prioritize investments on the worst-performing 5% of MV delivery points in Portugal.

The economic evaluation of studied alternatives is carried out using the INVESTE tool, which calculates the total costs, including material and labour costs, direct charges, and financial costs. The benefits of projects are calculated based on various physical quantities, such as the reduction in Joule losses and improvements in service quality when compared to a baseline scenario, and these benefits are quantified in monetary terms. For the economic evaluation of investment projects, benefits such as the elimination of overloads and non-compliant voltage drops are considered as unserved energy (the energy that would be distributed with overloads or below the regulatory voltage level). The economic evaluations also include sensitivity analysis regarding demand evolution, conducted for different demand scenarios using indicators like benefit/cost ratio (B/C), Net Present Value (NPV), Internal Rate of Return (IRR), and Total Return Index (TRI).

In line with Decree-Law No. 15/2022, which transposes EU Directive 2019/944, the DSO has been working to incorporate alternatives to investment based on market flexibility services into grid planning (Figure 7). This includes the development of flexibility requirements to replace traditional grid investment, such as contracting market flexibility services for distributed resources.

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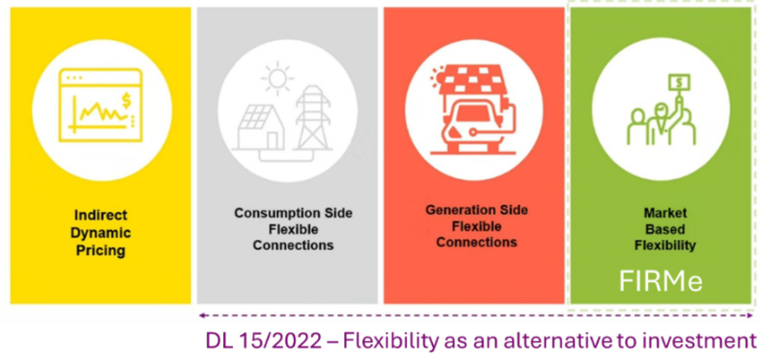


**Figure 7 – Flexibility approaches mapped by E-Redes.**

In anticipation of legal requirements, E-REDES launched the FIRMe project in late 2022 to conceptualize and explore efficient flexibility solutions and stimulate the market by raising awareness among market agents and promoting participation in the new local flexibility market. Flexibility alternatives are developed based on two pillars: using data from smart grids to create realistic synthetic diagrams and developing probabilistic analysis methodologies for grid planning. This analysis identifies the flexibility needs of loads, describing the market contracting requirements, such as maximum power needed to eliminate constraints, activation time windows, installations, and voltage levels capable of resolving constraints. At E-REDES, the market-based flexibility is divided in three main approaches: 1) Secure: Addresses existing or expected constraints under normal operating conditions; 2) Restore: Used in contingency situations where flexibility supports grid restoration and 3) Dynamic: Applied in planned asset unavailability scenarios.

Despite the challenges of flexibility alternatives, a planning methodology combining supply security risk management and flexibility has been proposed. Investments traditionally ensure security by meeting peak demand, which is often infrequent. To mitigate this, the DSO proposes delaying investments that meet consumption needs 95% of the time and managing the remaining risk with flexibility services, in the locations in which FIRMe is being deployed.

As an operational example of a dynamic use case, could be the overload of a transformer caused by the unavailability of another unit. The solution involves MV curtailment of a producer with a forecasted curtailed power and energy. The value of this flexibility is determined by the cost of deploying a mobile substation to mitigate the overload during that period.

### 2.3.5. Slovenia

**Table 13 – Transmission grid planning in Slovenia.**

**Slovenia**

**Guidelines**

The planning of Slovenia's electricity transmission grid is guided by national and European regulatory frameworks, with a strong emphasis on system reliability, energy transition, and

**Slovenia**

integration of renewable energy sources. Transmission planning is primarily governed by documents such as the Integrated National Energy and Climate Plan (NEPN) and the long-term Transmission Network Development Plan issued by the Slovenian transmission system operator, ELES.

Slovenia's NEPN outlines the country's energy strategy through 2030 and sets clear targets for decarbonization, increased renewable energy integration, and enhanced grid flexibility. Transmission planning plays a crucial role in supporting these targets by ensuring sufficient capacity for cross-border flows, balancing variability from renewables, and enabling electrification of various sectors.

ELES's Transmission Network Development Plan (2023–2032) provides a more technical and operational roadmap, identifying required infrastructure investments such as: 1) construction of new high-voltage lines and substations, 2) modernization of existing corridors, 3) improved interconnection with neighbouring countries, 4) implementation of digital and smart grid components, and 5) facilitation of energy storage and system flexibility.

From a technical perspective, transmission grid planning in Slovenia adheres to internationally recognized reliability criteria, including the N and N-1 security standards. Advanced power flow studies, contingency simulations, and stability analyses are used to validate the robustness of proposed developments.

In terms of regulatory oversight, transmission investments are subject to review and approval processes at both national and EU levels. Projects must demonstrate alignment with strategic goals and cost-efficiency criteria. The Slovenian Energy Agency ensures that planning activities are consistent with broader policy objectives that adequate financial mechanisms are in place.

**Planning**

ELES embeds network planning in a cascading corporate cycle that begins with the strategic plan, passes through the network-development and investment plans into the annual budget, and closes with a formal performance review. Demand-and-generation scenarios are projected to 2034—anchored by a 2050 vision—and processed in a modelling chain where bespoke market simulations are coupled with AC power-flow and contingency studies. These analyses rely on PSS/E and DIgSILENT PowerFactory for steady-state and dynamic assessments, augmented by proprietary cross-border market models and Monte-Carlo runs wherever renewable-output uncertainty is material. Candidate projects must clear a filter that weighs net socio-economic benefit, potential RES-curtailment reduction, security-of-supply gains, adequacy metrics such as LOLE and ENS, and alignment with EU Green Deal benchmarks.

**Table 14 – Distribution grid planning in Slovenia.**

**Slovenia**

## Guidelines

The modernization of Slovenia's electricity distribution grid is a cornerstone of the country's transition to a sustainable, low-carbon energy system. The *Electricity Distribution Network Development Plan 2023–2032*, published by SODO d.o.o., outlines strategic priorities including infrastructure renewal, capacity expansion, and enhanced operational reliability to support decarbonization and the increasing electrification of transport and heating sectors.

This transformation is closely aligned with national objectives set out in the NEPN, which defines Slovenia's roadmap toward 2030 targets in renewable energy integration, energy efficiency, and greenhouse gas reduction. The NEPN emphasizes increased distributed generation, advanced grid flexibility, and consumer participation in energy markets.

The modernization process is governed by the legal and regulatory framework laid out in the *Energy Act (Energetski zakon – EZ-1)*, which mandates the development and operation of the electricity system in line with European Union directives and national energy goals.

The technical operation of Slovenia's distribution grid is defined by the *System Operating Instructions (Sistemska obratovalna navodila)* and accompanying studies by the Elektroinštitut Milan Vidmar (EIMV). These documents establish key engineering and planning parameters essential for grid stability and development. Core technical guidelines include:

- Voltage and Current Constraints: Definitions of voltage drop thresholds, current load capacities, and reference impedance levels necessary for safe and efficient grid operation.
- Capacity Planning: Methodologies for short- and long-term planning to meet current and anticipated electricity demand, especially considering electrification and decentralization trends.
- Integration of Distributed Energy Resources: Criteria and processes for incorporating renewable energy sources, electric vehicles (EVs), and energy storage systems into the distribution grid, including reverse power flows and grid balancing mechanisms.

These guidelines ensure that Slovenia's distribution system remains resilient, flexible, and capable of supporting the energy transition while adhering to national and EU-level strategic goals.

## Planning

In Slovenia, the planning of electricity distribution grids, particularly LV systems, is based on nationally coordinated technical guidelines. These ensure standardized quality of service, long-term reliability, and regulatory compliance across all DSOs. Planning practices are anchored in

**Slovenia**

methodologies developed by the EIMV, covering both technical and economic aspects of grid development.

Planning today must address evolving energy usage patterns, driven by electrification of heating and transport, increased energy efficiency, and the rapid deployment of DERs, such as photovoltaic systems and battery storage. Grid designs must be resilient and adaptable over a lifespan exceeding 30 years, allowing for future growth and technology shifts.

The key technical planning criteria involves three main factors, which are presented below:

- Voltage Drop Limits: Voltage drop between the transformer station, and the furthest customer is a fundamental constraint. These limits preserve voltage quality and help avoid undervoltage conditions at customer premises.
  - ≤ 5% for newly designed grids (target value).
  - ≤ 7.5% for grid extensions or upgrades.
  - 10% is not permissible under normal operating conditions.
- Reference Impedance: The loop impedance from the transformer to the consumer must not exceed a reference value ($Z_{ref} = 0.4 + j0.25\ \Omega$). This limit ensures that electrical appliances receive voltage within the acceptable quality range and is a fixed design constraint independent of load levels.
- Conductor Loading Limits: Conductor currents must not exceed 80% of their rated thermal capacity. This ensures long-term safety, avoids overheating, and provides a buffer for future load increases. Typical conductor sizes and corresponding current-carrying capacities include: 1) 35 mm² Al: approx. 60 A; 2) 70 mm² Al: approx. 100 A; 3) 150 mm² Al: approx. 150 A and 4) 240 mm² Al: approx. 200 A. These values are used in planning to determine suitable conductor types based on expected load and feeder length.

When estimating electrical loads in distribution grid planning, coincidence factors—also known as simultaneity factors—are applied to account for the fact that consumers do not reach their peak consumption simultaneously. For example, although 100 individual households may each have a nominal load of 10 kW, the aggregated planning load would typically be around 300 kW rather than the full 1000 kW. The coincidence factor depends on the number and type of consumers and decreases as the group size increases, reflecting the diversified nature of load behaviour.

Standardized customer load profiles are used to facilitate planning and system design. Individual residential households are typically assigned a load of 10 kW, while units in multi-family residential buildings are assigned 5 kW. Large residential or commercial consumers are considered based on 80% of their contracted connection capacity. These assumptions

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streamline the calculation of expected loads on grid sections and are used to determine appropriate conductor sizing and protective device settings.

In regions with a high concentration of electric heat pumps, such as newly developed residential areas, the expected household loads are often doubled to account for increased energy consumption during colder months. This adjustment ensures that the grid is adequately dimensioned for the more intensive and seasonal nature of heating loads.

Given the limited availability of real-time monitoring data in low-voltage distribution grids - particularly concerning voltage asymmetries and dynamic load patterns - planners rely on conservative design assumptions. This cautious approach helps to ensure system reliability and robustness under both typical and exceptional operating conditions.

In modern urban and suburban settings, new LV and MV grids are almost exclusively built as underground systems. Cables are typically routed under public roadways, which simplifies obtaining legal consents and minimizes disruption to landowners. While MV grids are increasingly underground, some overhead lines remain, especially in rural or remote areas where undergrounding is less practical or cost-effective.

All new grid projects are reviewed by the internal Investment Committee of the DSO. This body determines which investments are essential and which can be postponed. Approved projects are entered into the JIRA system, which tracks planned and completed works, ensuring alignment between technical priorities and financial planning.

Under Slovenia’s regulatory framework, DSOs receive funding based on their investment plans and operational performance. A well-maintained and proactively upgraded grid is more likely to receive increased funding allocations, incentivizing long-term planning and grid modernization in line with national energy goals.

### 2.3.6. Comparative overview of the country-specific approaches

In all five countries - Albania, Denmark, Italy, Portugal, and Slovenia - transmission grid planning is guided by national and European energy and climate frameworks, with a shared commitment to achieving carbon neutrality by 2050. TSOs develop medium- to long-term development plans, typically updated every two years or over a 10-year horizon, that prioritize the integration of renewable energy sources, grid reliability, and system flexibility.

These plans are tailored to national contexts: Albania and Portugal emphasize phased infrastructure deployment and geospatial tools to optimize renewable energy zones; Denmark focuses on large-scale 400 kV grid expansions to accommodate offshore wind; Italy leads in cross-border HVDC interconnections and storage integration; and Slovenia combines corridor modernization with digital grid components and cross-border capacity.

Flexibility is addressed through a variety of mechanisms. For instance, Albania and Portugal conduct dynamic nodal capacity assessments and procure ancillary services through market-based mechanisms. Italy is investing in large-scale storage (targeting 72 GWh by 2030) and advanced forecasting tools, while Denmark offers conditional connection agreements to manage capacity constraints.

Planning processes consistently involve stakeholder engagement and coordination between TSOs and DSOs, ensuring alignment with national priorities and local needs. All countries adhere to strict technical standards, particularly the N-1 security criterion, and rely on advanced modelling tools such as contingency simulations and power flow analyses to validate system robustness.

Financial sustainability is ensured through regulated tariff frameworks overseen by national energy regulators (e.g., ERE, ERSE, Forsyningstilsynet, ARERA, and the Slovenian Energy Agency), which guarantee cost recovery, incentivize efficiency, and support long-term investment planning.

Regarding the planning of the distribution grid, all five countries require DSOs to prepare forward-looking development plans, typically with a five- to ten-year horizon, and most follow a biennial update cycle. These plans are generally submitted to national energy regulators and often involve public consultation, ensuring transparency and stakeholder engagement. All five countries are aligned in their efforts to modernize distribution system planning. They increasingly rely on data-driven tools, forecasting methods, and digital platforms to enhance decision-making. A shared priority across the five countries is the integration of distributed energy resources (such as solar PV, storage, and demand response), into their planning frameworks.

To better understand how these planning principles are being implemented across Europe, it is useful to look at concrete examples from DSOs. The DSO Observatory 2024 – Unlocking Flexibility in Europe [80], published by the Joint Research Centre of the European Commission, offers a comprehensive overview of how DSOs across the EU are already adapting to the energy transition. Drawing on data from 68 DSOs in 26 Member States, this observatory includes some insights from the DSOs of Denmark, Italy, Portugal and Slovenia and provides information on what has been achieved regarding grid development and what remains to be planned and developed.

All four countries have achieved near-complete smart meter deployment, having enabled digitalized grid operations and laying the groundwork for flexibility services. While Denmark and Portugal have already implemented dynamic tariff models, Slovenia introduced a new power-based time-of-use tariff in 2024, and Italy is leveraging digital tools to support local flexibility markets [80].

Italy and Portugal are leading with operational local flexibility markets, while Denmark promotes flexibility through market mechanisms and stakeholder engagement. Slovenia is still in the early stages but is aligning with EU directives to prepare for future implementation. Regulatory models vary, from Portugal's TOTEX-based revenue cap to Italy's hybrid model and Denmark and Slovenia's performance-based schemes [80].

All four countries require DSOs to prepare grid development plans, though the scope and content differ. Portugal already includes flexibility and demand-side measures, while Italy and Slovenia are expanding their planning frameworks to reflect these priorities. Denmark's planning is more decentralized, with DSOs using a mix of national and in-house tools [80]. Despite differences in formality (such as Denmark's non-binding plans versus Italy's and Portugal's structured regulatory obligations), all countries incorporate technical standards, environmental considerations, and alignment with national or EU energy strategies.

In Albania, planning is anchored in annual updates focused on reducing losses and modernizing aging infrastructure, supported by emerging digital tools and pilot flexibility projects. Denmark emphasizes decentralized and adaptive planning, using scenario-based models like TEGRA and a variety of in-house tools tailored to local needs. Italy follows a regulation-driven approach with voltage-specific methodologies and predictive maintenance systems, while also incorporating flexibility and cost-benefit analysis into its planning. Portugal stands out for its use of probabilistic planning and advanced simulation tools, integrating flexibility through market-based mechanisms like the FIRMe project. Slovenia, meanwhile, relies on nationally standardized technical criteria and conservative design assumptions to ensure long-term reliability, particularly in LV grids, with funding tied to performance and investment quality.

In essence, while the planning processes vary in structure and emphasis, they converge on key priorities: ensuring grid reliability, enabling renewable integration, supporting electrification, and fostering transparency and accountability in the path toward a more sustainable and flexible grid.

# 3. GRID CAPACITY OPTIMIZATION

## 3.1. Case study classification

This subchapter introduces a series of real-world case studies that serve as a foundation for simulation-based analysis in the subsequent task 4.3 – Development and Validation of Grid models. These case studies represent a diverse cross-section of EV charging scenarios, each selected to reflect unique combinations of grid conditions, charging behaviours, and planning challenges that could be replicable in each of the project's demonstration sites.

Each case is characterized by key parameters such as voltage level (LV, MV, HV), location type (urban, rural, industrial, commercial), and the nature of the charging infrastructure (residential, public fast charging, fleet depots, etc.). This classification allows for a systematic comparison of use cases and helps identify common patterns and outliers in terms of grid impact and flexibility potential.

The case studies (listed in Table 15) span a wide range of operational contexts—from residential condominiums and dense urban neighbourhoods to high-power highway chargers and port-based vessel charging. This diversity ensures that the simulation framework can capture the full spectrum of technical and spatial challenges associated with EV integration.

These case studies are directly linked to the AHEAD project, specifically to the use cases defined under T4.1 – Scenario and Use Case Formulation, as well as the demonstration sites where this use cases will be tested. While most of the grid planning case studies are aligned with the defined use cases, some have been included to ensure a broader representation of scenarios, even if they do not correspond to a specific use case. Additionally, these grid planning case studies may involve different levels of magnitude concerning the number of participating EVs compared to the demonstration sites. Nevertheless, the core grid planning principles to be implemented remain consistent.

The main goal is to have targeted simulations that will assess grid constraints, evaluate mitigation strategies, and inform grid planning decisions. Moreover, each case study is linked to specific stakeholders, including DSOs, TSOs, municipalities, fleet operators, and infrastructure providers, highlighting the multi-actor nature of grid planning in the EV ecosystem.

**Table 15 – Representative EV charging case studies.**

| ID | Name | UC | Voltage level | Description | Location Type | Demo. | Stakeholders | EV Charging Type | Typical Scenario |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential Condominiums | 2 | LV | Impact of simultaneous EV charging in residential condominiums, focusing on peak load conditions in evening hours. | Urban residential areas | PT1 residential block | DSOs, condominium associations, EV owners | Level 2 residential chargers, potentially clustered within a condominium | # 15 - 40 EVs actively charging<br># 3,7 - 11 kW<br># Evening to overnight 6 PM - 6 AM<br># ~5h avg charging time |
| 2 | High-Power Chargers Connected to Transmission Line | 7 | MV/ HV | Direct high-power EV charging stations connected to the transmission grid, analyzing the effects on grid stability and congestion. | Highways or major transportation corridors. | DK1 countryside | TSOs, highway authorities, DSOs, CPOs | High-power chargers (150kW+), suitable for fast charging at rest stops. | # 5 - 20 EVs actively charging<br># 150 - 350 kW<br># Daytime Hours (10 AM – 6 PM) - High utilization from commercial and private EVs on long-distance routes<br>Nighttime Hours (8 PM–4 AM): Common for heavy-duty trucks<br># 15 - 30 minutes (light EVs), 30 - 90 minutes for HDVs |
| 3 | Depot Charging for Heavy-Duty/ Passenger Fleets | 4/6 | MV/ HV | Charging infrastructure designed to support overnight or scheduled charging for buses or logistics fleets, ensuring operational continuity. These facilities cater to centralized fleet charging | Industrial areas, urban outskirts, or large depots with space for multiple charging points. | SI2 Kranj parking lot AND IT1 A2A primary | DSOs, TSOs, EV fleet operators, logistics & public transportation companies, municipalities, and depot managers | High-power chargers (50–500 kW) for buses and heavy-duty EVs, with possible overnight slow charging | # 20–100 EVs charging<br># 50–500 kW per vehicle<br># Mostly overnight (8 PM–6 AM), with some cases with daytime charging<br># ~4–8 hours per session for overnight charging, 30 – 60 minutes for daytime charging. |
| 4 | Charging Hubs in Commercial Zones | - | LV/ MV | Charging hubs in commercial zones provide high-power charging infrastructure for a variety of EVs | Commercial zones in urban areas, shopping centers, office complexes, transportation hubs (airports, train stations). | - | DSOs, TSOs, CPOs, EV fleet operators, municipalities, commercial property owners, businesses, and retail centers. | Public chargers (22 kW–150 kW), supporting a variety of vehicle types including personal EVs, taxis, delivery vehicles, and fleets. | # 10–30 EVs charging<br># 22–150 kW per vehicle<br># Daytime hours (9 AM–6 PM)<br># ~30 min –2h per session. |

| ID | Name | UC | Voltage level | Description | Location Type | Demo. | Stakeholders | EV Charging Type | Typical Scenario |
|---|---|---|---|---|---|---|---|---|---|
| 5 | Rural and Seasonal Charging Areas | 2 | LV/MV | EV charging infrastructure in rural areas and seasonal tourism hotspots. These areas may lack robust grid infrastructure and experience fluctuating demand due to tourism peaks. | Rural areas, seasonal tourism hotspots, rest areas, and remote regions with low grid development or infrastructure | DK1 countryside | DSOs, EV fleet operators, municipalities, tourism operators, and possibly TSOs for larger grid impacts. | Public chargers, ranging from Level 2 chargers to High-Power chargers for fast charging, depending on the location and usage requirements. | # 5–20 EVs charging<br># 3,7–150 kW per vehicle<br># Evening to overnight (6 PM–6 PM) for slow charging, daytime charging for seasonal demand<br># ~30 min –3h per session (depending on the charger power) |
| 6 | EV Charging in Dense Urban Neighborhoods | 9 | LV | This use case focuses on providing curbside charging solutions for residential EV owners in dense urban neighborhoods. | Dense urban residential neighborhoods, particularly in cities where space is limited, and curbside parking is common. Charging may also be integrated into commercial areas or mixed-use zones with high foot traffic. | PT1 public downtown | DSOs, municipalities, residential EV owners, EV infrastructure providers, local authorities for zoning and permitting, and urban planners. | Residential chargers (typically Level 2, 3.7 kW to 22 kW) installed along curbs, providing convenient access for EV owners without requiring private parking. Some locations may include shared very-high-power public chargers (more than 150 kW) in high-traffic urban areas. | # 5–30 EVs charging<br># 3,7–350 kW per vehicle<br># Workday, evening to overnight (6 PM–6 AM)<br># ~30 min –1h per session in commercial areas, 4-8 hours for overnight residential users |
| 7 | Industrial Light Fleet Charging | 5 | MV | Charging infrastructure needed for light EV fleets operating in industrial settings, such as service fleets, delivery vehicles, or small transport fleets | Industrial zones, logistics centers, fleet depots, and other commercial facilities that host fleets of light EVs | PT2 Lisbon parking lot | EV fleet operators, DSOs, municipalities, infrastructure providers, industrial facility owners, and potentially EV manufacturers. | High-power chargers (e.g., Level 3 chargers, 50 kW or more), often used for fleet vehicles in a centralized depot, fleet charging stations, or dedicated industrial chargers with fast-charging capabilities to minimize downtime. | # 10–50 EVs charging<br># 22–150 kW per vehicle<br># Overnight (8 PM–6 PM), but it could also be scheduled during breaks or downtime<br># ~30 min –1h per session for light fleets with smaller batteries, 4-8 hours for overnight charging |

| ID | Name | UC | Voltage level | Description | Location Type | Demo. | Stakeholders | EV Charging Type | Typical Scenario |
|---|---|---|---|---|---|---|---|---|---|
| 8 | Residential EV Charging | 2 | LV | Residential EV Charging involves the installation of chargers at homes, allowing EV owners to charge their vehicles from the grid | Residential areas, including individual houses and apartment buildings | PT1 residential block | DSOs, EV owners, municipalities, electric utilities, charging infrastructure providers, EV manufacturers. | Residential chargers (Level 2 chargers), installed in individual homes or apartments. | # 1–3 EVs charging<br># 3,7–11 kW per vehicle<br># Overnight (6 PM–6 AM)<br># ~4-8 hours for overnight charging |
| 9 | Commercial Building EV Charging for Fleet and Employees | 5 | LV/MV | Charging fleets of electric vehicles used by businesses (e.g., delivery trucks, service vehicles) and providing employee charging for personal vehicles | Commercial zones, including office buildings, corporate campuses, parking lots, and industrial facilities. | DK2 DTU-Risø campus | EV fleet operators, employees, DSOs, municipalities, charging infrastructure providers, energy managers, building owners, EV manufacturers, TSOs | Employee chargers (Level 2 chargers, typically 3.7 kW to 22 kW) | # 20–50 EVs charging<br># 3,7–22 kW per vehicle<br># Working hours (9 AM–6 PM)<br># ~3-6 hours for workday charging |
| 10 | Vessel Charging at Ports | 4/8 | MV/ HV | Charging infrastructure at ports for vessels, such as electric ferries or ships using onshore power | Ports, harbors, and ferry terminals | PT1 public downtown | DSOs, TSOs, Port authorities, Vessel operators, Local municipalities, Utility companies | High-Power EV Chargers | # 1–10 vessels charging<br># 150kW–10MW per vessel<br># Time-of-use depend on a schedule<br># ~1-24 hour |

## 3.2. Grid constraints and flexibility opportunities

The variability in charging demand, driven by user behaviour, charger type, and location—can lead to a range of technical challenges that stress the distribution and transmission grids. This subchapter explores the grid constraints identified across the selected case studies and highlights the flexibility opportunities that can be leveraged to mitigate these impacts.

Each case study presents a unique combination of grid constraints, including transformer overloading, voltage drops, feeder congestion, harmonic distortion, and reverse power flow. These constraints vary in severity depending on the voltage level, spatial context, and charging profile. For instance, dense urban neighbourhoods may face transformer saturation due to clustered residential charging, while rural or seasonal hotspots may experience voltage instability due to long feeders and fluctuating demand.

To address these challenges, the case studies also incorporate a range of flexibility services and mitigation strategies. These include demand response, load shifting, vehicle-to-grid integration, battery energy storage systems, and spatial planning. The effectiveness of these solutions depends on the local grid configuration, regulatory environment, and stakeholder coordination.

This subchapter systematically maps the identified constraints to their corresponding mitigation strategies, providing a foundation for simulation-based evaluation in later tasks. By understanding where and how flexibility can be applied, grid planning can design more resilient and adaptive grid infrastructures that support the growing demand for EVs.

To systematically evaluate the technical challenges and planning requirements related to EV charging infrastructure, each case study in this deliverable applies a standardized ranking system for both grid constraints and corresponding mitigation solutions. The core principle is that a constraint categorized at a certain level can be addressed by a solution of the same level. This structured approach ensures consistency across diverse scenarios, enabling clearer comparisons and supporting effective prioritization in planning and simulation activities.

Grid constraints are ranked based on their expected severity and potential impact on the grid under the conditions described in each case study. Mitigation strategies are ranked according to the scale, complexity, and resource intensity required to address the identified constraints. This ranking helps determine the level of intervention needed and supports cost-benefit analysis in planning decisions. The ranking scale is defined as follows (Table 16):

**Table 16 – Ranking of grid constraints and mitigation strategies by impact.**

| Constraints | Mitigations |
|---|---|
| **Low Impact (1)** | |
| **Constraints** | **Mitigations** |
| The constraint is unlikely to cause operational issues under normal conditions. The existing grid infrastructure is generally sufficient to accommodate the charging demand without significant intervention. | Involves simple, low-cost, or operational measures such as smart charging, basic load management, or minor adjustments to charging schedules. |
| **Moderate Impact (2)** | |
| **Constraints** | **Mitigations** |
| The constraint may arise under specific conditions, such as peak charging periods or high EV penetration. It may require monitoring or moderate mitigation measures (e.g. peak shaving) to maintain grid stability and performance. | Requires intermediate interventions, which may include infrastructure reinforcements, deployment of reactive power compensation, or implementation of demand response programs. |
| **High Impact (3)** | |
| **Constraints** | **Mitigations** |
| The constraint is expected to pose a significant challenge, potentially leading to equipment overloading, voltage violations, or service disruptions. It may require proactive planning and potentially large-scale mitigation. | Entails significant investment or system redesign, such as transformer or substation upgrades, deployment of battery energy storage systems (BESS), or spatial reconfiguration of charging infrastructure. |

Building on this standardized ranking framework, Table 17 illustrates the specific grid constraints identified across the different case studies. These constraints were selected based on their relevance in EV-dense environments, where charging demand can significantly alter power flow dynamics and stress existing infrastructure

**Table 17 – Description of key grid constraints relevant to EV integration.**

| Constraints | Description |
|---|---|
| **Transformer overloading** | Transformer overloading occurs when the power demand exceeds the rated capacity of the transformer, leading to excessive heat generation and accelerated insulation aging. In EV charging scenarios—especially in residential clusters or fleet depots—simultaneous charging can push transformers beyond their thermal limits. This not only reduces transformer lifespan but also increases the risk of failure and voltage instability [81]. |
| **Voltage Drops** | Voltage drops occur when the voltage at the end of a feeder or distribution line falls below acceptable limits due to high current flow. In EV charging, especially at the LV level, clustered charging loads can cause significant voltage sags, affecting both EV performance and other connected loads. This is particularly critical in rural or long-feeder grids [82]. |
| **Feeder/Line Overloading** | Feeder overloading results from excessive current through distribution lines, leading to thermal stress and potential damage to cables and protective devices. High-power chargers (e.g., 150–350 kW) or simultaneous charging events can cause feeders to exceed their ampacity, necessitating reinforcement or reconfiguration of the grid [83]. |
| **Harmonic Distortion** | Fast chargers and power electronics used in EV infrastructure introduce non-linear loads, which generate harmonic currents. These harmonics distort the voltage waveform, reduce power quality, and can interfere with sensitive equipment. Harmonic distortion also |

| Constraints | Description |
|---|---|
| | increases losses and heating in transformers and cables, compounding other grid issues [84]. |
| **Phase Imbalances** | In three-phase systems, uneven distribution of single-phase EV chargers can lead to phase imbalance. This causes neutral conductor overloading, voltage unbalance, and increased losses. Phase imbalance is especially problematic in residential areas where chargers are often connected asymmetrically [85]. |
| **Reverse Power Flow** | Reverse power flow occurs when distributed energy resources (DERs) or bidirectional EV chargers (e.g., V2G) inject power back into the grid. While beneficial for flexibility, this can disrupt traditional power flow patterns, confuse protection schemes, and overload upstream equipment [86]. |
| **Frequency Stability** | High penetration of EVs, particularly when combined with renewable energy sources, can reduce system inertia. This makes the grid more sensitive to frequency deviations. While this is more relevant at the transmission level, large-scale fast charging or V2G operations can contribute to frequency instability if not properly managed [87]. |
| **Substation Overloading** | Substations may become bottlenecks when multiple feeders experience simultaneous high demand from EV charging. This is especially relevant in urban or commercial hubs with dense charging infrastructure. Overloading substations can lead to cascading failures or require costly upgrades [88]. |

By evaluating each case study against these constraints, planners can identify high-risk scenarios and design targeted mitigation strategies. To address these constraints, a range of mitigation strategies have been identified and ranked similarly across the case studies. These strategies vary in complexity, cost, and effectiveness, and are selected based on the specific grid conditions and charging profiles of each scenario. Table 18 outlines the key mitigation measures considered, explaining their technical function and relevance.

**Table 18 – Description of key grid mitigation strategies relevant to EV integration.**

| Mitigation | Description |
|---|---|
| **Infrastructure Upgrades** | Upgrading grid infrastructure—such as transformers, feeders, and substations—is a direct and often necessary response to capacity-related constraints like overloading and voltage drops. These upgrades increase the physical capacity of the grid to accommodate higher loads from EV charging [89]. |
| **Load Management** | Load management involves shifting or modulating EV charging demand to avoid peak periods and reduce stress on the grid. This includes time-of-use pricing, scheduled charging, and dynamic load control [90], [91], [92]. |
| **Voltage Control** | Voltage control strategies stabilize voltage levels across the grid using devices such as on-load tap changers, voltage regulators, and reactive power compensation (e.g., capacitors, static VAR compensators) [93]. |
| **Battery Energy Storage Systems** | BESS can absorb excess demand during peak charging periods and discharge during off-peak times, effectively flattening the load curve. They also provide ancillary services such as frequency regulation and voltage support [94]. |

| Mitigation | Description |
|---|---|
| **Renewable Energy Integration** | Integrating on-site renewable energy sources, such as solar PV, reduces the net load on the grid and supports local energy autonomy. When combined with BESS, RES can provide a sustainable and resilient charging solution [95], [96]. |
| **Vehicle-to-Everything Management** | V2X technologies enable bidirectional power flow, allowing EVs to discharge energy back to the grid or to buildings. This can support peak shaving, frequency regulation, and emergency backup [97]. |
| **Spatial Planning** | Strategic placement of charging infrastructure can reduce the need for extensive grid reinforcement. By co-locating chargers in areas with available capacity or near substations, planners can optimize grid utilization [98]. |

Each mitigation strategy addresses different technical challenges of EV integration in its own way. Although their selection and prioritization involve some subjectivity, they are based on how well each strategy aligns with specific grid conditions, stakeholder goals, and planning timeframes. As an example, a level 3 grid constraint can be solved through a level 3 mitigation measure for a specific grid planning use case. The dual-ranking between constraints and mitigations is depicted in Table 19.

**Table 19 – Dual-ranking matrix of grid constraints and mitigation strategies across case studies.**

| Case study ID | Name | Grid constraints | | | | | | | | Mitigation solutions | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Transformer Overloading | Voltage Drops | Feeder/ Line overloading | Harmonic distortion | Phase Imbalances | Reverse Power Flow | Frequency Stability | Substation Overloading | Infrastructure Upgrades | Load Management | Voltage Control | BESS | RES Integration | V2X Management | Spatial Planning |
| #1 | Residential Condominiums | 3 | 1 | 3 | 1 | 3 | 1 | 1 | 1 | 3 | 3 | 3 | 2 | 2 | 2 | 1 |
| #2 | High-Power Chargers Connected to Transmission Line | 3 | 1 | 3 | 2 | 1 | 1 | 2 | 3 | 3 | 3 | 2 | 3 | 2 | 1 | 2 |
| #3 | Depot Charging for Heavy-Duty/Passenger Fleets | 3 | 2 | 2 | 1 | 1 | 1 | 2 | 3 | 3 | 3 | 2 | 2 | 2 | 1 | 2 |
| #4 | Charging Hubs in Commercial Zones | 2 | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 3 | 3 | 2 | 2 | 2 | 1 | 2 |
| #5 | Rural and Seasonal Charging Areas | 3 | 3 | 2 | 1 | 2 | 1 | 1 | 2 | 3 | 2 | 2 | 2 | 2 | 2 | 3 |
| #6 | EV Charging in Dense Urban Neighborhoods | 3 | 2 | 3 | 2 | 2 | 1 | 1 | 1 | 3 | 2 | 2 | 1 | 1 | 2 | 1 |
| #7 | Industrial Light Fleet Charging | 3 | 2 | 3 | 2 | 1 | 1 | 1 | 2 | 3 | 3 | 2 | 1 | 1 | 2 | 2 |
| #8 | Residential EV Charging | 2 | 2 | 2 | 1 | 2 | 2 | 1 | 1 | 3 | 3 | 2 | 2 | 2 | 2 | 1 |
| #9 | Commercial Building EV Charging for Fleet and Employees | 3 | 3 | 3 | 2 | 1 | 1 | 1 | 2 | 3 | 3 | 2 | 2 | 2 | 2 | 1 |
| #10 | Vessel Charging at Ports | 3 | 3 | 3 | 2 | 1 | 1 | 2 | 3 | 3 | 2 | 3 | 3 | 2 | 2 | 2 |

This dual-ranking system for grid constraints and mitigation strategies offers a practical and scalable framework for evaluating the technical and operational challenges posed by EV charging infrastructure. By quantifying both the severity of grid impacts and the intensity of required interventions, this methodology enables planners to make data-driven decisions. It supports the identification of high-risk scenarios, aligns mitigation efforts with actual grid conditions, and ensures that simulation activities in subsequent tasks are focused on the most critical and representative use cases.

## 3.3. Methodologies and tools for grid capacity enhancement

One of the most significant shifts in planning methodology is the move toward probabilistic analysis. Techniques such as Monte Carlo Simulation (MCS), probabilistic load flow (PLF), and state enumeration allow planners to assess the likelihood of constraint violations, quantify risk, and evaluate system reliability under a wide range of conditions.

In parallel, scenario-based planning is being adopted to explore multiple plausible futures. This approach enables utilities and regulators to test the resilience of investment strategies against different trajectories of DER adoption, electrification, policy changes, and climate impacts. Scenarios can be used to stress-test the grid, identify tipping points, and prioritize flexible, no-regret investments that perform well across a range of outcomes.

Another key advancement is the use of multi-objective optimization techniques. These tools allow planners to evaluate trade-offs between goals such as cost, reliability, emissions, and hosting capacity. Evolutionary algorithms are commonly used to generate Pareto-optimal solutions, providing decision-makers with a spectrum of options rather than a single outcome. This is especially useful in distribution planning, where localized constraints and stakeholder preferences must be balanced.

Ultimately, the effectiveness of these planning tools depends not only on their technical sophistication but also on their integration into regulatory and organizational processes. The process must be iterative, transparent, and inclusive, involving coordination between TSOs and DSOs, engagement with stakeholders, and alignment with policy objectives.

To support the transition toward more flexible, data-driven, and decentralized electricity grids, a wide range of grid planning tools have emerged. These tools vary significantly in terms of their technical capabilities, automation levels, forecasting integration, and suitability for different voltage levels. The benchmarking exercise illustrated in Table 20 highlights that while many tools offer strong technical modelling capabilities (e.g., power flow and reliability analysis), fewer provide integrated support for probabilistic planning, economic evaluation, or automated scenario generation. Tools such as Plexigrid and Utiligize stand out for their use of digital twins and AMI-based forecasting, while others like Adaptricity and PlanOS offer robust techno-economic modules. However, many tools still rely on manual processes and lack full integration across planning functions.

**Table 20 – Comparative assessment of planning tools for distribution grid flexibility.**

| Tool | Pros | Cons | Risk and weather | Interface | Automatic | Techno-economic | Forecasts | Probabilistic | Prioritization |
|---|---|---|---|---|---|---|---|---|---|
| Adaion | - Customizable<br>- Powerful | - Low maturity<br>- Steep Learning curve | None | High | Medium | Medium | Low | Low | None |
| Adaptricity | - Strong electrical simulation capabilities | - Classical planning tool<br>- Complex integration | None | Medium | None | Medium | None | Medium | None |
| Advanced Infrastructures | - Interface<br>- GIS integration<br>- Forecasts | - UK centric<br>- Data dependency | None | High | None | None | High | High | None |
| CYME (Eaton) | - Strong technical tool with strategic investment decision module | - Performance bottleneck with large datasets | Medium | Low | Medium | Medium | Low | Low | Medium |
| KOPR | - Advanced simulations and predictive analysis | - Assumes good AMI coverage and information | None | High | Medium | Medium | Medium | Medium | None |
| DPLAN | - Technical accuracy<br>- Multiple modes available | - Low-level programming<br>- Low availability to customize | None | Low | None | Medium | Low | Medium | None |
| Encoord | - Multi-energy and multi-level planning | - Not suited for DSOs | None | High | None | Low | Medium | None | None |
| Envelio | - Scalable for DSOs | - Data quality dependency | None | High | Medium | Low | Medium | Low | None |
| GridScaleX (Siemens) | - Planning tool working with PSS-E and integrated to Copperleaf | - Costly | Low | High | Medium | Medium | None | Medium | High |
| Milsoft | - Detailed GIS-based modelling | - Desktop centric | None | Low | None | Low | Low | None | None |

| Tool | Pros | Cons | Risk and weather | Interface | Automatic | Techno-economic | Forecasts | Probabilistic | Prioritization |
|---|---|---|---|---|---|---|---|---|---|
| PlanOS (GE Vernova) | - Strong technical tool with economic and optimization module | - Enterprise-level focus<br>- Complexity for new users | Low | Low | Low | High | None | High | Medium |
| Plexigrid | - Investment planning optimization<br>- Capacity availability | - Suited for other Plexigrid tools (Flex and LV monitoring) | None | Medium | Low | Medium | Low | Medium | None |
| PSS-E (Siemens) | - Electrical simulation tool | - Only electrical simulations | None | High | None | None | None | None | Low |
| Sensewaves | - Advanced scenario testing<br>- Workflow integration | - Requires AMI | None | Low | Medium | None | None | None | None |
| Synergi | - Strong electrical simulation capabilities and good integration | - Enterprise-level focus<br>- Low automation | None | Low | None | Low | None | Low | None |
| Utiligize | - Powerful simulation capabilities | - Low ecosystem maturity<br>- Requires high grid data quality | None | High | Medium | Medium | High | Medium | Medium |
| Vision | - High focus on LV, earthing and protection | - Desktop centric (limited cloud features) | None | High | None | None | None | Medium | None |
| VisNet Connect | - Instant Connection requests | - No simulation or investment tools | None | High | Medium | Medium | None | None | None |

# 4. CONCLUSIONS AND RECOMMENDATIONS

The integration of DERs, the electrification of end-use sectors, and the increasing penetration of variable renewable energy are driving a fundamental transformation in the way electricity grids are planned, operated, and regulated. This transformation requires a coordinated evolution of technical methodologies, regulatory frameworks, and market structures to ensure that power systems remain reliable, resilient, and economically efficient.

One of the most significant shifts is the move from deterministic to probabilistic planning approaches. Probabilistic planning enables more robust and risk-informed decision-making, particularly in more decentralized and digitalized environments. In parallel, there is a growing need for integrated coordination between TSOs and DSOs. Effective grid performance increasingly depends on seamless data exchange, aligned forecasting, and joint investment strategies across grid levels.

Key strategies include upgrading critical grid components, such as transformers, feeders, and substation, to address immediate capacity constraints. These physical enhancements are increasingly complemented by digital technologies, including SCADA systems, advanced distribution management platforms, and AI-driven analytics, which enable real-time monitoring, predictive maintenance, and optimized asset utilization.

Real-time operational capabilities must also evolve. The deployment of advanced monitoring, control, and automation technologies is essential to maintain system stability under dynamic conditions. These technical advancements must be supported by institutional collaboration among policymakers, regulators, and utilities to refine the technical, regulatory, and economic frameworks that govern decentralized grids.

At the distribution level, the development of structured markets for DERs is critical. These markets must balance efficiency, financial viability, and system reliability while addressing early-stage challenges such as pricing granularity and market access. DSOs are expected to play a central role in facilitating these markets, including through aggregation, dispatch coordination, and settlement services. To support long-term system stability, market designs should also incorporate energy storage and long-term contracts that enhance DER participation and mitigate volatility.

A phased implementation strategy is recommended to align planning and operational practices with long-term system goals. In the initial phase, the focus should be on ensuring physical reliability, safety, and resilience through targeted infrastructure reinforcements and digitalization. The second phase should prioritize the development of market and regulatory structures that enable DERs to provide cost-effective alternatives to traditional grid investments. Finally, the third phase should address organizational design, aligning utility functions and market mechanisms with evolving policy objectives and ensuring transparency and oversight.

Regulatory frameworks must also adapt to the realities of DER growth. This includes designing transition pathways that begin with minimal system enhancements and progress toward advanced capabilities such as DER-enabled system services and investment deferrals. Future-proofing planning processes is essential to account for DER scalability and policy shifts, thereby avoiding stranded investments and ensuring long-term adaptability.

Several analytical principles should guide this transformation. Planning and investment decisions must be aligned with overarching policy objectives, including reliability, safety, affordability, and decarbonization. Market structures should be assessed for their ability to support both centralized and decentralized solutions, recognizing that hybrid models may be necessary. Innovation must be balanced with regulatory readiness, ensuring that emerging technologies such as digital twins, AI-based forecasting, and integrated modelling platforms are effectively integrated into planning frameworks.

Finally, in a more practical approach, the proposed case studies presented in this deliverable serve as base elements for subsequent tasks in this work package, particularly those focused on simulation, validation, and tool development. At the same time, ongoing tasks, especially those related to the design and implementation of flexibility services, will continue to shape and refine the case studies. Ultimately, these insights will inform how grid capacity optimization will be integrated into the AI-based for planning of grids and charging infrastructure being developed within the AHEAD project.

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