Study on network development planning, tariff structures and connection requests for electricity distribution grids

Final report

Written by:

Fraunhofer Institute for Systems and Innovation Research ISI, Project Leader
Fraunhofer Research Institution for Energy Infrastructures and Geotechnologies IEG
Guidehouse
Regional Centre for Energy Policy Research (REKK)

Directorate-General for Energy

2025 EN

Authors:
Anne Kesselring, Fabian Liesenhoff, Michael Haendel, Marian Klobasa, Sabine Anatolitis-Pelka (Fraunhofer Institute for Systems and Innovation Research ISI), Marian Bons, Sjoerd Pernot (Guidehouse), Judith Stute, Stella Oberle, Elena Timofeeva (Fraunhofer Research Institution for Energy Infrastructures and Geotechnologies IEG), László Szabó, András Vékony, Katalin Varga (Regional Centre for Energy Policy Research group REKK)

With support from staff in the respective institutions supplying expertise on the individual member states.

Contact:
Fraunhofer ISI: anne.kesselring@isi.fraunhofer.de
Fraunhofer IEG: judith.stute@ieg.fraunhofer.de
Guidehouse: marian.bons@guidehouse.com
REKK: andras.vekony@rekk.hu; katalin.varga@rekk.hu

August – 2025

EUROPEAN COMMISSION

Directorate-General for Energy
Directorate C — Green Transition and Energy System Integration
Unit C.4 — Infrastructure and Regional Cooperation

Contact: Zuzana Sadlova

E-mail: *zuzana.sadlova@ec.europa.eu*

European Commission
B-1049 Brussels

Study on network development planning, tariff structures and connection requests for electricity distribution grids

Abstract: Distribution grids are critical for the energy transition: with the majority of future assets to be connected at the distribution-grid level, the decentralization and decarbonization of the energy system depend on strong and future-ready electricity distribution networks. This study gathers and analyses data from all 27 member states of the European Union through desk research and interviews, covering three topic areas. First, appropriate network planning as the primary strategic process to prepare distribution networks for the energy system of the future. Second, network tariff design and regulatory regimes, which shape the incentive structures and mechanisms by which grid costs are recovered and grids can be used efficiently. Third, the timely and transparent treatment of grid connection requests, where the strong increase in the volume of requests is leading to backlogs, but also spurring new policy tools to manage grid capacity. The study characterizes the status quo, identifies best practices, and delineates recommendations for the way forward in the European Union.

Directorate-General for Energy

2025 EN

Europe Direct is a service to help you find answers
to your questions about the European Union.

Freephone number (*)**:**

00 800 6 7 8 9 10 11

(*) The information given is free, as are most calls (though some operators, phone boxes or hotels may charge you).

Manuscript completed in June 2025

Revised/Corrected/2rd edition: August 1, 2025

Luxembourg: Publications Office of the European Union, 2025

PDF Web ISBN 978-92-68-31938-3 doi: 10.2833/9351025 MJ-01-25-121-EN-N

CONTENT

ABBREVIATIONS

(*) INDICATES THAT TERM IS ALSO EXPLAINED FURTHER IN GLOSSARY ON THE FOLLOWING PAGE)

A	Ampère
ACER	European Union Agency for the Cooperation of Energy Regulators
AT	Austria
BE	Belgium
BG	Bulgaria
CAPEX *	Capital expenditures
CAPM	Capital asset pricing model
CEE	Central and Eastern Europe
CRU	Commission for Regulation of Utilities (Irish NRA)
CY	Cyprus
CZ	Czechia
DE	Germany
DEA	Data envelopment analysis
DER	Distributed energy resources
DK	Denmark
DNDP	Distribution Network Development Plan
DLR	Dynamic line rating
DSO	Distribution system operator
EE	Estonia
E-Based	Energy-based
ES	Spain
EU	European Union
EUL	Economic Useful Life
EV	Electric Vehicle, also: BEV, Battery Electric Vehicle
FCA*	Flexible connection agreement
FCFS	First come, first served

FI	Finland
FR	France
GAP	EU Action Plan for Grids
GIS	Geographic information system, abbreviation refers to GIS data, i.e. data in a specialized geospatial file format
GR	Greece
GW	Gigawatts
GWh	Gigawatt-hours
HAC	Heating, Ventilation, and Air Conditioning System
HR	Croatia
HU	Hungary
HV	High voltage
ICT	Information and Communication Technology
IE	Ireland
IT	Italy
KPI	Key Performance Indicator
kW	Kilowatts
kWh	Kilowatt-hours
kVA	Kilovolt-ampere
L	Lump-sum
LCT	Low Carbon Technology
LT	Lithuania
LU	Luxembourg
LV	Latvia Note: LV is often also used as “low voltage” in grid studies, this is spelled out to avoid confusion.
MOLS	Modified Ordinary Least Squares
MS	Member State
MT	Malta

MV	Medium voltage
MW	Megawatts
N/A	Not available / no answer
NDP	Network Development Plan (see DNDP for plans specific to distribution level)
NECP	National Energy and Climate Plan
NL	Netherlands
NRA	National Regulatory Authority
OPEX *	Operational expenditures
PAYG	Pay-as-you-go
P-based	Power-based
PHES	Pumped hydro energy storage
PL	Poland
PT	Portugal
PV	Photovoltaic
R&D	Research and Development
RAB *	Regulatory Asset Base
RE	Renewable energy
RED	Renewable Energy Directive
RES / RES-E	Renewable energy sources / Renewable energy sources in the electricity sector
RO	Romania
ROI	Return on Investment
RoR	Rate of Return
RP	Regulatory period
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SE	Sweden
SFA	Stochastic Frontier Analysis
SI	Slovenia

SK	Slovakia
TEN-E	Trans-European Networks for Energy
TOTEX	Total Expenditures
ToU *	Time-of-Use (Tariff)
TSO	Transmission System Operator
TYDNP	10-Year Network Development Plan
V	Voltage, in particular: low V to refer to low voltage, in order to avoid confusion with Latvia (LV)
WACC *	Weighted average cost of capital

GLOSSARY OF TECHNICAL TERMS

Alternative or conditional grid connections	Alternative grid connections, also known as conditional grid connections, are broadly defined as any arrangements that deviate from the usual approach giving the grid user the right to use 100% of contracted capacity at all times (CEER, 2023).[1] This is an umbrella term for measures intended to accommodate new grid users despite capacity constraints, either as an interim solution until grid expansion or as a permanent strategy viewed as a flexibility mechanism. More specifically, the Electricity Market Directive emphasizes the contractual arrangements and defines *flexible connection agreements* as "(…) a set of agreed conditions for connecting electrical capacity to the grid that includes conditions to limit and control the electricity injection to and withdrawal from the transmission network or distribution network."[2]
Anticipatory investments	"Investments into grid infrastructure assets that proactively address network development needs beyond the ones corresponding to reinforcements relating to currently existing grid connection requests by generation or demand projects […] based on identified medium- and long-term network needs, justified in network development plans, based on scenarios that project plausible trajectories of generation and demand capacities that support energy, climate and industrial policies, including the National Energy and Climate Plans"[3]
Benchmarking	Benchmarking in the context of network regulation refers to methods for efficiency benchmarking, i.e. the method by which NRA establishes efficiency scores or reference values against which cost-efficiency of individual network operators is evaluated. Insufficiencies relative to the benchmark must then be resolved within a specified period.
Cable Pooling	Cable pooling is a technology solution, whereby multiple generation assets share a single grid connection. This can be a technology used to implement flexible connection agreement. Related terms are shared connections, hybridisation meaning the combination of different asset types

[1] See: CEER (2023). Alternative connection agreements [working paper]. https://www.ceer.eu/wp-content/uploads/2024/04/ACA_2023.pdf

[2] Article 2 of Directive 2024/1711 amending Directives (EU) 2018/2001 and (EU) 2019/944 as regards improving the Union's electricity market design. Link: L_202401711EN.000101.fmx.xml

[3] European Commission (2025). Commission notice on a guidance on anticipatory investments for developing forward-looking electricity networks. guidance on anticipatory investments for developing forward-looking electricity networks.pdf

	for higher utilization, or even overbuilding of connections going above nominal capacity.
Capacity Maps and comparable information tools	Digital tools with a spatial representation providing information about the available grid capacity. Most common are map representations, but there are other "comparable information tools" that fulfil the same purpose, for example live search tools by zip code.[4]
CAPEX	Capital expenditures comprise the upfront costs to build and expand the grid, i.e. land, assets of physical infrastructure and capital costs (see WACC). Figures for CAPEX in the grid context are typically reported in terms of annual amortization.
Conditional grid connections	See above: Alternative grid connections.
Cost recovery models for distribution tariffs	Cost recovery models refer to the principal approaches by which system operators can recover their investment costs, i.e. the approach taken to allocate network costs across users via tariffs. The average cost model recovers costs based on the historical or current average costs of the network. The forward-looking cost model is based on the expected or projected costs of the network, including planned investments. The incremental cost model focuses on the additional or marginal costs that arise from serving new demand or adding new users to the system. The basic models further differ by which investment types can be recovered, how the cost items are accounted for, and how tariff design contributes to cost recovery.
Deep vs. shallow connection charges	Deep and shallow are the main design options for connection charges. Shallow charges are based on the direct costs for establishing the immediate physical connection to the grid. Deep charges also include the indirect cost of reinforcing or upgrading the broader grid to accommodate the new connection, i.e. upstream grid investments.
Dynamic line rating	Dynamic line rating (DLR) is a technology that recalculates the thermal capacity of power lines using external conditions (e.g. wind, temperature). In contrast to static line rating, which is based on a conservative worst-case, this allows higher utilization of the grid.
Flexible connection agreements	See: alternative grid connections above.
Forecasting	Forecasting, or more specifically load forecasting, refers to the process and methodologies used to predict electrical loads. It is the power sector specific version of demand forecasting as a general business activity. In this study, the focus

[4] EU DSO Entity (2023, p. 23 and 24). DSOs Fit for 55 [report] https://eudsoentity.eu/wp-content/uploads/2024/09/DSO_SolarReport_2023-v11.pdf

	is on long-term forecasting as a planning activity, as opposed to short-term forecasting in the operations of the system operator. In this sense, forecasting is related to scenario building in planning future grid needs.
G-charges	Transmission level injection charges that include cost recovery for costs for building, upgrading and maintaining infrastructure (CAPEX & OPEX), but do not include connection charges, charges for ancillary services, or charges for system losses. An upper limit for G-charges is set for each MS within Commission Regulation (EU) 838/2010.
Grid observability	Grid observability refers to "temporal, geospatial, and topological awareness of all grid variables and assets."[5] In the context of distribution grids, this requires further digitalization of the grid especially at the lower grid levels, including smart meters making energy flows visible, but also technology needed to monitor and control variables like temperature, currents, voltage etc., ideally in real-time.
OPEX	Operational expenditures refer to the cost of operating and managing the grid, i.e. maintenance, staff, services, and expenses for management and recurring fees. In the distribution grid context, a prominent example for OPEX-driven costs are expenditures for services related to smart grids and forecasting.
RAB	Regulatory asset base: refers to the value of the assets that a regulated entity, such as a DSO, is allowed to earn a return on through tariffs. It typically includes the value of physical infrastructure like cables, transformers, and substations, and in some cases also intangible assets, depending on the regulatory framework
ToU	Time-of-Use tariffs refers to network charges that vary by time. Static ToU designs have different rates by time-of-day, e.g. lower rates at night. Dynamic ToU can be different each day and set price signals based on current grid conditions. This is one form of variable network charge as a broader set of design options using temporal and spatial variation in price signal to set economic incentives.
WACC	The weighted average cost of capital results from a calculation of interest to be paid on debt capital and expected return on equity, weighted by the respective shares of debt and equity. In the

[5] E.DSO (2022). Grid observability for flexibility [report in Go4Flex project] https://www.edsoforsmartgrids.eu/content/uploads/2024/05/20220513_TF1_ANM_-_Go4Flex_Report.pdf

	context of grid investments, the WACC is set by regulation and updated periodically.

1. EXECUTIVE SUMMARY

CONTEXT AND OBJECTIVES

Decarbonizing the European Union (EU) energy system is a central aim in the EU's energy policy and renewable energy is the key to achieving it. The revised Renewable Energy Directive (RED) has set a binding renewable energy target of 42.5% by 2030, which is a steep increase from the current status of 24.5% and a step up in ambition at the same time.[6] In this context, the EU is pushing the energy transition forward by encouraging the generation of renewable energy and by shifting economic activity towards electrification. This comes with new challenges through rising electricity demand, a larger number of decentralized assets, and the need for storage and flexibility to handle the increased volatility of supply.

Distribution grids are critical to achieve this vision. Estimates indicate around 70% of all assets will be connected at the level of the distribution grid in the future, but current infrastructures are ageing and not yet fit for the challenge ahead.[7] Moving away from a centralized generation model to a multitude of decentral and central assets with bidirectional power flows means not only an increased coordination challenge overall, but specifically a shift in responsibility towards the distribution grid and hence the Distribution Systems Operators (DSOs). The Clean Energy Package in particular recognizes DSOs as a key player in managing the new connections.[8] The Grid Action Plan (GAP) presented in late 2023[9] specifies the policy agenda and pinpoints 14 critical areas for urgent action: distribution grids are the target for 8 of those 14 actions, and in fact, most items in the GAP have at least indirect implications for distribution grids and their operation. Despite this key role of distribution grids in the energy transition, data availability and therefore the understanding of current practices and challenges lag behind in light of the strong need for action.

This report thus presents the results from a comprehensive study to provide insights on the state of distribution networks in Europe along three topic areas:

1) Network development planning,

2) Network tariff regimes and regulatory incentives, and

3) Timely and transparent treatment of grid connection requests

The purpose of the study is to gather the data needed for an overview of best practices, challenges and relevant considerations regarding distribution network development and utilisation across Europe. Building on this overview, an in-depth assessment of selected practices is conducted, which identifies ways forward towards the ambition of the context outlined above. The report subsequently provides recommendations, both regarding action at the EU level and regarding insights from EU Member States (MS) with relevance to EU-wide practices.

The methodology combines secondary data analysis and primary data collection with the geographical scope encompassing the 27 MS. The knowledge base for the study was collected in a first stage from public sources (i.e., through desk research), and complemented in the second stage with an interview study. The collected data thus identifies the status quo in all 27 MS at a descriptive

---

[6] European Environment Energy (2025). Share of energy consumption from renewables. https://www.eea.europa.eu/en/analysis/indicators/share-of-energy-consumption-from.

[7] Eurelectric (2023). Grids for speed [report]. https://powersummit2024.eurelectric.org/grids-for-speed/

[8] Centre on Regulation in Europe (2021). Optimal regulation for European DSOs to 2025 and beyond. https://cerre.eu/publications/optimal-regulation-european-dsos-energy-transition/

[9] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2023%3A757%3AFIN

and aggregate level. From this data, the study presents both a comparative analysis *across* the MS and further insights on selected practices *within* MS. Recommendations for each topic area are developed accordingly. The report is accompanied by 27 factsheets and summary tables capturing the status quo across Europe, which are presented in the appendix of the report.

MAIN FINDINGS

Appropriate Network Development Planning

Regulatory regimes and practices for the design and implementation of DNDPs

There is substantial **heterogeneity in the practices regarding distribution network development plans (DNDPs)** across MS. DNDPs vary widely in terms of terminology, scope, and transparency (e.g. from simple investment lists to detailed development plans). The **harmonization of DNDPs within MS** is relatively low and aggregation at national level is not common practice, although most MS with more than one main DSO (15 out of 27) provide at least some guidance for DSOs within a country. The study identifies two pathways for harmonization: (i) legal prescriptions (e.g. FI, NL) and (ii) NRA-issued templates (e.g. AT, DK, PL). The study notes that current practices do not consistently conform to EU requirements, pointing out to the different level of implementation of Electricity Directive provisions on network planning[10] across Member States. The study proposes elements that should be part of **advanced DNDPs** (stemming from requirements of EU legislation but also going beyond it). This includes for example the explicit use of flexibility (e.g. AT), long-term risk analysis (e.g. PT), or aligned scenarios on a national level (e.g. NL).

Procedural steps, data collection and governance of DNDPs

The **procedural structures** for DNDPs differ significantly across MS in terms of geographical coverage, timelines, and scope, but importantly also in the alignment with TSO planning cycles. Regarding **governance**, NRAs typically oversee DNDP approval, but other stakeholders are involved (e.g. competition authority, Ministry, transmission system operator (TSO)). **Public consultation** is applied inconsistently. There are strong examples involving customers and municipalities (e.g. FI, HR, IT). However, public consultation procedures remain short and limited in many MS. 5 MS do not conduct full public consultations currently. The extent of **TSO-DSO exchange and alignment** varies as well, with best practices include shared analytical frameworks (e.g. SE, FR), shared scenario definitions (e.g. NL) and emerging use of smart meter data for planning (e.g. SI, SE, EE).

Integration of renewables, development of charging stations and electrification of heating and cooling of buildings

MS apply diverse **scenario modelling** approaches, typically combining elements from multiple scenario types, though the number, scope, and methodology are often not detailed in DNDPs. There is no single best practice: streamlined unified approaches (e.g. FR, FI) serve the purpose as well as mixed-method approaches (e.g. AT). Three levels of **flexibility integration** are observed in the study: (1) grid-enhancing technology additions (e.g. dynamic line rating), (2) market development of flexibility (e.g. integration of commercial storage in electricity markets), and (3) active flexibility use for grid relief – though the latter is rare to date. **Grid reinforcement** remains the dominant strategy in DNDPs, while more advanced solutions like grid enhancing technologies and flexibility use are still in pilot phases and not widely scaled across MS.

Deep dives: selected practices for network development planning

The study identifies harmonization, actionability and flexibility integration as critical for Distribution Network development planning. In this context, the following selected practices are explored:

[10] Article 32 of the Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast), setting up basic requirements for DNDPs.

Table 1: Selected practices for network development planning

Harmonization	Actionability	Flexibility integration
• **Hungary**: Integrated TSO-DSO network development plan with continuous alignment and data exchange • **Germany**: Harmonization through regional planning zones, coordinated by law	• **Netherlands**: Addressing grid congestion with new contract types, cable pooling and flexibility markets • **Germany**: Detailed grid maps and explicit legislative requirements for DNDP actionability • **France**: strong collaboration between national and regional actors through dedicated programme	• **Denmark:** Forecasts on flexibility present in DNDP that assess availability and effective use • **Finland:** Legislation obliges DSOs to develop a plan for using flexibility in the DNDPs

Network tariff regimes and regulatory incentives

Network tariff regimes

For **withdrawal charges**, most MS use a combined approach with energy-based and power-based/lump sum components. Design choices typically include variation based on voltage level and/or consumer type (household, business), as well as different exemption rules for small users, sectoral coupling technologies and vulnerable customers. **Variable network charges** are emerging, most commonly as time-of-use tariffs which are applied in over two-thirds of MS for withdrawal. They are seen as the best option to improve efficient grid use and operation. The design of such charges varies by time of day, weekday, season, and sometimes by consumer type. 19 MS apply variation by time-of-day, while others use less granular designs or combine seasonal and intra-day variation. Implementation hinges on the availability of smart metering and grid digitalization. **Injection charges** are increasingly applied: over one-third of MS apply them for reasons of cost-reflectivity, albeit with some countries applying negative charges to incentivize production. The use of injection charges can positively contribute to cost reflectivity but can distort location choices for generation units with negative economic consequences. Cross-border effects can be negative as well depending on the pass through of price changes to end customers. Due to these caveats to injection charges they are considered a second-best option to relative to the aforementioned locational price signals that reflect grid conditions. Especially in regions with large amounts of generation, which requires substantial grid expansion, cost reflectivity can be improved and costs currently covered only by consumers can be reduced. For this reason, injection charges should be considered as one option when network tariff regimes are adapted.

With regard to network tariff regimes, there is currently wide variation in the treatment of **storage facilities**, which is characterized by differences in the application of withdrawal and injection charges (if any), as well as exemptions. **Cost recovery** at distribution level is most commonly based on average cost allocation. Best practices emerge regarding forward-looking (e.g. HR, EE, SE) and incremental cost models (e.g. FR, PT). Currently, cost recovery heavily relies on withdrawal charges, while injection charges play only a minor role in cost recovery – with the notable exemption of SE.

Regulatory incentives

With respect to **regulatory regimes**, most MS apply incentive regulations characterized by a revenue cap (14 MS), or less commonly price caps (4 MS). Cost regulations are less common, although some MS combine cost regulation with components of incentive regulation (e.g., BE, DK, IT). The **regulatory asset base** (RAB) is typically used as a key component for determining allowed revenue. While fixed assets are commonly included in the RAB, working capital and assets under construction, as well as intangible assets are often excluded or limited. The **regulatory approval**

of cost recovery is handled very differently across MS. In particular, there is variation in possible adjustments for capital and operational expenditures. **Anticipatory investments** are an emerging topic, but there is no consistent application for this across the EU to date, as definitions have only recently emerged. Overall, current regulatory regimes tend to constrain the solution space for DSOs, for example by not incentivizing smart grid investments.

Deep dives: selected practices for network tariff regimes and regulatory incentives

Based on the status quo, the study identifies different means for innovative and cost-reflective network tariffs, and emphasizes the need for regulatory regimes to allow and incentivize DSOs to act more forward-looking in their investment strategies. Against this background, the following selected practices are explored:

Table 2: Selected practices for network tariffs and regulatory regimes

Tariff regimes & exemptions	Anticipatory investments	Incentives for smart grid investments
▪ **Slovenia and Spain**: Combination of energy- and power-based time-of-use withdrawal charges ▪ **Denmark and Sweden**: Cost recovery through injection charges with variable component ▪ **France, Croatia, Sweden**: incremental and forward-looking cost allocation models	▪ **Denmark:** Possibility to include "green investments" into the regulatory asset base (RAB) ▪ **Hungary:** Investment in higher capacities based on anticipated higher demand	▪ **Denmark and Ireland:** different performance-based incentives, including incentives for smart metering

In addition, the study looks at new practices from Ireland and Denmark regarding possible ways to allow more flexibility with adjustments *during* the regulatory period, which allows to close the time gap between incurring expenses and their recognition in revenue regulation, thus lifting possible disincentives.

Timely and transparent treatment for grid connection requests

Determination of grid connection potential

MS use varying assumptions and definitions for calculating grid capacity. **Legal obligations** for "timely" grid connection exist in most MS but it is not transparent to what extent these are kept or enforced. In addition, there are unclear roles, especially regarding NRA involvement. DSOs play the main operational role, while **responsibilities** are fragmented. Most MS use **capacity maps or similar tools** (e.g. PT uses a postal code search). However, tool design and detail vary widely, for example regarding granularity, voltage level coverage and updating frequency. Best practices include interactivity (DK, DE), searchability (BG), downloadability (IE), and open data principles (CZ). From the **user perspective**, some MS provide centralized access platforms (e.g. EE, LT), while others rely on decentralized DSO-specific systems.

Measures in case of lacking capacity

With increasing electrification and decentralization, **grid congestion** is starting to emerge as a threat, although many MS are not yet experiencing widespread grid congestion as a national-scale problem. Measures vary widely depending on local grid congestion levels and national priorities. While basic **legal principles** (e.g. non-discrimination) are common, detailed procedures lack transparency. Almost all MS use first-come-first serve principles. However, at least 15 MS have experienced queuing problems, leading to priority schemes being tested. In those cases, **priority** is often given based on asset type, project characteristics or social importance, or (e.g. small-scale, congestion relief). Overall, **incentives mechanisms** for speedy connection between policy-makers, DSOs, and users are not aligned and fragmented across MS. In situations where grid queues emerge, legal and administrative capacity often lags behind technical needs, especially in fast-growing demand areas. **Flexible connection agreements** are being rolled out (e.g. AT, SE, NL), but typically applied only as a temporary solution with limited scope. Regulatory measures to empower DSOs active management of demand-side flexibility are explored as an alternative to user-oriented measures in some MS (e.g. DE) to unlock grid capacity without immediate infrastructure upgrades.

Process for grid connection requests

Connection **lead times** vary significantly, ranging from a few days (e.g. IT, EE) to over a year (e.g. CY, DK). The timing depends on grid level, project size, local constraints, and whether permits or authority coordination is required. **Deadlines** are mostly legally defined (e.g. in energy laws or network codes) or stated as "timely", thus leaving discretion to DSOs. Backlogs are often related to an increasing number of requests while grid congestion is a major constraint limiting approval. These issues with grid congestion are a major issue occurring in an increasing number of member states (e.g. NL, HU), but other factors also contribute to backlogs. This includes in particular speculative requests (e.g. IE, SK), and administrative/organizational constraints (e.g. DE, PL). Given these diverse drivers for backlogs, there is no one-size-fits-all solution but rather a toolbox of policy options to be employed. Regarding **digitalization**, almost all MS have basic digital solutions, but only 11 MS have fully digitalized processes through solutions like fully interactive platforms (e.g. PT). Grid connection processes are coming under scrutiny in many MS currently, triggering **reforms and streamlining efforts**, the empirical effects of which will only show over the next years.

Deep dives: selected practices for timely and transparent treatment of grid connection requests

The study shows that the current handling of grid connection requests across the EU is highly heterogeneous and that emerging issues with grid capacity are likely to become more widespread as the volume of grid connection requests are distribution level increases. Nevertheless, there is an emerging solution space from different measures. In order to better categorise the opportunities and challenges involved in applying for a grid connection in a timely and transparent manner, the study took a closer look at the following selected deep dives:

Table 3: Selected practices for treatment of grid connection requests

Grid connection potential	Measures in case of lacking capacity	Transparent processes
▪ **Estonia:** connection capacity potential app based on nationwide monitoring system ▪ **Germany:** Tool of an individual DSO for checking grid connection request with extended planning functions for potential project developers	▪ **Croatia**: Investor agrees to connection before creation of technical conditions ▪ **Netherlands:** First come first serve with predetermined priority framework ▪ **Hungary:** Pro-rata vs Tender-based procedure to better manage capacity ▪ **Poland:** Planned auction of available capacity	▪ **Estonia:** One-stop-shop making use of high degree of digitalization ▪ **France:** Online platform with different procedures depending on costumer group

Recommendations

Recommendations are derived for each of the topic areas. **Table 4** below presents these recommendations and links each of them to the respective level, at which action needs to be taken: the EU at supranational level, the MS in their regulatory frameworks and national processes, or the DSO level, which is here used to indicate action in practices at the level of the individual grid area.

Table 4: Recommendations derived for each subtopic and actors/institutional levels at which action is needed

Recommendation	Action Level (EU, MS, DSO; TSO)
1. Topic area: Appropriate Network Development Planning	
Subtopic 1: Regulatory regimes and practices for the design and implementation of DNDPs	
Improve transparency and accessibility of DNDPs by enforcing full public publication and encouraging English summaries.	MS
Harmonise DNDPs between DSOs within each Member State by developing a common reporting structure.	MS; DSO
Increase the actionability of DNDPs by enforcing inclusion of detailed investment plans and requesting the development of capacity maps, considering results of the DNDP in terms of network development.	MS; DSO
Subtopic 2: Procedural steps, data collection and governance of DNDPs	
Ensure public consultation is conducted by enforcing legislation, recommending a suitable minimum duration, and facilitating engagement.	MS
Ensure results of the public consultation are submitted to the NRA and published publicly by obligating it in legislation and enforcing it.	MS
Strengthen coordination between DSOs and TSOs in scenario development and network planning, including on timelines.	MS; DSO; TSO
Subtopic 3: Integration of renewables, development of charging stations and electrification of heating and cooling of buildings	
Promote the alignment of scenarios and establishment of working groups on scenario development, including DSOs and TSO(s).	DSO; TSO
Consider grid enhancing technologies (e.g. dynamic line rating) as measure to be deployed instead of / next to grid development and report on their usage in DNDP.	DSO
Encourage inclusion of flexibility forecasting and flexibility use as measure in DNDPs by requiring assessment and reporting of flexibility needs and potential.	MS
2. Topic area: Appropriate Tariff Regimes and Regulatory Incentives	
Subtopic 1: Network tariff regimes	
Variable network charges should be introduced to improve the efficiency of grid use, but the design options must consider trade-offs with transparency and non-distortion.	MS; DSO
Dynamic structures in tariff regimes should be introduced step by step, and consider the cost-benefit trade-off from needing more measurement technology.	MS; DSO
Locational price signals should be focused on maximizing grid utilization for better system efficiency, which includes both generation and consumption.	MS; DSO
Injection charges should be evaluated in all MS against the principle of cost reflectivity, such that the generation side contributes adequately to the system costs.	MS
The design of injection charges should be based on quantitative studies to assess the mechanisms by which their introduction affects both grid and market factors.	MS

Subtopic 2: Regulatory incentives for DSOs	
Anticipatory investments: the EU policy discourse should adopt and promote definition by the European Commission guidance to sharpen clarity and allow comparison across MS.	EU
Anticipatory investments should not be considered a cost category of their own, but rather reflected in different cost categories.	MS
The EU should support the development of a methodology for the cost-benefit analysis regarding the higher uncertainty of anticipatory investments.	EU
Regulatory framework should ensure that there is no time gap between incurring expenses and their recognition for revenue regulation.	MS
NRAs should take into account the use of performance-based incentives for smart grid solutions, incl. smart meters, within regulatory frameworks	MS
3. Topic area: Timely and transparent treatment for grid connection requests	
Subtopic 1: Determination of grid connection potential	
Methodologies applied to assess capacity should be made more transparent and harmonized across DSOs within Member States.	MS, DSO
Harmonization of tools at EU-level can be advanced by focusing on requirements, rather than on the specifics of implementation.	EU
The introduction of an EU-wide transparency platform should be pursued with a focus on interface design and stakeholder heterogeneity.	EU
Subtopic 2: Measures in case of lacking capacity	
More clarity should be provided regarding the use cases for flexible connection agreements in current policy and in practical experience.	EU
Flexible connection agreements could be supported with a model-based study laying out the key parameters for policy design.	EU
Subtopic 3: Process for grid connection requests	
Increasing lead times from a backlog of pending grid connection requests have to be tackled with a portfolio of tools specific to the root problems.	MS; DSO
Best practices and experiences from other sectors dealing with fragmentation could support user-friendly system development.	DSO

Besides these recommendations by topic area, three cross-cutting themes are identified:

- Grid observability is a pre-requisite for the implementation and combination of many best practices and advanced solutions.
- Incentive structures underpin the development of distribution networks: this encompasses both incentives for DSOs to adopt new approaches, but also for grid users to use network capacity effectively and efficiently.
- Anticipation is a recurring theme that is slowly being addressed in distribution networks as a principle, not only in regulatory frameworks for investments, but also in planning.

The recommendations reflect the criticality of distribution grids in the energy transition that is evident throughout the study's findings. To advance distribution networks across the European Union, action is required at all institutional levels: from the supranational level of the EU, through MS national frameworks, and by DSOs working directly with the grids and users. This study contributes by improving the knowledge base and helping to identify the way forward.

2. OBJECTIVES AND METHODOLOGY OF THE REPORT

Context. The decarbonisation of the European Union (EU) energy system requires a distribution network development that aligns with the rapid adoption of renewable energy and sectoral coupling technologies.

The transformation is happening simultaneously in generation and in consumption. On the **generation side**, renewable energy sources are expanding rapidly: Just in the period of 2022-2024, a record of 168GW of solar and 44 GW of wind capacities were installed in the EU.[11] This means that by 2024, 47 % of electricity generation in the EU came from renewables – with a continued upward trend expected. On the **consumption side**, electrification is progressing along several dimensions: electric vehicles are transforming mobility, heat pumps are gaining traction, industrial processes are being re-powered with clean electricity. This means more grid users, higher loads, and more complex supply-demand patterns.[12] Distribution grids are critical to accommodate these changes: the majority of new assets in a decentralized energy system will be connected at the distribution level.

However, distribution grids are also at risk of becoming a bottleneck of the energy transition due to several factors. **Infrastructure** is ageing: more than 40% of EU distribution grids are over 40 years old[13], meaning investment is needed already to maintain the system, let along make it future-ready. **Technology** is needed: grid observability is technically feasible, but investments in digitalization are not on track in many places and DSOs are facing obstacles to transform their operations. **Processes** are changing: grid connection requests are soaring as the energy system is becoming decentralized, leading to connection queues emerging in several countries already. In brief, the planning, financing, and administration of distribution grids needs to adjust to meet the needs of a decarbonized, decentralized energy system.

While the challenge for the EU distribution system is massive, **recent policy initiatives** have identified the major pain points and are working on measures to address them at the EU level. Most prominently, the Grid Action Plan lays out 14 concrete actions targeting financing, network planning, use of efficient technologies, support for infrastructure development, supply chains, treatment of connection requests but also grid hosting capacities. These actions are embedded in a wider policy agenda. For example, smart grid initiatives are being taken up under the Projects of Common Interest. Household concerns are being addressed through the Affordable Energy Action plan, while industry is being addressed through several plans, including key sectors such as automotives and steel.[14]

While the first steps have been taken, the pathway continues to evolve. Monitoring the status quo and future needs of the network and setting appropriate incentives for the distribution system operators (DSOs) and for grid users connecting clean technologies to the network are key activities on this pathway. There is a need to further develop the legal frameworks and incentive structures that support and steer distribution grid development. However, limited experiences with this rapid transition, varying decarbonisation trajectories and structural differences of the national distribution grids have led to different measures and activities on the national level in the status quo.

Objectives. This report presents the results from a comprehensive study to provide insights on selected practices and key design features among the EU-27 Member States (MS). The aim is twofold: to improve the understanding of current practices and challenges, and to deduct recommendations on how to advance distribution grids towards the critical role they have in the energy transition.

---

[11] European Commission (2025). C_202503179EN.000101.fmx.xml

[12] Eurelectric (2024). https://www.eurelectric.org/in-detail/distributiongridsforspeed/; European Commission (2025). https://energy.ec.europa.eu/news/eu-guidance-ensuring-electricity-grids-are-fit-future-2025-06-02_en

[13] Eurelectric (2023). https://www.eurelectric.org/in-detail/industrialcompetitiveness/

[14] See the Action plans for the respective sectors: https://ec.europa.eu/commission/presscorner/detail/en/speech_25_692 ; 7807ca8b-10ce-4ee2-9c11-357afe163190_en

The report thus provides insights and recommendations based current practices and experiences across Europe in three topic areas:

1) Network development planning,

2) Network tariff regimes and regulatory incentives, and

3) Timely and transparent treatment of grid connection requests.

Terminology. The study captures the similarities to collect the data in a structured manner and to create comparable insights across the MS. In particular, each topic area is decomposed into two to three **subtopics** which are further decomposed into three to five **design categories**. For instance, when examining the second topic area, the distinction is made between two subtopics namely the network tariff as incentives set for the grid users and the distribution grid regulation as incentives set for the DSOs. The different kinds of network charges and exemptions for certain grid users then define the **design categories** under the subtopic of network tariffs. The different options of how to implement a design category are called **design features**. For instance, time-of-use tariffs are one design feature in the design category variable charges.

Regarding the intended outcomes of this second research stage, the structure comparing MS and design features ultimately aims to develop the understanding of each topic from the examination of three kinds of insights that are sought after when comparing the status quo in the MS:

- **Selected practices**: On the one hand, this refers to insights from MS with innovative, supporting regulation and/or network development progress aligned to the adoption of clean technologies and the overarching objectives of energy and climate policy. On the other hand, this refers to the identification of aspects that are pivotal for the transition of the distribution grid to fulfil its new role in the energy system in line with the ambition outlined in the Fit for 55, REPower EU or Grid Action Plan. These practices might not have to be innovative, but simply show different design options applied across the EU 27.

- **Needs for adjustment**: MS with outdated, disincentivising regulation and/or network development progress that is not compatible with the adoption of clean technologies. Adjustments in this sense are not only technological or procedural choices, but also questions of transparency, i.e. aspects that are not well defined or constitute knowledge gaps for the transition of the distribution grids across Europe and the coordination at the European level.

- **Structural similarities and dissimilarities between MS**: MS that have similar drivers, challenges and conditions for the transition of the distribution grid – Best practices and pitfalls may be more transferable for MS with underlying structural similarities. On the flip side, MS are heterogeneous regarding their grid conditions, policy frameworks, and progress on digitalization (e.g., smart meter rollout). This heterogeneity is captured as well, because it may present opportunities for other MS or present constraints to effective EU Action.

Methodology. The following section summarizes the methodology for the collection of the knowledge base in three steps: (1) the desk research establishing the MS factsheets, (2) the interview study completing the data collection, and (3) the selection of deep dives from the full list of identified design features. For the sake of readability, all methodological steps completed are simply described in present tense. The methodology as described below proceeds in parallel for all three topic areas. Details on the methodology are elaborated in the Appendix.

In a first step, the desk research consists of an initial, overarching collection of secondary data from multi-country studies and an MS-specific collection by MS experts. The process also includes monitoring recent policy documents. From this, a common template for the data collection and the items to be collected is developed. This template is then filled through focused literature review per MS. In the second step, the subsequent interview study addresses the open points from the desk research. The interviews are semi-structured, as their primary purpose is to fill knowledge gaps along the design features and categories in light of the information already gathered from desk research. The study aims to maintain geographical balance, noting that there is strong heterogeneity across

MS that is also shaped by grid conditions and economic situations across MS so that selected practices are needed but not unconditionally transferrable.

To structure the progress in this phase from the descriptive nature of the input data to the delivery of an in-depth assessment, we then conduct a synthesis of the data collection through an internal alignment workshop. We identify **priority themes** for each topic that warrant further attention. Priority themes can be cross-cutting to design categories when similar issues run through a topic in multiple aspects. We then select **topic-MS combinations for further deep dive** examination. An example for such a combination of topic-by-MS could be: Flexibility integration (topic) in Austria (MS). These practices (deep dives) are analysed in more detail.

The deep dives follow a common structure, although scope and focus points vary based on the particularities of the topic area.

- **Context** for the practice briefly introducing the background
- **Body of content** explaining the selected practice or method,
- **Evaluation** of the practice in the context of the EU-27.

In the last phase of the study, recommendations are developed. These recommendations serve two purposes. Regarding action at the European level, they aim to identify where and how the EU can support the development of distribution grids along the three topic areas. Regarding the findings that emerge from the deep dives in particular, the recommendations address stakeholders also at the national level. The selected practices give insights on how MS face, address and solve challenges arising through the energy transition in distribution grids across the EU-27.

Structure. The report is organized along the three topic areas. **Chapter 3** presents the results on network development planning. **Chapter 4** presents the results on network tariff regimes and regulatory incentives. **Chapter 5** presents the results on timely and transparent treatment of grid connection requests. Within each of these three chapters, the presentation of results has the same structure:

- The first section presents the design categories chosen for the topic area and explains the relevant terminology.
- The second section contains the comparative findings for each topic, with insights on selected practices and particularities.
- The third section contains the deep dives for each topic area.

Chapter 6 provides the recommendations drawn from the study, again following the three topic areas as structural elements, before **Chapter 7** concludes. The **Appendix** contains further information on the data collected. There are three sections to the Appendix:

- Appendix 1 contains 27 MS fact sheets with condensed, short-form information on the data base which feeds the study.
- Appendix 2 contains summary tables with key design features to provide a direct comparison on selected information items across all MS in a single table.
- Appendix 3 provides additional information on the methods, the interview process and stakeholders consulted for this study.

3. DESIGN FEATURES FOR APPROPRIATE NETWORK DEVELOPMENT PLANNING (NDP)

The strategic aspect of network development planning is the primary procedure for taking action to prepare distribution networks for the energy system of the future. Thereby, network development planning serves to (a) address existing and future grid needs, (b) provide transparency on network development, (c) integrate flexibility services and services complementary to physical grid development, and (d) determine investment in distribution infrastructure (including not only capacity, but also service quality and resilience, as well as smart solutions). These factors are closely interlinked with the needs of grid users, which are covered in Topic 3 under timely and transparent grid connections. Specifically for planning, the above approach to planning is more comprehensive than was previously typical for distribution grids since the development plans for the distribution networks (DNDPs)[15] must now be brought in line with the energy transition objectives, and the construction of scenarios is influenced by the uncertainty that comes with transition periods. The legal basis for this has already been laid out, in particular through Article 32 of the Electricity Directive (see **Infobox 1** below).

In this context, the target for the topic area of network development planning is to identify key design features for appropriate network development planning that are aligned with the national energy and climate plans (NECPs) and the EU wider objectives on renewable expansion and integration of electrification solutions. For the data collection within the EU-27, we explore the topic area along the aforementioned three subtopics, namely:

1. Regulatory regimes and practices for the design and implementation of DNDPs
2. Procedural steps, data collection and governance of DNDPs, including DSO-TSO coordination
3. The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings

To summarize the breakdown of the topic area, **Table 5** summarizes the subtopics and the design categories within the topic area of network development planning.

Table 5: Subtopics and design categories for topic area 1

1. Topic area: Appropriate Network Development Planning	
Subtopic 1: Regulatory regimes and practices for the design and implementation of DNDPs	
Design category 1	Update Frequency of DNDPs
Design category 2	Technicalities of DNDPS (content requirements)
Design category 3	Harmonization within a MS across DSOs
Design category 4	Minimum requirements for DSOs to develop a DNDP
Design category 5	Actionability of DNDP
Subtopic 2: Procedural steps, data collection and governance of DNDPs	
Design category 1	Administrative and Regulatory Procedure
Design category 2	Governance Structure
Design category 3	Stakeholder Engagement
Design category 4	Exchange and Alignment with TSOs
Subtopic 3: Integration of renewables, development of charging stations and electrification of heating and cooling of buildings	
Design category 1	Scenario Building and Forecasting

[15] The abbreviation NDP, network development plan, is established for the national network development plans that are required from the TSOs. The term DNDP refers specifically to planning at distribution grid level.

Design category 2	Flexibility Forecasting
Design category 3	Kind of Measures Proposed as Result of DNDPs, link to investment approval

In summary, the three subtopics reflect three basic research questions: what is being done, how is it currently done, and whether current action looks ahead. While the first subtopic focuses on the general requirements set for the DNDPs (e.g. update frequency, elements to be involved, exemptions for certain DSOs), the second one reports on the process of creating the DNDPs (e.g. which stakeholders to involve for consultation on which basis, who approves the DNDP). The third subtopic focuses on one key element of the DNDPs, namely the forecasting of new grid users. This includes the applied underlying assumptions, if modelling is done or not, to which extent new grid users are considered for flexibility services and which kind of measures are proposed to bridge the gap between the current and future grid infrastructure.

Three institutional levels characterise the design categories of the subtopics. First, requirements set at the EU-level exist for some of the design categories, and the extent of EU action is set to grow further with the implementation of measures outlined in the Grid Action Plan. **Infobox 1** below further elaborates on the EU Policy Actions on DNDPs. Second, national requirements, including regulation and legislation from different governmental bodies, shape the existing framework conditions in each MS. This includes the MS-specific established ways of handling network development at distribution grid level, but also the transposition (or other form of translation) of EU requirements concerning the operationalisation of the DNDPs. Third, the capacity of stakeholders to implement. In some geographies, comprehensive DNDPs at DSO-level were only recently introduced or in the transition period of being introduced. For instance, at this stage a preliminary form (often framed as investment plan, expansion plan or development plan) may be required instead of a comprehensive DNDP that covers all elements as mentioned in introduced legislation.

Infobox 1

BOX 1: EU Policy Action on Distribution Network Development Plans (DNDPs)

Currently, the **Electricity Directive** (Art. 32) sets the framework conditions for network development planning at the distribution level. It mandates at least biennial development of DNDPs by DSOs, and requests information on planned investments and flexibility needs. The plan must be developed in consultation with relevant stakeholders and submitted to the regulatory authority for approval, in order to achieve a transparent and robust network development process.

The proposed **Network Code on Demand Response** (Art. 43 & 44 in version as submitted by ACER on March 7th 2025)[16] is set to further specify DNDP requirements once it comes into force. It aims to ensure and facilitate consideration of flexibility services as complementary to merely grid reinforcements.

The **Grid Action Plan** (in particular Action 3) emphasizes the importance of comprehensive long-term network planning to support higher shares of renewables and increased electrification. It calls for coordination between transmission and distribution network planning, involvement of stakeholders in the DNDP, and adequate data sharing.

[16] ACER. (March 11, 2025) : New network code on demand response will further advance the energy transition. [Annex I]

Lastly, the **anticipatory investment guidance**[17] stresses that network planning is a basis for forward-looking grid investments, which allow integration of electrified load and clean energy sources. It stresses the need for aligned scenarios and sufficiently robust risk assessment framework, linked to DNDPs, to allow for early recognition of needed investment and their execution.

In the following, the design categories for the three subtopics are introduced and contextualised with existing EU requirements and underlying considerations for the design. Subsequently, an analysis of the national requirements and common practices is considered based on the desk research and the conducted interviews among the EU-27 MS. Then, for a selected set of MS – best practice combinations, deep dive descriptions are provided with the aim to identify advanced DNDPs (as laid out in **Infobox 2**) and respective gaps of other plans. For simplification, two-letter codes are used to abbreviate the MS names.

Infobox 2

BOX 2: Definition of Advanced DNDPs

With 'advanced DNDPs' we refer to DNDPs that entail all or at least a substantial amount of information of the requested topics that are mentioned in the Electricity Directive (Art 32) (and in the proposal for a Network Code on Demand Response, as submitted by ACER on March 7 2025), in contrast to basic DNDPs which in some cases are merely lists of investments or network expansion plans.

Elements that such advanced DNDPs encompass are for example (non-exhaustive): information on how flexibility is integrated in scenario building and forecasts, how alignment and exchanges with TSO network planning take place and how flexibility implementation is considered next to grid reinforcements. Section 6.1 provides a table with example elements of what an advanced DNDP entails for each of the design categories.

3.1. Design categories

DESIGN CATEGORIES FOR 1. Regulatory regimes and practices for the design and implementation of DNDPs

The first subtopic comprises five design categories. The first two, namely the update frequency and technicality of DNDPs, describe the overall outline of the DNDPs. The third and fourth design categories cover the heterogeneity within a MS between DSOs. They illustrate harmonization and/or standardization measures between DSOs and possible exemptions for certain DSOs. These design categories are therefore especially relevant in the case of heterogeneous DSO landscapes with multiple DSOs of different sizes, where trade-offs between administrative burden and added system value may arise. The last category lists elements of the DNDP, which translate the identified grid development need into actionable measure for the grid development (e.g. grid congestion map, investment plan).

[17] European Commission. 2 June 2025. Commission Notice on a guidance on anticipatory investments for developing forward-looking electricity networks.

1. **Update Frequency:** The Electricity Directive mandates at least a biennial update of DNDPs to ensure compliance (Article 32). We examine to which extent this is the case and contextualize this fact with the planning horizon applied in the DNDPs.

2. **Technicalities of DNDP:** Three technical aspects of the DNDP outline are covered. First, regarding the public availability: DNDPs must be made publicly accessible, though this varies by MS. Second, the length of DNDPs can vary, indicating the level of detail of the planning (e.g. covered voltage level). Third, the accessibility of the DNDPs depends on the language, in which they are provided. DNDPs are typically available in the national language(s), with additional translations into widely used languages such as English.

3. **Harmonization Within a Member State Between DSOs:** The level of coordination between DSOs in developing DNDPs is critical for harmonization within a MS. A standardized DNDP template or a list of required information may be provided in order to ensure consistency. This template can be mandatory or optional, depending on the regulatory framework. In countries with multiple DSOs, coordination efforts are often supported by national regulatory authorities (NRAs), ministries, or DSO industry associations. These entities may produce summary documents highlighting key outcomes and impacts of various DNDPs. In some countries, these summary documents may be required to represent smaller DSOs, which are not required to report in individual basis (see next design category).

4. **Minimum Requirements for DSOs to Develop a DNDP:** According to Article 32(5) of the Electricity Directive, the MS can decide to apply the de-minimis threshold of the 100,000 customers per DSO as threshold for mandatory development of DNDPs. We examine how this is applied, especially in MS with many DSOs.

5. **Actionability of DNDP:** For DNDPs to be actionable, they may include critical elements such as grid congestion maps, investment plan, and other relevant data are essential components that enhance the utilisation of DNDPs.

DESIGN CATEGORIES FOR 2. Procedural steps, data collection and governance of DNDPs

While the first set of design categories above outlines the formal requirements of the DNDPs as set in each MS according to level 1 and level 2 framework conditions, the second set of design categories considers the processes and responsibilities. This includes the timeframe and geographical scope, such that the following design categories describe the interaction with key stakeholders and their roles.

1. **Administrative and Regulatory Procedure:** Nationally set requirements typically determine the procedural framework for DNDPs, i.e. whether/to what extent the development of DNDPs is already mandatory at lower grid levels, in which timeframe it needs to be created, and which geographical coverage is required (e.g. based on planning regions). These elements ensure clarity regarding the timeframe, scope, and procedures that go into network planning.

2. **Governance Structure:** The governance structure defines the involvement of the NRA and other government bodies in the DNDP process. While the submission of the DNDP to the NRA is defined by Electricity Directive Article 32 (3), the further specification of the NRA's role is determined nationally, i.e. whether the NRA may/must approve, comment, or simply be informed. In some cases, formal approval is required by other entities, especially where processes for DNDPs are new or in formation.

3. **General Stakeholder Engagement:** According to Electricity Directive Article 32 (4), the DNDP should be consulted by all relevant system users and the relevant transmission system operators, with consultation results published and submitted to the NRA. We examine how MS consult with the stakeholders to involve and whether the consultation is public or private, which may be subject to previously established national processes despite an increased push for transparency from the EU level.

4. **TSO Alignment and Exchange:** For the high-level objective of an integrated, consistent network planning, the DSOs should align their activities with the ones of the TSOs. This is ever more important from forward-looking perspective, as if investments are not aligned and well-coordinated, network strengthening at DSO level may not be fully utilized e.g. due to constraints at the TSO level. To this aim, the study focuses on the current use of scenarios and assumptions to identify network development needs and the coordination between TSOs and DSOs on a national level. In line with the EU Grids Action Plan, this includes data exchange practices.

DESIGN CATEGORIES FOR 3. The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings

The final set of design categories clarifies to which extent the DNDPs consider measures to meet the future needs of the distribution grid (already as part of the applied scenarios, i.e., an expected or envisaged development, or as a measure being the result of the scenario analysis and complementing grid reinforcements).

1. **Scenario Building and Forecasting:** The design category clarifies the basis of scenarios for load and production forecasts and their alignment to national policies (e.g. NECP), international energy outlooks, or other policy targets. Thereby, it looks in particular at the depth and coverage of data-driven network planning and the alignment between grid levels.

2. **Flexibility Forecasting:** The design category identifies which technologies are considered as flexibility sources in the forecasting and how. Potential flexibility sources are electric vehicles (EV), heating, ventilation, and air conditioning systems (HAC), energy storage, and production curtailment.

3. **Kind of Proposed Measured as Results of DNDPs:** Grid reinforcements are a common measure to further develop the grid to meet its future needs. The Electricity Directive Article 32 (3) requires DSOs to also include more innovative measures, such as demand response, energy efficiency, energy storage facilities or digital and smart technologies. We examine the extent to which this takes place in the MS, focusing on the explicit reference to alternatives for network expansion through grid-enhancing technologies or principles for prioritization of different measures. Examples could be use of dynamic line rating, implementation of on-load tap changers at transformers, or broader activation of flexibility services (e.g. via flexibility markets or dynamic contracts).

3.2. Analysis

1. REGULATORY REGIMES AND PRACTICES FOR THE DESIGN AND IMPLEMENTATION OF DNDP

The current scope and depth of network development planning at distribution level is highly heterogeneous across MS. The documents provided by (and required from) DSOs are best described as a range of documents from list-like investment plans to fully formed DNDPs. Hence, the planning documents differ by intended *outcome,* with repercussions on contents and comparability.

For practical purposes, we use the term DNDP to refer to all planning documents prepared and published at the distribution grid level. In reality, many MS have different terminology that reflects the current content and scope of the national requirements. These can be called network expansion plans, investment plans, development plans or even differently. This is also given by missing full transposition of the requirements of the Electricity Directive in some geographies. In these cases, the methodology is often not covered in the plan and sometimes also not transparent in national legislation (e.g. CZ). In other cases, the plans exist but are mostly not publicly available in the absence of such an obligation (e.g. ES[18]). In this context, it is also noteworthy that several MS are

[18] With one exception for i-DE Grupo Iberdrola, who do publicly publish a DNDP: i-DE Grupo Iberdrola. 2025. https://www.i-de.es/i-de-grupo-iberdrola/conocenos/plan-inversion-informacion-redes.

in the process of expanding their requirements. Examples for far-reaching ongoing revisions include the cases of DE and PL. With this point covered, the findings of the design categories are summarized below.

Regarding the **update frequency**, the biennial updating is standard practice (occurs in 20 MS), but some (7) MS have additional shorter horizons for investment plans or updates (e.g. RO, HR). The documentation indicates that these provisions serve to allow more agility to cope with changing macroeconomic and grid conditions alike.

When comparing the **technicalities and formalities** of the DNDPs, there is a large range in the length and scope of the documents, both within MS (different DSOs) and across MS. The provided plans range from 3 pages to over 200 pages (up to 1.000 pages incl. annexes) for a single DSO. However, in some case this arises because the methodology and calculations are part of a separate process, so the number of pages / contents in the DNDP is not necessarily a suitable indicator for quality of the overall planning process. These practices relate to the point of how to define an "appropriate" DNDP.

In MS with multiple DSOs, the range is also broad (e.g. SK, BE). Plans are typically only available in the national language, but some MS provide summaries or highlights also in English (e.g. DK, SK). FR can be considered a best practice with the full (preliminary) DNDP available in English. In 24 MS, the plans are publicly available. An interesting observation is that some restrictions to availability seem to be motivated by references to trade secrets and critical infrastructure, but this is anecdotal rather than systematic in national regimes. In addition, the different practices of defining DNDPs or splitting investment lists from methodology documentation hampers the transparency and access for a proper comparison.

The same point applies to the situation of MS with many DSOs, where in many cases DNDPs are not centrally collected, although they typically must be submitted to the NRA and in some cases also to the TSO or Ministry (e.g. BG, SK, PT). Overall, the harmonization within MS is relatively low.

Two main pathways are present in terms of **harmonizing DNDP structures** across DSOs in a MS: 1) In some MS national legislation or network codes prescribe which topics to cover and/or structure to use (e.g. FI, NL) – albeit in differing levels of detail, or 2) In a few MS a mandatory template document or questionnaire is provided by the NRA (e.g. AT, DK, EE, PL, PT). In total there are 15 MS (among the MS with more than one DSO) where some form of guidance is provided, while in 3 such MS do not provide any form of common structure. Efforts in terms of harmonizing DNDP structures can be considered a good practice as it contributes to harmonization across DSOs and facilitates requests for information on specific topics of interest. Most planning activities occur at the level of the individual organizations (DSOs, in some cases regionally). There is often no aggregated document that combines the DNDPs from the different DSOs. In absence of aggregation of multiple DNDPs into one national level DNDP, in some countries the NRA does provide a report or letter to government in which main insights of the various DNDPs are aggregated.

The heterogeneity in the technicalities is unsurprisingly reflected in the **contents of DNDPs** across and within MS, which vary widely. Summarizing the common practices, it appears that investment and expansion planning are almost always in, but for the more novel aspects of distribution network challenges arising through the energy transition, there are large differences. Overall, AT and most Nordic countries serve as examples for progressive planning contents. The following practices showcase the discrepancies and extract factors that better describe the differences.

Gaps between current practices and advanced DNDPs:

- List-like simple plans that focus only on investments or network expansion (e.g. CZ in contrast to plans also considering alternative options as leveraging flexibility potential.
- Lower grid levels not or only barely treated (e.g. LU, HU) in contrast to plans also tackling the low voltage level on a suitable level of detail (e.g. by prioritizing or by using a suitable output format)
- Lack of alignment across DSOs (e.g. PL, but this is under revision, CZ, RO) in contrast to well aligned plans in terms scenario development, methodology and outputs

However, it should be noted that the current practices are subject to revision. Many MS are about to change and expand the DNDP processes, both through revisions of national legislation and through increased integration and coordination between DSOs, TSOs and NRAs. While the stocktaking shows large gaps to the ambitions outlined in the Grid Action Plan, there is decidedly work in progress.

Selected practices in developing advanced planning procedures:

- Including flexibility in detail (e.g. AT)
- Including customer service projects (e.g. LT, CY)
- Harmonization of DNDP structure, content and scenarios across DSOs (e.g. NL)
- Discussing potential solutions for challenges (e.g. DK)
- Looking at the long-run: Risk analysis (e.g. PT) or analysis of long-term performance (e.g. FR)

Generally, these selected practices reflect heterogeneity in the extent to which the changing role of distribution grids is already reflected in network development planning. Some MS are ahead in this regard and are already covering aspects that are further defined in the proposal for a Network Code on Demand Response that was submitted by ACER on March 7th 2025.[19] This links to the different depth in treatment of future needs and changing grid user composition (see topic 2 as well). Many of the selected practices are therefore somewhat related to how forward-looking the DNDPs and related procedures are to date. Still, there are differences in how this is regarded: (a) by considering technology diffusion (more common), or (b) by explicitly considering the use of flexibility (underdeveloped to date).

In the above, heterogeneity comes across as negative. However, there are also cases where MS differ from the common practice because they tailor the DNDPs to their specific challenges and key factors for future success in light of national grid conditions and economic challenges. Examples include:

- NL with a strong focus on treating network constraints (specific chapters for this in the DNDP)
- LT with a focus on market measures / empowerment (large dedicated section)

In addition, heterogeneity is also driven in some cases by a focus on the particular conditions of a certain geographic area, thus reflecting differences in complexity. For example, HU has a particular chapter for the Budapest area. DE uses six regional planning scenarios for this reason, to which the respective DSOs are bound to contribute (with exemptions for small DSOs). Another differentiation is applied regarding the **size of DSOs and their respective requirements**. Some MS have chosen to apply the exemption possibility for small DSOs as mentioned in the Electricity Directive Art 32(5). For small DSOs, thresholds are commonly set either by the number of metering points or by the number of clients/customers, which need not be the same. PT appears to be a special case with

[19] ACER. (March 11, 2025). New network code on demand response will further advance the energy transition. [Annex I]

different conditions for the lowest grid level (e.g. small DSOs do not need to adhere to the template that is provided to the bigger DSOs, but receive special guidelines).

To some extent, the external conditions for smaller DSOs are indirectly covered by **common planning scenarios** (e.g. DE) or summary documents published by the NRA (e.g. IT, NL). However, this information does not involve grid development measures. The way in which MS treat the network planning of such small DSOs varies greatly. In LU one of the small DSOs has reached out to the biggest DSO (Creos, covering >95% of connections in LU) with the question whether Creos could do the network planning for them. Similarly, in EE network planning by a bigger DSO for a smaller DSO already takes place, although it should be noted that both DSOs are part of the same group company.

Three main avenues of **DNDP actionability** are identified in the MS research:

- (a) transparency of investment plans (available in 19 MS), leading to financial actionability,
- (b) the availability of capacity maps (available in 22 MS), leading to actionability at spatial resolution, and
- (c) consequences on the regimes for grid connections

Few MS are acting along all three avenues jointly, although capacity maps are becoming increasingly widespread (see also Chapter 5 on grid connections). Regarding the investment plans, it is difficult to judge quality given that the information ranges from lists by substation to interactive representations / tools. Good practices with high granularity appear to be already implemented in AT or DK for example, both of which have very detailed information available.

2. PROCEDURAL STEPS, DATA COLLECTION AND GOVERNANCE OF DNDPS

While all MS specify the **administrative and regulatory procedures** in some way, there are large discrepancies regarding the depth of these requirements. These can be summarized along three dimensions. First, the geographical coverage / structure of the DNDPs. In most MS, each DSO is responsible for the planning in its own service area and these plans remain separate. Some MS have different arrangements that require closer coordination (e.g. DE, BE). Still, the resulting documents are rarely aggregated to a national plan, with the notable exemption of SI, where the DSOs contribute to a single national DNDP. Second, the timeframes and milestones of the processes differ widely. Typically, the deadlines for submission are late in the calendar year, but this is not uniform. Similarly, the spacing of different steps and approval processes varies widely across MS, and it is not always transparent how these procedures are implemented in practice. In some MS, the submission and publication deadlines for the scenario development and DNDP are aligned with the TSO planning (e. g. DE, NL). Third, the scope of the requirements differs. In many MS there are specific requirements on what the plans have to contain, but in other cases the requirements are focused on the administrative process. PT is a case of very developed requirements and high transparency.

In this context, the question comes back regarding what constitutes a "distribution network development plan". Several MS do not have fully developed DNDPs at this stage (see **Infobox 2**), meaning that the distribution-level plans are more narrow or less extensive than the national plan handled by the TSOs. As mentioned before, the terminology around the "planning documents" differs as well.

Typically, the **governance** structures specify that the NRA is the responsible party for receiving and approving the DNDPs. In all 27 MS the DNDPs are submitted to the NRA. After submission, plans are usually reviewed, the NRA can request modifications or more data, and ultimately approves. However, there are deviations, where other institutions are the primary approval point (e.g. competition authority, or TSO). Regarding further involved stakeholders, Ministries are often notified, but it is less common for them to have a formal role. Best practices emerge in involving Ministries for better alignment with broader policy goals. Examples concern two policy areas: (a) energy and climate, (b) infrastructure. SI is an example of a procedure where government bodies from both infrastructure and climate are considered explicitly. Typically, this occurs at national level, but for example in GR, infrastructure-related involvement includes local authorities as well. An advanced institutional solution is found in PL, with a task force initiated by the president of the NRA under a national Charter.

Regarding **general stakeholder involvement**, not all MS documents specify a (public) consultation. In 22 MS public consultation of the (draft) DNDPs takes place, while in 5 MS public consultation does not take place. At the same time, however, it is also not clear how much interest there is in the consultation. Anecdotal evidence from DE suggests that there is little public input from the consultation. There are also differences in which stakeholder conducts the consultation, i.e., the DSO themselves or the NRA. The extreme case is HR, where there is a two-step consultation process split between DSO and NRA. Another example is FI, where some DSOs cooperate voluntarily with municipalities, telecommunication companies and other significant stakeholders in their operating area. Caruna Espoo Oy, one of the Finnish DSOs made use of a stakeholder specific online-survey and gave the possibility for verbal feedback. Customer service helped with problem solving. With this approach, they got input from approximately 3,000 participants.

Current practices on **alignment and data exchange between TSOs and DSOs** are highly heterogeneous and tackle different levels of alignment:

- (Regional) Scenario development
- Applied methodological approach and principles
- Output (in case distribution and transmission development are linked e. g. due to close geographical proximity or interconnections between the voltage levels)
- Development / publication schedules (i.e. biennial plans of TSO(s) and DSO(s) in different years, same for scenario framework)

In many MS, there is some reference to TSO-DSO exchange and alignment with the TYDNP, but there is no consensus and also little transparency on how this translates to the procedural steps. In some cases, data are provided, in others forecasts are shared or even binding as a basis. A good practice is the alignment between TSOs and DSOs for a more integrated plan in NL. In some MS, this is a non-issue with no additional provisions because there is only 1 TSO/DSO (e. g. MT with no TSO, LU where TSO is also biggest DSO). An emerging best practice is the use of detailed **common methodology** and analytical framework that is shared from the TSOs down to the DSOs (e.g. in SE, FR). On a related point, the use of smart meter data is not a common practice at DSO level to date. However, some MS have set up processes and specified timelines for increasing the use of / access to smart meter data for network planning (e.g. SI, SE, EE).

3. THE INTEGRATION OF RENEWABLES, THE DEVELOPMENT OF CHARGING STATIONS AND THE ELECTRIFICATION OF HEATING AND COOLING OF BUILDINGS

Regarding the **scenario building and forecasting**, there is a wide range of modelling tools and approaches being applied. Typically, MS apply a common model with several national scenarios under the same framework as the basis for scenario building among DSOs. Good examples for this approach of a streamlined, common procedure include FR and FI. A more agile approach is taken in AT, where several different data types and methods are combined and applied. Overall, four groups of scenario types can be identified. In the simplest form, scenarios rely mainly on historical data and extrapolate trends (e.g. LT). The second group is to rely on demand forecasts based on predicted consumer behaviour (e.g. EE). The third group builds on national level targets as set out in the NECP (e.g. IE, PT). Most MS use some combination of scenarios built from these three groups, although the number, scope and method to scenario building differs and is typically not detailed in the DNDP itself. The fourth group is building directly on EU-level targets, which appears to be less common. For example, in IT, the scenario building refers to the EU "Fit for 55" plan for one of the options. These approaches are not mutually exclusive for all MS. Many MS work with a range of scenarios covering multiple approaches from those four groups outlined above.

Some MS add particular aspects that are not common practice but rather qualify as particularities. Notable examples include:

- Drawing on sector-specific expertise for EV development in NL
- Including a socio-economic perspective to compare options in SE

- Consideration of a dedicated “crisis” scenario in LV

Against this background, the outcomes of the DNDPs are commonly focused on grid reinforcement as the dominant measure. In addition to this, technological innovations and flexibility measures are being piloted and tried, but not implemented at scale across Europe. There are broadly speaking three ways in which **technology and flexibility measures** is being considered in DNDPs, listed here by increasing complexity:

- Technology additions (e.g. sensors to allow for dynamic line rating, implementation of on-load tap changers at transformers)

- Market development of flexibility (e.g. integration of commercial storage in electricity markets)

- Flexibility actively used for grid relief (e.g. activation of demand response by DSO)

Many MS already consider the first category of technology additions. It should be noted that technology additions are already applied in several MS, but that these are **not always mentioned explicitly in the DNDPs**. Application of dynamic line rating is for example implemented in several MS (e.g. LU, SI, RO, SE), but it cannot always be derived from the DNDPs. This finding emerged from contrasting the desk research and the conducted interviews.

In terms of flexibility considerations, most common is the **modelling of EV uptake and HAC** technologies with regional differences in which technologies are considered and in what detail (more heat in the North, more cooling in the South). Storage is also commonly considered, although the technologies differ: e.g. commercial storage, pumped hydropower, and batteries, sometimes including EVs in this category). Less common flexibility options are for example the inclusion of hydrogen / electrolyzing (e.g. SE, DK) and power-to-gas / heat (NL). Overall, the scope and complexity of including these forecasts differ across MS but tend to reflect the national priorities and the data available, which appears correlated with broader policy progress in the respective MS.

Market-oriented flexibility development is less commonplace and tends to be subsumed under demand response with varying depth of the forecasts or models. Examples in this category are demand response from industry (e.g. NL), data centres in the Nordics (e.g. SE), and Vehicle-to-Grid (e.g. DE). In several other MS, there are national requirement that DNDPs should contain flexibility (e.g. AT, HR), but these are typically not specifying the technologies to consider, and currently available documents indicate that these provisions have not been fully implemented to date. For the third category, the active use of flexibility is being mentioned to be used for grid relief in congestion cases (short-term) or as an alternative to grid expansion (more long-term). Several MS have pilots (e.g. FR, EE), but this advanced use of flexibility is not widespread to date. There is some evidence of MS conducting studies in this direction for specific local areas, but these cases also indicate that available flexibility may not be usable for the DSO under current national frameworks (e.g. LT)

Regarding the methodologies, there are some knowledge gaps that arise from documents not being shared or referring to internal studies that make a structured comparison difficult. This then also raises the question whether cases with relatively simple procedures are more driven by constraints to implementation in operative processes or feasibility for the DSOs per se.

When it comes to the **solution space**, as mentioned before, grid reinforcement and expansion are still the primary means. Especially in the CEE countries that joined with the EU Enlargements after 2004, there is also a strong focus on modernisation, which goes hand in hand with better energy efficiency (e.g. SK). Beyond this, the MS differ widely in the items they consider, and often the relative importance of different strategies is not apparent. These differences reflect *what* is being targeted (e.g. flexibility, congestion management), but also *how* this is supposed to be tackled (e.g. contractual arrangements, investments in smart grids).

In MS with multiple DSOs, there are even cases for different priorities across DSOs (e.g. FI), which seem to reflect geographic factors. There are several examples for innovative strategies or principles that could serve as best practices:

- Financing incentives to research specific alternatives to reinforcement in FI
- Project to streamline management of flexibility resources in AT
- Regional renewable master plans with cost sharing among stakeholders in FR
- Use of innovative chargers for voltage regulation in SI
- Market integration strategies to optimize power flows between surplus and deficit areas in SE

Some novel strategies do not fit a particular design category. The agile investment framework that IE has put in place is an example of an approach that aims to balance planning and investment certainty with the possibility to adjust and manage based on changing framework conditions. However, there are many cases where current practices are under revision and the extent to which this leads to higher quality and more integrated planning in practice is not clear at this stage although the revisions do indeed target several of the current shortcomings.

3.3. Selected practices for deep dives

The analysis above has portrayed the overarching insights that the MS research has put forward. As a next step, this section highlights selected practices that could potentially be transferred across MS. Integrating insights from the three subtopics presented in the previous section, we bring forward three key priority themes that are interesting and relevant to consider in more detail by means of these practices, as these priority themes have the highest possibilities for improvement and highest relevance in terms of advancing network planning.

1. **Harmonization** (combination of design categories 'Harmonization Within a Member State Between DSOs' and 'TSO Alignment and Exchange')
2. **Actionability** (combination of design categories 'Actionability of DNDP' and 'Kind of Proposed Measured as Results of DNDPs')
3. **Flexibility integration** (design category 'Flexibility Forecasting')

The sections below illustrate multiple deep dives selected in terms of topic–MS combinations. These selected practices could be transferred across MS contexts and foster efficiency, effectiveness and innovation in terms of further developing network development planning approaches that are appropriate for the changing needs of the distribution grid.

1. HARMONISATION (BETWEEN DSOS AND WITH TSO)

The research indicates substantial differences in harmonisation levels, but does not yet give a clear picture to what extent the differences are driven by national circumstances and grid conditions (incl. DSOs organizational capacity), or by lack of harmonisation and gaps in implementation that could be addressed through policy. For MS with many DSOs, it is also not clear how appropriately the responsibilities are distributed between national institutions and DSOs. Towards further assessing best practices related to heterogeneity, the focus will be on (lack of) harmonisation within MS between DSOs and between DSOs and the TSO(s), as national alignment between system operators is key to approach network planning in an integrated manner. Two deep dives are pre-selected for this priority theme, as described below.

Harmonising network development planning in Hungary

Context: In Hungary, one integrated TSO-DSO network development plan (NDP) is developed, which encompasses the networks of the TSO (MAVIR) and all DSOs. This plan is developed through continuous alignment and data exchange between the TSO and DSOs, serving as a best practice. The main elements of the methodology and document structure are outlined in the Operational Code, providing a clear framework for the development process. Network licensees prepare their plans simultaneously under the leadership of the TSO.

Content: The integrated plan includes scenario-based development strategies, system-level testing, and investment planning that incorporate both transmission and distribution needs. DSOs contribute detailed forecasts on consumer demand, renewable integration, and infrastructure constraints, which are then integrated into MAVIR's system-wide modelling and stability assessments.

This harmonised approach integrates distribution developments into transmission planning through joint evaluations of voltage control, short-circuit resilience, and load growth. The document also outlines joint infrastructure projects (e.g. substation upgrades) that respond to both transmission and distribution challenges, particularly in concentrated demand areas like the Göd Industrial Park. Planned investments are detailed for each network operator, although other than high- voltage levels (below 132 kV) are not regarded in detail. This could be an opportunity for further improvement.

Evaluation: Hungary's integrated NDP highlights the value of close collaboration and continuous exchange between TSO(s) and DSOs throughout the network development planning process. Rather than prescribing a single integrated report to be developed in every MS, the key lesson is the way of working of structured cooperation, transparent data sharing, and joint scenario development. This joint development process facilitates improved transparency, better alignment of investment priorities, and an accurate representation of transmission as well as distribution system needs.

Harmonising network development planning in Germany

Context: In Germany, harmonization of network development planning between DSOs is highly relevant, due to the heterogeneous DSO landscape with more than 800 DSOs in total of which about 80 are required to develop a DNDP. In order to coordinate the planning processes, each DSO is assigned to one out of six zones, so called planning regions. This coordinated action is obliged by German law (Energiewirtschaftsgesetz - EnWG 14d).

Content: The DSOs in a planning region create a regional scenario in alignment with the four TSOs as a common basis for the distribution network development plans of the individual DSOs. The scenarios consider the probable developments for the next five and ten years as well as the long-term perspective of a fully decarbonised energy system, the binding target for 2045. Small DSOs (which are exempt from issuing their own DNDP) still need to support the DSOs with the obligation to develop a DNDP in their planning region. The regional scenario needs to be submitted to the NRA ten months before the submission deadline of the DNDP. The scenarios need to include the following:

- Information on the existing, expected and maximum possible connections of the various generation capacities and loads
- Information on the expected injection and withdrawal
- Assumptions regarding the development of the transport sector and the expansion of publicly accessible charging infrastructure
- Assumptions regarding the development of the building sector, in particular with regard to the expected heat consumption and the type of heat supply, taking into account the results of heat planning, as well as
- Assumptions regarding the development of other sectors.

DSOs falling under the de minimis regulation are required to submit relevant data for the regional scenarios to the respective upstream DSO. They also need to be enabled to give their opinion on the requirements for the requested data set by the DSOs with reporting obligations (EnWG 14d (9)).

The DSOs have published the scenarios for the six planning regions in 2023 for the first time on their digital platform www.vnbdigital.de, which also offers all DNDPs for download. They are linked to the existing scenarios for the grid development plan of the four TSOs (for 2030, 2037 and 2045) which had to be interpolated for the DNDP planning years 2028 and 2033. The regionalisation of the loads and generators is also linked to the existing TSO scenarios but the regionalised numbers have been adjusted to also reflect the targets of the individual municipalities and DSOs and to allow a more detailed regionalisation necessary for the distribution grid level. The common regionalisation was focused in some cases on the most relevant drivers of the future energy system development (e. g.

Onshore wind, PV, EVs, heat pumps, H2 electrolyser and conventional power plants). The published scenario documents usually only figures on the level of the planning region.[20]

Evaluation: The DSO landscape with about 80 DSOs with the requirement to develop and publish a DNDP and in total more than 800 DSOs is exceptional in Europe. However, the well-structured approach can serve as a good example for other MS as well. In general, in MS with multiple DSOs, alignment between all DSOs on a harmonised scenario is ideal to ensure a unified approach for the scenario basis and the regionalisation of the expected load and generation capacities. The requirement for all DSOs in a planning region in Germany to develop a common framework ten months before the submission deadline of the DNDP can serve as a best practice example. In the exceptional case of Germany, splitting the harmonisation process into multiple regions, seems a reasonable way to not overcomplicate the harmonisation procedure, allowing all DSOs in a region to get involved in the discussion and definition of the scenario. This could also be practiced in MS with about 10 DSOs or more. In Germany, the alignment with the TSOs and their transmission grid planning scenario as the common basis for the distribution grid planning scenarios ensures also an alignment on a common scenario basis between all DSOs on a national level.

However, first evaluations of the process in Germany show room for improvement of the process. Although the procedures in the planning regions have been similar, the harmonisation beyond the planning regions could be further harmonised, e. g. the methodology to define the scenarios incl. the regionalisation process which followed slightly different approaches between the regions. Furthermore, the law requires the DSOs of a planning region to coordinate the fundamentals of network expansion planning. However, it is not further defined if this also includes the methodology of the DSOs to assess the need for grid reinforcements or only the underlying scenario. There might also be further room to better include the over 700 DSOs without the requirement to develop a DNDP in the process. Despite the national legal requirements, one regional plan states that they generally assume that the developments of downstream DSOs are incorporated via already existing, individual regular planning meetings and details of the practical processes remain unclear.

2. ACTIONABILITY

The research gives an overview of tools and approaches that help towards the implementation of network development actions. The comparison however indicates that actionability has only a minor role in current DNDP practices and is typically not elaborated in detail. There are common output formats, especially grid capacity maps and details on planned investments. Further developing best practices can allow for improved usability and application of the DNDPs.

Actionability of DNDPs in the Netherlands

Context: Grid congestion is a pressing issue in the Netherlands. As a result, several actions that are described in the DNDPs of the Dutch DSO are specifically focussed on dealing with congestion. In parallel, a 'national action program congestion' (in Dutch: Landelijk Actieprogramma Netcongestie, 'LAN') has been established, directing actions at faster grid development, optimisation of current grid capacity, and deeper data insights.

Content: One of the key solution areas that is mentioned in the DNDPs and the LAN is directed at new types of contracts that DSOs want to be able to offer to customers. Two specific contract types are highlighted: group transport agreements and (group) capacity limitation contracts. A group transport agreement is a contract in which a group of companies jointly uses an agreed transport capacity. An example of this would be an industrial area in which several companies have the opportunity to shift part of their electricity consumption in time. By coordinating peaks in energy consumption and generation, the group can more efficiently manage the available transport capacity. Capacity limitation contracts consider (a part of) the contracted transport capacity as flexible. In such cases, the connected party can only use a certain (higher) level of capacity when the DSO indicates that sufficient capacity is available.

Furthermore, additional congestion management approaches are mentioned, cable pooling (one connection for a combination of solar and wind generation assets) is implemented, and flexibility

[20] Based on the regional scenarios for the planning regions “Mitte”, “West”, and “Ost”

markets are used (for various purposes, i.e. congestion management). Additionally, detailed investment plans at substation level are provided in the DNDPs, and capacity maps are available online.

Evaluation: Including specific actions for congestion relief / management in the DNDP is not relevant for all MS but can be a valuable best practice for other MS with (upcoming) pressing congestion issues. Developing a national action program for congestion (the 'LAN') could be a relevant measure that is transferable to other MS as well and could help to more effectively operate the grid and also reduce grid expansion needs. It encourages sharing of ideas between DSOs and between other stakeholders and ensures that independent of the DSO that a grid connected party is connected to the party can make use of such proposed solutions (if they can be made available at the national level).

Actionability of DNDPs in Germany

Context: In Germany, similar to the explicit requirements that legislation states in terms of scenario information (see 'Harmonising network development planning in Germany' above), legislation also states several explicit requirements that relate to actionability of DNDPs.

Content: EnWG 14d (4) requires DNDPs to encompass

- Grid maps of the high-voltage and medium-voltage grid and the medium-voltage and low-voltage substations with the constrained regions of the respective grid, including a detailed description of the constrained line sections.
- The planned optimization, reinforcement, renewal and expansion measures as well as necessary energy efficiency and demand-side management measures in the next five and ten years
- Information on the planning- and permitting procedures to implement these measures,
- A description of the expected development of the distribution task up to 2045
- The need for non frequency-bound system services and flexibility services (i.e. congestion management) and the planned coverage.
- Information on the need for public planning or approval procedures for these measures, their current status, and information on investment decisions and expected implementation timelines by the DSO.

Hence, the legislator defines the voltage levels and type of measures incl. efficiency and flexibility measures to include in the analysis. Furthermore, the output format is defined with clear expectations on information for the individual measures identified.

Usually, the DSOs in Germany have used a table format to summarise their results, often going beyond the required information. They can cover: name of the individual measure, a short description, category (e.g. substation, new line in new or existing route, replacement) location or start- and end-point, the respective voltage level, length, change in transport capacity, reason, solving current or future congestion, optimal date of realisation, expected start of construction and start of operation, reason for a delay, investment costs, current status and status of permitting phase and tested alternative measures[21].

Evaluation: The legislative requirements as well as the actual implementation ensure a detailed planning with an overview on potential and concrete investment decisions and allows all stakeholders

[21] See for example the DNDPs of Westnetz GmbH and E.DIS Netz GmbH

and the public to transparently access the planning and taken investment decisions of the DSOs and can serve as a best practice for other MS and DSOs in the EU.

Actionability of DNDPs in France

Context: France's approach to distribution network development planning (DNDP) is characterized by a strong collaboration between national and regional actors through the establishment of so-called S3REnR (Regional Renewable Energies Connection Master Plans) schemes. These strategic frameworks for integrating renewable energy into the grid are developed for each of the 18 administrative regions of France, under the mandate of the Grenelle II Law (2010).[22] The development of these S3REnR is coordinated by the transmission system operator RTE, in cooperation with the distribution system operator Enedis and the regional authorities, under the control of the national regulator (CRE). The goal is to both adapt the regional and national energy transition goals, while minimising the costs for grid expansion and integration on a local level.

Content: The S3REnR are based on an anticipatory assessment of the future grid needs for the integration of an expected production capacity from renewable energy (RE) based on pre-announced and estimated projects which serves to model grid constraints over the coming 10 to 15 years for each region. The schemes intend to identify the most cost-efficient solutions to implement the necessary adaptations of the network by either optimising the existing infrastructure through various flexibility solutions, or if not sufficient, by reinforcing the grid or creating new infrastructure on the distribution or transport network level.[23] Based on the current and planned connection capacity for each substation, the S3REnR enables the reservation of connection capacities by RE projects over a 10-year period, giving a priority over conventional electricity projects.[24] This guarantees RE project developers that the required infrastructure is already available or shortly being implemented and is reserved for the specific project once the project is planned and submits an official grid connection request (Offre de Raccordement de Référence – ORR).

In addition, the S3REnR estimates the overall costs of network expansion to increase hosting capacities from RE, and introduces the principle of shared cost investment, allowing parts of the actual grid integration costs ("quote-part") to be shared among producers. Indeed, some of the integration costs for new network infrastructure serving multiple RE projects such as new substations, transformers and their connection to the distribution or transport network, are covered through the quote-part which is paid by electricity producers (for projects above 250 kVA) in addition to their individual connection costs. Therefore, the quote-part incentivises the clustering of projects, as it only entails a coverage for commonly used network infrastructures.[25] Other grid integration costs, such as the reinforcement of the transmission grid not directly linked to new RE projects, are covered by the TURPE (Tarif d'Utilisation des Réseaux Publics d'Électricité) which is mainly paid by consumers and to a lesser extent by producers (for the injection of electricity) and not pooled via the quote-part.

The specificity of this quote-part is its underlying cost sharing mechanism. Once the costs for the creation of new and shared grid integration infrastructure for the connection of RE projects has been estimated for a specific region, the system operator calculates a uniform fee in EUR/MW which is the same for all RE projects in this region, regardless of their location or time of connection, within the timeline of a S3RenR. The calculation methodology is based on several parameters, among which the expected investment costs by the system operator, the expected costs related to development of studies and procedures for the dimensioning of these infrastructure and the total new connection capacity needed within a region. Thanks to the anticipatory and shared cost mechanism for new infrastructure, a RE project developer has less of a first mover disadvantage in terms of connection

---

[22] RTE. N.d. Les Schémas Régionaux de Raccordement au Réseau des Énergies Renouvelables : des outils stratégiques https://www.rte-france.com/projets/s3renr

[23] RTE. 2021. Link : Deliberation N. 2021-23.

[24] RTE, Enedis, Sicae, Gazelec. January 2024. Link : Révision du schéma régional de raccordement au réseau des énergies renouvelables (S3REnR) de la région Hauts-de-France.

[25] RTE, Enedis, Sicae, Gazelec. January 2024. Link : Révision du schéma régional de raccordement au réseau des énergies renouvelables (S3REnR) de la région Hauts-de-France.

costs as it knows where and when the additional capacities are planned.[26] Once the connection capacity has been saturated or it has been requested by the parties, a S3REnR and the price of the quote-part can be revised, integrating the cost of difference between the estimated and the actual revenues of the actual quote-part in the period of the last S3REnR period, accounting for forecast errors of that scheme.

Evaluation: As the quote-part is a reflection of the expected grid integration costs in a specific region to be paid by RE projects, the S3REnR performs a steering action on the optimised development of RE projects in terms of geography and planning. In regions with existing grid reserves or just low needed efforts to integrate new RE projects, the quote-part will be lower than in regions where the grid capacity needs stronger reinforcement efforts. This creates a pull effect for these regions, naturally steering the development of RE projects in areas with low grid development costs. However, it does not account for the overall system costs incurred from the dispatching of electricity or bottlenecks in transmission networks across regions. It also to be noted that the quote part may inadvertently disadvantage projects that do not share infrastructure but are otherwise well-sited in terms of resource potential.

In addition, the system operator publishes the current and future connection capacities for RE projects of the existing and planned stations, substations and connection lines. These capacities are published on the public platform www.capareseau.fr, which displays the total connection capacity for each substation and the creation of new lines, as well as the capacity for RE projects, categorised in terms of available, reserved and used capacity across all of France. This transparency fosters trust and coordination among RE developers, grid operators, and public authorities, and supports informed decision-making for project siting and investment. As such, other MS can draw lessons from this French approach, particularly regarding the benefits of anticipatory planning and accessible information for all stakeholders.

3. FLEXIBILITY INTEGRATION

The research shows that use of flexibility and even inclusion of flexibility in forecasts is still in an early phase. By further developing best practices in terms of flexibility forecasting and integration in DNDPs, as well as in terms of operationalising flexibility as an effective congestion management measure reducing the need for grid expansion, more steps to facilitate network planning to go beyond grid reinforcement can be taken. This can support DSOs in meeting their legal obligation to consider flexibility measures as alternative to grid reinforcements.

Flexibility integration in DNDPs in Denmark

Context: Denmark features a relatively high number of DSOs serving a small geographic area. By using a unified regulatory framework, a structured approach to flexibility has been put in place. Denmark already has a high RES share in electricity generation of 79.4% in 2023 (of which mostly wind). Additionally, its high uptake of electric vehicles and heat pumps, combined with the extensive coverage of smart meters, make it a suitable candidate for flexibility integration and use.

Content: In Denmark, DNDPs include forecasts on the potential availability of flexibility. These forecasts provide a rough expectation of how much flexibility might be accessible and how it could effectively postpone the need for network investments. DSOs use national forecasts from the Energy Authority which they can refine with local data. This already includes anticipated increases in various technologies such as electric vehicles, heat pumps, battery storages and electrolysers.

The DNDP template that is provided by the Danish Energy Agency[27] states how flexibility integration should be included in the DNDPs. This template is mandatory for DSOs to use. In the general 'Goal and purpose' section of the template, it outlines that in Denmark flexibility is increasingly seen as a

---

[26] Enedis. 1 October 2020. Link : Méthode de calcul des coûts prévisionnels pour les travaux de création ou de renforcement sous maîtrise d'ouvrage d'Enedis dans le cadre des Schémas Régionaux de Raccordement au Réseau des Energies Renouvelables (SRRRER)

[27] Energistyrelsen. N.d. Netudviklingsplaner

strategic alternative to traditional grid expansion, offering a cost-effective way to manage capacity constraints in the electricity distribution network. This section further elaborates on the relevance of flexibility and defines the differences between *flexible electricity consumption* and *flexibility services.*

Then, in the DSO specific parts of the template, there are two chapters where DSOs need to individually report on flexibility use and forecasts. Firstly, there is a chapter where DSOs must describe which flexibility/products are currently used by the grid company, and what their expectations are for the future use of flexibility. Secondly, there is a chapter where DSOs must assess the total flexibility potential for their region broken down in MWh and MW across voltage levels (0.4 kV grid, 10 – 20 kV grid, and 30 – 60 kV grid) and across time horizons (1 – 2 years, 3 – 5 years and 6 – 10 years).

Next to the forecasting of flexibility potential, first ways of using flexibility are also already implemented in Denmark. DSOs use implicit flexibility tools, such as time-differentiated tariffs and non-firm / interruptible connection agreements. Additionally, a fully organized flexibility market does not yet exist, but is under development (on a national level), with expectations of both national and international frameworks emerging over time.

Evaluation: Denmark's structured approach to flexibility forecasting in DNDPs offers a best practice model that is replicable for DSOs in other MS. While a DNDP template is not used in every MS, still some form of common structure would be valuable in general (see also recommendations section 6.1). Including an exemplary table / format on how to include flexibility forecasts would allow for a harmonised approach to flexibility forecasting. In terms of active flexibility usage, the specific enabling conditions in Denmark (e.g. high RES share, high smart meter penetration, high uptake of EVs and heat pumps) may be less present in other MS, making such forms of flexibility usage implementation in other MS more challenging.

A possibility for improvement could still be to increase the granularity and scope of the flexibility forecasts, particularly by clarifying whether curtailment of RES (e.g. wind and solar) is considered, and by further splitting the forecasts in terms of type of asset (e.g. EV, heat pump, etc.). Additionally, accelerating the development of organized flexibility markets and establishing clearer mechanisms for valuing and procuring flexibility services would be a logical next step to move from flexibility forecasting to increased flexibility activation / usage.

Flexibility integration in DNDPs in Finland

Context: Finland's almost 100% smart meter rollout and widespread use of time-varying electricity tariffs provide a strong foundation for integrating flexibility. All electricity suppliers offer hourly dynamic pricing contracts, and about 11% of Finnish customers have opted into such contracts (leveraging flexible consumption to reduce costs).[28]

In addition, Finland has taken early legislative steps to promote the integration of flexibility into distribution network development planning. Since August 2021, Finnish national legislation obliges DSOs to include a plan in the DNDPs for using demand response, energy efficiency, energy storage facilities or other resources as an alternative to system expansion.

Content: Finnish DSOs incorporate flexibility into their scenario analyses and investment plans. In practice, DSOs embed assumptions about peak demand reduction and local generation into load forecasts, effectively integrating flexibility into overall consumption growth projections rather than listing standalone projects. The eventual utilization of flexibility is addressed in the DNDPs through strategic planning and practical studies aimed at adopting flexibility measures.

To further incentivise innovation, the Finnish Energy Authority also incentives DSOs (and the TSO) to research new potential alternatives to system expansion by offering the possibility to include a cost equalling 1% of their yearly network business related turnover to a specific innovation. This must address one of the following categories: smart metering, demand flexibility, flexibility solutions,

---

[28] DR4EU. 2022. Link : Demand Response in Finland.

batteries, storages or electric vehicles. This regulatory mechanism encourages and facilitates experimentation to explore new alternatives to system expansion.

Furthermore, Finland is already testing DSO-TSO coordination on flexibility utilisation in practice. Fingrid (the TSO) and Helen Electricity Network (a large DSO) launched the pilot project 'FinFlex', which is a joint congestion management market[29]. This market allows the TSO and DSO to buy flexibility services from distributed energy resources to relieve grid constraints in real time. Through FinFlex, flexibility (e.g. load reductions) are used to defer or avoid network upgrades in both the transmission and distribution system. The project runs until 2027, and its success could be a first step towards a nationwide flexibility market, further embedding flexibility into formal network planning and operations in Finland.

Evaluation: Finland's approach to flexibility integration in DNDPs is progressive and well-anchored in legislation. The legal obligation ensures that DSOs consider flexibility as a standard part of their planning process, while inclusion of innovation funding and pilot projects further supports the development of new solutions.

The implementation of flexibility does still remain at an early stage. While DNDPs reference flexibility measures, they often lack detailed forecasts or quantifiable targets. At the same time the operational use of flexibility for congestion management is still limited. There is also variation in how DSOs interpret and apply the flexibility requirement, which affects comparability and effectiveness. Overall, Finland's framework for flexibility integration provides a strong foundation.

[29] Fingrid. N.d.. Link: TSO-DSO congestion management market.

4. Design features for appropriate network tariff regimes and regulatory incentives

As the EU moves towards a more decentralized electrical system with more renewable generation and higher power demand, appropriate tariff designs and regulatory measures are essential for guaranteeing appropriate and timely distribution network expansion. The network tariff regime faces the challenge to encourage grid-friendly behaviour from grid users, while enabling DSOs to recover their costs, and support intelligent electrical network initiatives.EU Policy Action is already in place and being further developed, as summarized in **Infobox 3**.

Infobox 3

BOX 3: EU Policy Action on network tariff regimes and regulatory incentives

Several points are emphasized in EU regulation, which are here briefly summarized.

Regulation (EU) 2019/943, Article 18:

- **Cost-reflectiveness**: Tariffs shall reflect actual incurred costs. They should be based on the costs of a structurally comparable and efficient network operator.
- **Transparency and non-discrimination:** Tariffs shall be transparent and applied in a non-discriminatory way. They shall not include unrelated policy costs or discriminate against specific technologies (e.g. storage, self-generation, or demand response).
- **Support for system efficiency:** Tariffs should promote long-term system efficiency. They shall provide price signals that encourage efficient behaviour by consumers and producers.
- **Technology neutrality:** Network charges shall not positively or negatively discriminate between: distribution vs. transmission-connected generation, storage vs. conventional supply, active customers (self-generator, flexible consumers) vs. passive ones.
- **Structure of tariffs:** Tariffs may include capacity-based elements (e.g. based on connection size). Tariffs can vary by user consumption/generation profile.
- **Time- and locational signals:** Where smart meters are deployed, time-differentiated tariffs should be considered. Tariffs may include locational elements, accounting for losses, congestion, and infrastructure costs.
- **Incentivizing innovation:** Regulatory regimes shall also provide incentives to grid operators to: improve energy efficiency, enable market integration and flexibility, invest in digitalisation and innovation,

Regulation (EU) 2024/1747, Recital 23:

- Tariffs should account for both OPEX and CAPEX of system operators, or an efficient combination of both.
- The principle of cost-reflectiveness should not prevent efficient cost redistribution through time- or locationally differentiated charges.
- Regulatory authorities should support anticipatory investments to accelerate grid development in line with the rapid expansion of renewable energy generation

Grid Action Plan:

- In Action 4, anticipatory investments are addressed, and a roadmap is given for the development of a guideline for conditions under which anticipatory investments should be approved.

- In Action 8, emphasis is given on developing best practices for tariff design. Points mentioned are the consideration of CAPEX and OPEX, the need for regular review of tariff regimes, cost-reflectiveness of withdrawal, injection and connection charges. Following Action 8, ACER focused on recommendation of best practices in its current tariff report (published March 2025).

In this context, the target for the topic area "network tariff regimes and regulatory incentives" is to pinpoint the essential elements of network tariff regimes and regulatory incentives that support the establishment of a sufficient and timely distribution network expansion, in a forward-looking way.

There are many measures and approaches to this across the EU. Cost-reflective connection fees and injection tariffs, as well as storage facility treatment that encourages effective and grid-friendly use, are emerging factors for new grid users, taking into account the burden on consumers as grid investment increases.

For the data collection within the EU-27, we explore the topic area along two **subtopics**, namely:

1. Network tariff regimes

2. Regulatory incentives for DSOs

To summarize the breakdown of the topic area, **Table 6** shows the respective subtopics and design categories.

Table 6: Subtopics and design categories for topic area 2

2. Topic area: Appropriate Tariff Regimes and Regulatory Incentives	
Subtopic 1:	**Network tariff regimes**
Design category 1	Charges for Withdrawal and for Injection
Design category 2	Connection Charges
Design category 3	Variable Network Charges
Design category 4	Treatment of Storage Facilities
Design category 5	Responsible party for tariff methodology
Design category 6	Cost Recovery at Distribution Level
Subtopic 2:	**Regulatory incentives for DSOs**
Design category 1	Regulatory regime
Design category 2	Regulatory approval of DSO investment requests and operational expenditures
Design category 3	Regulatory approval of cost recovery

The first subtopic focuses on the structure and components of network tariffs, which are key to setting incentives for grid users. The second one then examines the incentives for the DSOs in the form of the regulatory regime and the approval practices for grid investments and related costs.

As in the previous chapter on network planning, the same three institutional levels characterise the design of the subtopics: EU level requirements, national level requirements, and stakeholder-specific implementation. Especially in this topic area, there are many MS-specific design configurations that attempt to work towards future-proofing distribution grids in line with the Grids Action Plan highlighting the need for guiding principles for anticipatory investments, the promotion of smart grids and network efficiency technologies. We examine how this can be supported through tariff design, focusing on the consideration of operational expenditures (OPEX) in addition to capital expenditures (CAPEX) and benefit sharing.

The need for guidance and for revised incentives for grid users and DSOs is recognisable on the second institutional level, the national regulation. For instance, regarding anticipatory investments, a recent report by ACER and CEER[30] identifies a lacking definition in the national regulatory frameworks. So far, if anticipatory investments are included, these are treated as other investments in terms of incentives and penalties. Due to the high risk of anticipatory investments, these are often not approved.

On the third level, uncertainty and intransparency over changing national and supra-national requirements reinforces the risks for the DSOs and the grid users and disincentives innovative actions. We therefore also consider stakeholder communication as a relevant design aspect.

In the following, the design categories for the two subtopics and different institutional levels are introduced and contextualised, followed by the current state of the analysis and the proposed selection of topic-MS combinations for deep dives.

4.1. Design categories

DESIGN CATEGORIES FOR 1. Network tariff regimes

The first subtopic comprises six design categories. The first four cover the different charges, their design (e.g. calculation basis, variability) and their exemptions (especially for storage facilities). The fifth design category clarifies which stakeholder is responsible of defining the methodology for these charges. The last category builds the bridge to the second subtopic by explaining how these network tariff regimes contribute to the cost recovery of DSOs.

1. **Charges for Withdrawal and for Injection:** When designing withdrawal or injection charges, different design aspects need to be considered. First, the calculation basis, such as energy-based, power-based, or fixed/lump sum charges. Energy-based charges are calculated according to the volume withdrawn or injected over a period, typically measured in kilowatt-hours (kWh). Power-based charges are determined by the maximum capacity or peak power used or injected, typically measured in kilowatts (kW), regardless of the duration. Fixed or lump sum charges are set as a fixed amount, independent of the energy volume or power, often applied per connection point or user, usually as an annual or monthly fee. Other aspects include the variability of charges (e.g. depending on the voltage, location, time, or remaining uniform across all users) and exemptions for certain users.

2. **Connection Charges:** Often new grid users need to pay a connection charge for being connected to the grid. The charge can be based on the direct costs for establishing the physical connection, known as shallow connection charges. Shallow connection charges typically cover only the costs of assets like lines, transformers, or switchgear directly linking the user to the grid. Alternatively, the charge can also include the indirect cost of reinforcing or upgrading the broader grid to accommodate the new connection, known as deep charges. Deep connection charges go beyond the immediate connection and account for the additional upstream grid investments needed due to the new user. Connection charges contribute to

[30] ACER, CEER (2024): Position on anticipatory investments, self-published, available at: (last view: 14/01/2025)

cost recovery but can also provide locational signals to steer grid connection requests (see Topic 3).

3. **Variable Network Charges:** For the increasingly discussed variable network charges, a main design aspect is their differentiation over time. This includes seasonal, weekday, time-of-day, and other period-based variations. Seasonal variation means that network charges change depending on the time of year. Weekday or day-type variation means that charges can differ between weekdays and weekends or between working days and public holidays, reflecting typical differences in demand. Time-of-day variation refers to charges that differ between periods within a day, such as peak hours with higher charges and off-peak hours with lower charges, to reflect grid usage patterns.

4. **Treatment of Storage Facilities:** Since storage facilities withdraw and inject electricity to the grid, both kind of charges may apply to them. The EU Clean Energy Package, specifically Article 18(4) of the Electricity Regulation (EU) 2019/943, addresses this issue by banning so-called dual charging for storage facilities. Withdrawal can be measured on a gross or net basis. Gross withdrawal refers to the total amount of electricity taken from the grid, regardless of how much in reinjected. Net withdrawal, by contrast, refers to the difference between electricity withdrawn and reinjected, meaning only the portion actually consumed or lost is counted. It is the use of net withdrawal that can effectively prevent dual charging, as it ensures storage facilities are not charged twice for the same energy flow. Exemptions of withdrawal and injection charges for storage facilities are clarified in this design category.

5. **Responsible party for tariff methodology:** In most MS, the NRA determines the tariff methodology. But differences among the MS may apply and also processes for involvement of different stakeholders can differ.

6. **Cost Recovery at Distribution Level:** Cost recovery mechanisms ensure financial sustainability for DSOs. One key design aspect in the context is the applied cost recovery model for setting the tariffs. The average cost model recovers costs based on the historical or current average costs of the network. The forward-looking cost model is based on the expected or projected costs of the network, including planned investments. The incremental cost model focuses on the additional or marginal costs that arise from serving new demand or adding new users to the system. Another key design aspect is the weight of the different tariffs, and their tariff components used to recover costs. For example, it considers whether costs are mainly recovered through the energy-based, power-based share or the fixed share of the withdrawal or injection tariff.

DESIGN CATEGORIES FOR 2. Regulatory incentives for DSOs

While the first design category outlines the fundamental distinction of the regulatory regime, the following three design categories clarify which kind of costs the DSOs is allowed to recover and how, as well as which incentives exist for the DSOs.

1. **Regulatory regime:** A fundamental distinction for the regulatory regime of DSOs is whether it is cost- or incentive-based and how long the regulation period is set. In contrast to the cost-based regulation, the incentive-based regulation promotes the efficiency of the DSOs costs (or at least certain cost components). Most of the following design categories are relevant for incentive-based regulation.

2. **Regulatory approval of DSO investment requests and operational expenditures:** This design category clarifies the cost components of the regulatory asset base (e.g. based on intangible and fixed assets, book values). The regulatory asset base (RAB) refers to the value of the assets that a regulated entity, such as a DSO, is allowed to earn a return on through tariffs. It typically includes the value of infrastructure components like cables, transformers, and substations, and in some cases also intangible assets, depending on the regulatory framework. The design category also addresses the extent to which anticipatory investments are considered. The full conditionalities for anticipatory investments are outside of the scope, but the general treatment and the identification of best practices is covered. Further, the costs of innovative grid measures (e.g. digitalization, smart grids solutions, demand response) are more driven by OPEX, consequently not only the investment approval but also the included OPEX are addressed in the assessment. In this context, the design category

clarifies the investment types considered and to what extent they can be adjusted during the regulation period.

3. **Regulatory approval of cost recovery:** This design category clarifies the role of the NRA for the cost approval and which kind of efficiency benchmark is applied in the case of an incentive-based regulation.

4.2. Analysis

1. NETWORK TARIFF REGIMES

The majority of MS applies a **combined form of withdrawal charges** based on an energy-based component and a power-based or lump sum component. In most MS, the energy-based component has the highest weight of the withdrawal charges. In four MS, the power-based component shows the highest weight (AU, GR, PT, ES) and in one MS the lump sum component has the highest weight (SE). Power-based components are mostly used for cost recovery of CAPEX and OPEX. The costs for distribution losses, system services, or metering are recovered largely through energy-based and lump sum charges. Two countries have only energy-based withdrawal charges (CY, RO) or certain grid users can choose between only energy-based or mixed charges (CZ).

In most MS, the withdrawal charges – and their components - vary depending on the voltage level or depending on the consumer type (e.g. household, business, industry, agriculture). Only one MS, AT, applies variation by location, where the variation is based on different network areas, in which several DSOs can operate. In other MS, variation by location is only done indirectly when differentiated based on DSO areas (BE (Wallonia, Flanders), CZ, DK, EE, FI, DE, GR, LT, LV, NL, PL, RO, SE).

Different kinds of **exemptions** for withdrawal charges exist. Some MS (e.g. EE, FI, DE) apply only energy-based charges as a simplified network charge (sometimes combined with a lump sum) for **low voltage grid users**. In some MS, one practical reason for this arrangement is that smart meter infrastructure is missing as a prerequisite for charging based on the power level. A few MS (e.g. SE) use fuse sizes to enforce the contracted power thresholds. Furthermore, exemptions exist for **sectoral coupling technologies** (e.g. only energy-based charges for public charging points in IT, discounts for publicly accessible EV charging infrastructure in SI, ES, and SE). Additionally in some MS, special tariffs or discounts are applied to vulnerable customers (e.g. BE, IT, PT), industrial customers (DE, SK) or agricultural users (LT).

More than one-third of the EU-27 MS (AT, BE, DK, EE, FI, FR, LV, MT, NL, SK, SE) apply **injection charges**, mostly for reasons of cost-reflectivity. In a similar fashion to withdrawal charges, they are often a mixture of energy-, power- and lump sum-based components and tend to vary per voltage level. Out of the MS applying injection charges on distribution level, only Estonia does not also apply them on transmission level to promote investment in transmission-connected RES. The Netherlands only apply marginal transmission and distribution injection charges to avoid distortions. Three MS only apply them at transmission level (BG, IE, RO). An overview of MS applying injection charges on transmission (G- and non-G-charges[31]) and distribution level is given in **Table 7**.

Creating distortions in competition, risk of cost for producers, or incentivizing penetration of distributed generation are common reasons not to apply them on distribution level. Wallonia, Belgium, addresses the issue of market distortion by setting distribution-level injection charges so that the costs faced by producers reflect a weighted average of the injection charges applied in other regions of the country, at the transmission level, and in neighbouring countries. Two of the MS (DE, SE) apply **negative injection charges**, which are paid back to the producers. One reason for this arrangement is to account for the lower usage of higher voltage levels due to decentralized producers. However, in Germany, this arrangement is phasing out and in Sweden, the negative

[31] G-charges are transmission level injection charges that include cost recovery for costs for building, upgrading and maintaining infrastructure (CAPEX & OPEX), but do not include connection charges, charges for ancillary services, or charges for system losses. An upper limit for G-charges is set for each MS within Commission Regulation (EU) 838/2010.

charge is counterbalanced with a regular positive charge. Additionally, in Sweden, injection charges also have a locational differentiation by including a locational price structure as well as the distance of the generation site to the transmission grid connection point.

Table 7: Overview on application of injection charges on transmission (G- and non-G-charges) and distribution level within the EU-27 MS.[32]

Member State	Transmission charges for injection	Distribution charges for injection
AT	X	X, recovery of costs for grid losses, system services, and metering, administrative/management
BE	X	X (Flanders, Wallonia), recovery of costs for building, upgrading and maintaining infrastructure (Flanders), system services (Wallonia), and metering, administrative/management (Wallonia)
BG	X	
DK	X, G-charges	X, recovery of OPEX, charge includes grid losses, system services, metering, administrative costs; CAPEX recovered through connection charges
EE		X, cost recovery not aiming at specific cost category
FI	X, G-charges	X, capped by national law, no further information available
FR	X	X, only marginal, recovery of costs for metering, administrative/management
IE	X, G-charges	
LV	X, G-charges	X, cost recovery not aiming at specific cost category, ceiling set for G-charges according to transmission level
MT	(no transmission network)	X, recovery of costs for metering, administrative/management
NL	X, only marginal	X, only marginal, recovery of costs for metering, administrative/management
RO	X, G-charges	
SK	X, G-charges	X, cost recovery for costs for building, upgrading and maintaining infrastructure (CAPEX & OPEX)
SE	X, G-charges	X, cost recovery for costs for building, upgrading and maintaining infrastructure, grid losses, and metering, administrative/management

[32] Source: compiled from Acer Annex 2025

Different options for the power-based element (injection and withdrawal) are used throughout the MS, which may vary depending on the voltage level or consumer type: 17 MS use a contracted capacity-based element (BE, HR, CZ, EE, FR, GR, HU, IE, IT, LT, NL, PL, PT, SK, SI, ES, SE), with monthly (e.g. BE, CZ, SI), annual (e.g. FR, HU, IE, NL, ES, SE) or completely flexible (e.g. EE, PT) subscription periods. Some of these elements vary by time of day (e.g. ES, GR). In most MS power-based elements based on the measured peak load of consumers exist. The peak load is in most MS defined as the monthly or annual peak, but also other specifications exist such as the individual peak during peak hours (HR), the average of the top x hours per year or month (DK, SI, SE), or the power exceeding a contracted power limit (ES).

Deep **connection charges** are applied in more than half of the EU-27 MS. In all but three MS (BG, MT, NL), connection charges vary by voltage level. There is a variation based on location in approximately half of the MS. This variation can be based e.g. on different network areas (AT), on the distance from the existing network (CY), or regional areas (CZ, BE (Wallonia)). Some variation also stems from case-by-case calculation of the connection charges (SE, FI).

More than two-thirds of MS apply **time-of-use tariffs (ToU) for withdrawal charges** (not for injection charges, only some DSOs in SE apply those). Seven countries do not apply them (BG, CY, HU, IT, LV, LU, RO), 3 MS apply them only to a limited share of network users (DE, GR, NL). It is often applied only to energy-based charges (AT, BE, DK, EE, DE, IE, LT, MT, NL, PL, SK) or energy- and power-based charges (HR, CZ, FI, FR, PT, SI, ES, SE). In Greece, it is applied to a power-based charge. A **static ToU** is the most frequent form applied. The pre-defined tariff time periods vary usually within a day (e.g. peak and off-peak hours), by weekdays, and/or by season.

For the **variation within a day** a variety of concepts is seen throughout the MS. Most MS (17) have two to three tiers; some show a finer granularity (e.g. PT). Also, the number of periods with consecutive hours in one tier varies. In Spain, for example, the number of periods per day depend on the kind of grid user and their withdrawal charge component. I.e., the power-based ToU for households consists of two periods, the energy-based one of three and the energy- and power-based ToU for non-households of six periods. In other MS, the number of periods per day is as low as two (e.g. day/night).

14 MS distinguish between **seasons**. Most of them distinguish between two seasons (e.g. AT, DK, EE, FI, FR, PL, PT, SI, SE). Spain and Germany distinguish between three or four seasons; Greece has monthly variations. In Estonia, optional peak tariffs only apply during winter months. As an **exemption** to the pre-defined time periods for variation, France has the option to announce peak period days a day ahead for medium voltage (MV) customers. The peak period days reflect critical days in the transmission grid.

An increasing trend exists that it becomes **mandatory to offer ToU withdrawal charges**. For instance, in Germany, ToU are introduced in a stepwise process, starting with a simpler form of ToU, from 2025. In the German case, but also in other MS, this process is conditional on the availability of smart meter infrastructure that allows for appropriated billing of ToU. Opt-out options throughout the MS are mainly given for smaller users (e.g. households) in the low voltage grid.

However, in 11 MS, **grid users can choose between variable and non-variable network charges** (BE (Flanders and Brussels), HR, CZ, FR, LV, LT, MT, PL, PT, SK, SI). In some cases, the choice of ToU is limited to consumers with specific appliances such as heat pumps or electric vehicles (e.g. CZ) or smart meters (most MS, not SI). In other MS, it is only mandatory for certain users (AT, BE (Wallonia), HR, EE, GR, NL, PL, PT, ES). This exemption applies to larger users defined by their connection rate (e.g. >20.7 kVA in PT), by their voltage level (high voltage users in PL) or other categories (user groups DG6-10 in IE).

The experience on whether users are **actually exposed** to ToU varies between the MS depending on the available smart meter infrastructure, the users' right to choose, and/or the applied exemptions. For instance, in Spain and Estonia, ToU are applied to over 90 percent of the distribution grid users; in Ireland and Portugal, to 10 to 25 percent; in Latvia and Lithuania to less than 10 percent. Highest application rates can be found in Denmark and France with over 95 percent.

In 19 MS, **storage facilities** are exposed to network charges – in most cases withdrawal charges. In some MS (AT, BE, DK, FI, FR, IE, SK, RO, SE), withdrawal and injection charges are applied, in others (CY, SI, ES), neither of these two charges are applied to storage facilities. Exemptions from certain parts of the charges are applied in several MS. In Wallonia, Belgium, exemptions from taxes and surcharges on DSO tariffs and full exemption on TSO tariffs exist. There is a reduced fixed capacity charge and energy charge for withdrawal in Poland. In other MS certain parts of the energy consumption are exempted. For example, no withdrawal charges must be paid for energy stored in Italy, Lithuania (storage facilities > 5MW), and Germany.

Exemptions exist for pumped-storage hydroelectricity (PHES) in Austria, Czechia, Germany and Portugal (e.g., no power-based component of withdrawal charges for PHES in CZ) and for small-scale storage facilities in Ireland, Lithuania, Romania and Slovakia. Regarding the latter, the exemption is linked to the installed storage capacity, to its system-friendly usage and partly refers to certain components of the tariff. Particular examples of how this is applied include:

- AT: > 1MW is exempt from charges for grid utilization and network losses for 15 years after commissioning
- IE: < 5MW exempt from transmission network charges; incremental increase for storage systems > 5MW
- LT: < 1MW exempt from all network tariffs; for > 1MW additional exemption in the case of use for network stability
- RO: < 5MW exempt from transmission network charges for injection
- SK: exemption in the case of offering ancillary services; hydroelectric power plants with capacity < 5MW are fully exempted

The treatment of facilities is a more relevant topic in some MS than in others, where no or few commercial storage facilities as pumped hydro energy storage (PHES) exist (BG, CY, FI).

With respect to **prosumers**, withdrawal charges apply in all MS, mostly including an energy- and power-based component (and lump sum). Some of the MS where injection charges apply for generation units, they are not applied for prosumers (e.g. FR, NL, partly SE). In other MS, there are exemptions from injection charges for smaller prosumers (e.g. AT, BE, DK, FI). In some MS prosumers pay for net withdrawal or net metering is applied (HR (household consumers), CY, FI, HU (prosumers with micro power plants), LU).

In 21 MS, the **NRA** is the responsible party for setting the tariff methodology. In some MS, the responsibility is shared with the DSOs, since they propose the methodology and the NRA approves it (DK, GR, IE, MT). In a few cases, the DSO is in charge with no need for approval by the NRA (FI, SE). There is no fixed frequency for amending the tariff methodology in most MS. In MS where there is, the period lies between 2-8 years. Tariff values are most commonly set annually.

In 22 MS, **the determination of tariffs for cost recovery** is based on average costs. Only in France and Portugal, the basis are **incremental costs** and in Croatia, Estonia and Sweden forward-looking costs. Regarding the incremental approach, France and Portugal apply a multiplicative adjustment of the unit charges to account for the residual cost. Regarding the **forward-looking** cost model, Croatia, Estonia account for costs that are **changing during the application of the network charges**; Starting 2027, Sweden will have a mix of all three cost models, where the average cost approach is applied to customer related charges, the forward-looking cost model is applied to the capacity component, and the incremental cost model is used for the energy-based component. Residual costs are recovered through a semi-fixed component in Sweden. In Croatia they are included in the unit prices two years later (incl. consideration of inflation), and in Estonia, the DSO can request the adjustment of network charges whenever needed.

Regarding which **components of the network tariff** account for what share of the cost recovery, the energy-based component has a higher weight than the power-based one in most MS. Only in Slovakia, Latvia, Portugal, the Netherlands, Italy, Slovenia, and Spain, the opposite is the case, i.e. the power-based component covers more costs than the energy-based one. Comparing distribution cost recovery through withdrawal vs. injection charges, almost all MS show a substantial share of equal to or more than 95 percent cost recovery through withdrawal charges. However, in Sweden, cost recovery through injection charges is at approximately 16 percent on a regional grid level.

2. REGULATORY INCENTIVES FOR DSOS

An **incentive regulation** is the most common regulatory regime in the EU-27. 14 MS implement the incentive regulation based on revenue caps; four MS do this based on price caps. Ireland applies an incentive regulation with a cap and collar system, which is a revenue-based method. A cost regulation is only used in three MS, either with a rate of return (BG, EE) or a cost-plus regulation (HR). Further, five MS combine a cost regulation with components from incentive regulation (BE, DK, IT, MT, PT).

The **regulatory period** varies between the MS. Most of the MS have a regulation period of four to five years. The shortest regulation period of one year is used by Croatia, Greece, Poland and Slovenia, whereas Spain has the longest with six years. Belgium's regulatory framework varies between Flanders and Brussels Capital Region, so that the DSO in Brussels follows a five-years regulatory period and the ones in Flanders a four-years period. For DE a change in regulatory period from five years to three years is currently discussed (from 2033).[33]

The most common approach to **determine the allowed revenue** is to calculate the regulated asset base (RAB) as one component and apply the weighted average cost of capital (WACC). Which **kind of assets are considered in the RAB** varies between the MS. While fixed assets are a common element, working capital and assets under constructions are mainly included in Belgium, Denmark, Czechia, Germany, Greece, Ireland, Italy, and Poland.

Besides the assets that are directly related to physical infrastructure, there is also consideration of intangible assets, for example in Austria, Latvia, the Netherlands and Poland. Intangible assets in the context of the energy transition refer broadly to investments in innovation and digitalization (without physical substance), including in particular « *software, R&D, data, management efficiency, branding* ».[34]

Some MS include **intangible assets** in the regulated asset base and exclude only specific assets (e.g. software licenses in EE). For the grid context, there is no general distinction available to the best of our knowledge which assets belong to this category and which not. For the purpose of our study, we thus refer to intangible assets as investments aiming to improve the usage of physical infrastructure. Software is the most frequently mentioned item when comparing the MS.

Regarding **based on which method** the asset costs are determined, most MS apply a combination of historical and re-evaluated values. Only in some MS, the values are mainly based on historic values (AT, CZ, CY, EE) or the last re-evaluation of the values lies in a more distant past (e.g. in GR in 2004). In some MS, the historic values are adjusted based on an index that accounts for inflation or other developments (e.g. IE, LU, NL). Six MS apply mainly the re-evaluation approach (IT, LV, PL, RO, SE, SK).

Some MS **distinguish between the kind of asset or kind of company for the evaluation approach**. For instance, in Italy, the historical costs are applied for bigger companies and standard unit cost (sectoral average) for smaller companies. In Denmark, the RAB is divided into two parts with a forward-looking approach for the assets invested in from January 2018 onwards and the historical asset base before that moment in time.

The **role of anticipatory investments** in the regulatory cost approval is ambiguous. Reasons are a missing definition and unclear link between the investments identified in the DNDPs and their cost approval. Positively framed, the involvement of the NRAs in the DNDP process has the potential to

---

[33] Draft Decision relating to the proceedings for the determination of a regulatory framework and the methodology for incentive regulation for electricity distribution system operators ("RAMEN Strom"), BNetzA, Ref. GBK-25-01-1#1, https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/GBK-GZ/2025/GBK-25-01-1%231_RAMEN_Strom/Downloads/Beschlussentwurf_RAMEN_Strom_DL_BF_EN.pdf?__blob=publicationFile&v=3

[34] IEA (2018). Commentary: IEA steps up its work on energy innovation as money flows into new energy tech companies. Online at https://www.iea.org/commentaries/iea-steps-up-its-work-on-energy-innovation-as-money-flows-into-new-energy-tech-companies

lay the basis for cost approval. The scrutiny of both approval processes (DNDP and RAB) may differ depending on the level of information for assessment in each process.

The majority of MS only allow for efficient investments that are based on connection requests or refurbishment needs of existing infrastructure. BG, for example, approves investments based on current needs and projects and Croatia uses a historic cost approach. However, for Sweden anticipatory investments are not a defined term as well, but it is common to invest with a reasonable margin based on prognosis for expansion and development. Other MS mention a certain link between RAB and DNDP (e.g. PT, ES, PL, FI, RO, SI and LT). In Spain, DSOs with more than 100,000 consumers develop a 5-year investment plan. DSOs with fewer consumers might prepare such plans based on request. In Romania, the investment plan for the entire regulation period is verified in terms of necessity, opportunity, efficiency, and cost of investments. The regulatory authority removes the investments that prove to be inefficient ex-post from the RAB.

Other MS consider **future developments for investment approval**. In Denmark, DSOs may propose forward-looking investments (e.g., larger cables anticipating future EV load). So far, the DSOs bear the risk of "anticipatory" expansion, and they must justify expansions with real near-term demand or face potential shortfalls in revenue. However, there is a new regulation discussed, allowing for "green" investments, to qualify for additional revenue cap supplements. Further, in Latvia tariffs are based on justified historical costs and forecasts for any other future costs. In Hungary, higher capacities for new investments can be planned in case of anticipation of higher demand and will be approved by the regulatory authority.

Whether an anticipatory investment is accepted or not is in most MS subject to an **individual cost assessment**. It is non-transparent whether one kind of anticipatory investment is more likely to be accepted than another. Such a pattern would provide the bottom-up basis for definition of anticipatory investments. While most NRAs state that anticipatory investments may be accepted as long as they are reasonable, this lacking pattern and missing definitions imply risks for the DSOs.

In the EU-27 MS, similar methodological components (e.g. CAPM[35] and WACC) are applied to calculate the return on revenue for the DSOs. However, **to which extent the capital (CAPEX) and operational expenditures (OPEX)** are considered and how often they are adjusted within a regulatory period varies between the MS. The traditional approach of calculating the return based on the CAPEX does not incite OPEX-driven smart grid investments. Two alternative approaches exist. On the one hand, some MS (e.g. PT, SE) follow a more comprehensive approach and refer to the total expenditure (**TOTEX**). Certain cost components might be excluded from the calculation of a TOTEX regulation to avoid inefficiencies. For instance, Sweden deducts grid components without active customers from the capital base. On the other hand, the **agile investment framework** of Ireland allows the DSO to **reallocate allowances between OPEX and CAPEX**.

For the **approval of cost recovery**, regulatory authorities use different instruments, such as a yardstick benchmarking (efficiency comparison) to simulate a competition between DSOs or a quality element to avoid cost reduction at the expense of network quality. 14 MS apply a yardstick comparison (AT, BG, CZ, DK, EE, FI, DE, HU, NL, PT, RO, SK, SI, ES). The Data Envelopment Analysis (DEA) is one of the main benchmarking methods, followed by the Stochastic Frontier Analysis (SFA). A quality element is applied in 13 MS (BE, BG, CZ, FI, DE, HU, LT, PL, RO, SI, ES, PT, SK), mainly using the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI), which are indicators for the power outages. Other MS also include the quality of service, such as Portugal and Slovakia.

For the **treatment of costs related to flexibility**, such as smart grid systems or demand responds mechanisms, some MS provide certain incentives. Portugal and Luxembourg include in their quality incentives the quality of service related to smart grids (PT). Finland also includes incentives for innovation, while Ireland includes incentives associated with continuity of supply, estimated restoration time accuracy, customer satisfaction, smart metering, stakeholder engagement, worst-served customer, timely issuing of connection offers, visibility, flexibility, DSO/TSO coordination, and independent role of the DSO. In addition, Ireland provides mechanisms for uncertainty, flexibility,

[35] Capital asset pricing model.

innovation and R&D. Denmark includes an index for automatic indicators based on the number of smart meters and substations installed by a DSO.

The regulatory period applied can lead to time delays in cost recoveries that appear during the set period. Therefore, most of the MS (19 MS) address this issue by applying methods for **adjustments during the regulatory period**. Adjustments for CAPEX and OPEX are considered by Austria, Belgium, Denmark, Hungary, Lithuania and Romania. Austria, for example, adjusts OPEX based on price index, general productivity offset and efficiency factor. The latter is also applied for the adjustment of CAPEX as well as a mark-up on WACC. An adjustment of CAPEX but not of OPEX is applied in Germany and Spain. Slovakia only allows for the request of RAB adjustments during the five-year regulatory period in the event of significant changes in economic parameters.

Other adjustment methods are used by Bulgaria, Cyprus, Ireland and Italy. While Bulgaria includes changes based on fulfilment of investment program, Cyprus only allows for CAPEX adjustments if they are lower than approved. Ireland implemented specific mechanisms for uncertainty, flexibility, innovation and R&D. Italy adjusts annually based on performance incentives such as OPEX efficiency improvement, quality of supply and network resilience by rewards and penalties.

Additionally, in the Netherlands, circumstances for immediate corrections exists:

- (a) by court ruling,
- (b) if it turns out that the decision was based on incomplete or incorrect data,
- (c) if deviations between estimates and realizations are disproportional, or
- (d) if the revenue is based on services that a network operator no longer provides.

Furthermore, Finland changes its regulation methods every regulatory period. Bigger changes in the regulatory frameworks are discussed in Italy, Germany and Poland.

4.3. Selected practices for deep dives

The rising share of RES in the energy system as well as the increasing electrification and availability of sector coupling technologies on distribution level (e.g. electric vehicles, heat pumps) increases the requirements and will lead to substantial changes in distribution grids in the coming years. We therefore put the focus on aspects for network tariff regimes and regulatory incentives that **enable flexibility in responding to future changes**. Five priority themes can be derived from the design categories and related to the design features described above. In the following, an overview of the priority themes is provided and possible MS selections for deep dive analyses are described.

1.MEANS FOR INNOVATIVE AND COST-REFLECTIVE NETWORK TARIFF REGIMES

More cost-reflective network charges that do not exclusively recover the network costs based on the used energy and/or involve time dependent variations reflecting the grid situation can spur investments in sectoral coupling technologies and their grid-friendly operation. This, in turn, can help mitigating distribution grid costs (CAPEX/OPEX, grid losses, system services). At the same time, ensuring cost recovery with an innovative but complex network tariff regime and enforcing them may present a challenge for DSOs. The following presents the deep dives of the selected practices and gives a brief rationale for the choice.

Design of ToU withdrawal charges in Slovenia and Spain

Looking at current practices in the MS, a combination of energy- and power-based ToU withdrawal charges is seen as the best option for cost-reflective tariff design and grid-friendly behaviour. We therefore chose Slovenia and Spain as deep dive MS, both having mandatory power- and energy based ToU withdrawal charges.

a) Spain

Context: In 2021, Spain implemented an advanced and granular ToU tariff system, enabled by a fully completed smart meter rollout (100% in 2023[36]). The country has five large DSOs (each serving over 100,000 customers) and more than 300 smaller ones. Spain has a high share of RES, with 57% of electricity generation in 2023[37] being from wind (44%) and PV sources (32%). This poses both opportunities and challenges in terms of integrating fluctuating supply. To manage this, ToU network tariffs were introduced in 2021[38], creating clear incentives to shift consumption away from peak times and promote system efficiency.

Content: Spain's tariff design combines both mandatory power-based and energy-based ToU charges, with a stronger emphasis on the power component. Consumers are assigned to six tariff periods within the voltage levels NT0-NT4 (i.e., NT0 < 15kW for households, NT0 > 15kW for larger consumers on the low voltage level, NT1-NT4 for larger users on the higher voltage levels). For non-household users, the same six ToU periods apply to both power- and energy-based charges. For households, there are two periods for energy but three for power, reflecting a simplified structure for transparency and simplicity. Periods vary by season, month and day (see **Figure 1** and **Figure 2**). Spatial differentiation is made between the peninsula and the islands. Power-based charges are based on contracted capacity for each ToU period and include a surcharge for excess withdrawal. Contracted capacity can be adjusted by the user once every 12 months free of charge. A fee applies for more frequent adjustments. Power-based charges are intended to cover the fixed costs of infrastructure, while energy-based charges primarily account for losses and are therefore higher in lower voltage levels due to cost cascading. ToU periods and locational split are based on demand curves analyses[39]. Periods vary between 5 systems: peninsula, Baleares, Canary Islands, Ceuta, and Melilla.

	energy-based		power-based	
	Type of day		Type of day	
Time period	Mon-Fri all year	Sat, Sun, holidays, Jan 6 all year	Mon-Fri all year	Sat, Sun, holidays, Jan 6 all year
P1	10:00-14:00 18:00-22:00		8:00-0:00	
P2	8:00-10:00 14:00-18:00 22:00-0:00			
P3	0:00-8:00	all hours of the day	0:00-8:00	all hours of the day

Figure 1: Time blocks for ToU tariffs applied for households in Spain (peninsula)

[36] JRC 2023 - https://data.europa.eu/doi/10.2760/237911

[37] Eurostat - https://ec.europa.eu/eurostat/databrowser/product/page/nrg_ind_ured__custom_14947349

[38] BOE Circular 3/2020 - https://www.boe.es/buscar/pdf/2020/BOE-A-2020-1066-consolidado.pdf

[39] CNMC CIR/DE/002/19 - https://www.cnmc.es/sites/default/files/2808025_51.pdf

	energy- and power-based				
	Type of day				
	Mon-Fri				Sat, Sun, holidays, Jan 6 all year
Time period	Jan, Jul, Aug, Sep	Feb, Dec	Jun, Oct, Nov	Mar, Apr, May	
P1	9:00-14:00 18:00-22:00				
P2	8:00-9:00 14:00-18:00 22:00-0:00	9:00-14:00 18:00-22:00			
P3		8:00-9:00 14:00-18:00 22:00-0:00	9:00-14:00 18:00-22:00		
P4			8:00-9:00 14:00-18:00 22:00-0:00	9:00-14:00 18:00-22:00	
P5				8:00-9:00 14:00-18:00 22:00-0:00	
P6	0:00-8:00	0:00-8:00	0:00-8:00	0:00-8:00	all hours of the day

Figure 2: Time blocks for ToU tariffs applied for non-households in Spain (peninsula)

Evaluation: The Spanish tariff system is cost-reflective, aligning contracted and actual demand and encouraging electrification without requiring an increase in contracted capacity. This approach helps avoid the need for costly grid reinforcements and supports efficient grid use, particularly as users adopt flexible technologies such as EVs and heat pumps. Power-based charges are applied across multiple ToU periods, with the charges being adapted to consumer groups and voltage levels. Excess power penalties are employed to discourage undercontracting. Energy-based charges mainly reflect losses and are more prominent in lower voltage levels. ToU periods are defined based on consumer load profiles, contributing to effective reduction of peak demand. This is particularly evident during morning periods (e.g., reduction of the average capacity for morning peak on winter working days of around 3.5 GW from 2018 to 2023), although the effects on the evening peak have been more limited[40]. This shows the challenge of appropriate and effective ToU design.

For households, a simplified structure with fewer periods enhances transparency and simplicity, while retaining key incentives. However, with increasing automation for flexible technologies (e.g., EVs, heat pumps), this simplification may become less relevant, and expanding the number of ToU periods for households with flexible technologies could improve system responsiveness. The tariff design is largely technology-neutral, encourages demand-side participation, and ensures stable revenues through power charges. However, fairness may be limited for less informed passive users, as contracted power levels must be actively managed by the consumer. Spain’s model could be adapted by other MS but depends on widespread smart metering. For MS with significant regional differences in terms of demand and generation structure in distribution grids, the underlying locational differentiation may not be sufficient to meet objectives regarding cost-reflectiveness and system efficiency.

b) Slovenia

Context: In Slovenia, five DSOs operate under a leasing agreement with the TSO. The Slovenian distribution network, which was not designed to accommodate high shares of RES or widespread electrification, is experiencing congestion. As of 2024, approximately 25% of applications for individual self-consumption were rejected due to local grid constraints, with many nodes operating close to their thermal limits. In response to these challenges, a new tariff methodology was introduced in October 2024[41]. This initiative was supported by a high level of smart meter penetration, which rose from 58% in 2018[42] to 90% in 2023[43]. Moreover, Slovenia has established

[40] ACER 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications/2025-ACER-Electricity-Network-Tariff-Practices.pdf

[41] Official Gazette of the Republic of Slovenia, Nos. 46/18, 47/18 – amended, 86/18, 76/19, 78/19 – amended, 85/20, 145/21, 172/21 – ZOEE, 123/22 and 146/22 - https://pisrs.si/pregledPredpisa?id=AKT_1050

[42] European Commission: Directorate-General for Energy - https://data.europa.eu/doi/10.2833/492070

[43] JRC 2023 - https://data.europa.eu/doi/10.2760/237911

a national data hub for the management of distribution-level information, thereby enabling advanced user interaction and monitoring[44]. Customers have access to 15-minute real-time consumption data, enhancing their ability to manage load.

Content: The updated tariff system is built around contracted capacity, determined based on the user's measured peak load during system peak periods[45]. Tariffs differentiate between power-based ToU charges (covering fixed infrastructure costs) and energy-based ToU charges (covering network losses, system services and energy transport). Charges are structured across five time blocks that vary by season, month and day (see **Figure 3**). Contracted capacity for each time block is proposed annually by the DSO, based on historical usage and capped by the customer's connection agreement. Customers are informed through their bills and the national data hub and may adjust the proposed levels in advance – free of charge. However, capacity in each time block cannot be lower than in a more critical (higher) block, which aligns user incentives with system stress levels. There also is an excessive power charge in case contracted capacity is exceeded. For the transition to the new tariff system, households and small business customers (up to 43 kW) are exempted from the excessive power charge if they do not change the agreed billing capacity proposed by the DSO. The impact of the updated tariff system on the distribution grid is assessed monthly by the NRA based on predetermined KPIs. For acceptance and transparency, a website[46] has been launched with information on the new tariff methodology.

	energy- and power-based			
	Type of day			
	working day		non-working day	
Time period	Nov-Feb	Mar-Oct	Nov-Feb	Mar-Oct
P1	7:00-14:00 16:00-20:00			
P2	6:00-7:00 14:00-16:00 20:00-22:00	7:00-14:00 16:00-20:00	7:00-14:00 16:00-20:00	
P3	0:00-6:00 22:00-24:00	6:00-7:00 14:00-16:00 20:00-22:00	6:00-7:00 14:00-16:00 20:00-22:00	7:00-14:00 16:00-20:00
P4		0:00-6:00 22:00-24:00	0:00-6:00 22:00-24:00	6:00-7:00 14:00-16:00 20:00-22:00
P5				0:00-6:00 22:00-24:00

Figure 3: Time blocks for ToU tariffs in Slovenia[47]

Evaluation: The design of Slovenia's power- and energy-based ToU tariffs allows end-users to increase electricity consumption (such as for heating and transport) without substantially increasing their network charges, by utilizing flexibility and managing their peak demand. This supports electrification and facilitates the integration of distributed RES. The updated tariff methodology substantially increased the share of power-based charges, improving cost-reflectiveness. The block-based structure, which varies across season, month and day, implicitly rewards self-sufficiency and sets strong incentives for shifting consumption to periods of lower network load. This is particularly important in a context of high PV penetration and frequent local grid congestion. A key feature is the rule that contracted capacity in less critical time blocks may not exceed that of more critical ones, reinforcing incentives to reduce peak usage while still enabling higher use during off-peak times.

This structure combines economic efficiency with fairness as the DSO proposes capacity levels based on each customer's historical peak load, and customers can freely adjust them in advance. This is supported by widespread smart metering and a national data hub with access to 15-minute real-time data. The excessive power charge helps preventing speculative undercontracting, while transitional exemptions protect small users (< 43kW) during the tariff methodology shift. Within three months

[44] Website moj elektro - https://mojelektro.si/

[45] https://www.uro.si/prenova-omre%C5%BEnine/kaj-je-omre%C5%BEnina#

[46] Website učinkovita raba omrežij - https://www.uro.si/

[47] https://www.uro.si/prenova-omre%C5%BEnine/novi-%C4%8Dasovni-bloki

of implementation, the system observed over 50MW in load relief, which corresponds to (about 2.4% of the national peak in January. Furthermore, new demand response business models emerged[48]. Contracted power charges form a stable revenue base, and excess usage is monetized through penalties. Tariffs are largely technology-neutral and incentivize flexibility, making them future-proof. Successful adaptation in other MS requires comparable advanced metering infrastructure and DSO-level visibility into grid utilisation. In larger MS with a higher number of DSOs, the Slovenian approach with nationally set tariff levels may not sufficiently reflect regional grid conditions and costs if these vary substantially.

Design of injection charges in Denmark and Sweden

Injection charges are another important element in tariff design when assessing cost-reflectiveness. Denmark applies energy- and lump sum-based injection charges, achieving approximately 5% cost-recovery through injection charges. Sweden applies power-, energy- and lump sum-based injection charges (ToU for some DSOs), reaching about 16% cost-recovery through these injection charges in the regional grid (>10kV). We chose these two member states as deep dive cases. It is important to note that differences in injection charges across countries may have distortive effects on the European electricity market. Such differences can influence investment and dispatch decisions, as producers may respond to cost differences rather than system needs or efficiency. Ideally, injection charges would be harmonised across Europe to ensure non-distortive access to the electricity market.

a) Denmark

Context: Denmark operates a decentralized distribution system with 38 DSOs with diverse ownership structures but functioning under a unified regulatory framework. The country is characterized by a high share of renewable energy, with around 79% of electricity production coming from RES[49] - 65% of which from wind and 12% from solar PV. Denmark has completed their smart meter rollout[50], which forms the basis for the Tariff Model 3.0, introduced in 2022.

Content: Denmark introduced injection charges on distribution level to enhance cost reflectivity and to accompany the phasing out of a national renewable energy subsidy scheme effective from 1 January 2023.[51] The goal was to internalize network-related costs that generators impose and to provide appropriate price signals, aligning with the principle of cost-reflectivity.

The injection tariff in Denmark consists of two components. An energy-based element (85%), which reflects the operational costs of maintaining, upgrading, and managing the infrastructure as well as grid losses, and a lump sum component (15%), covering metering, administrative, and management costs[52]. The level of charges varies by voltage level and network area, reflecting contribution to grid losses. Injection tariffs include OPEX and grid losses that feed-in to the grid entails, whereas CAPEX for grid reinforcement due to injection are recovered through connection charges[53]. When calculating

[48] ACER 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications/2025-ACER-Electricity-Network-Tariff-Practices.pdf

[49] Eurostat - https://ec.europa.eu/eurostat/databrowser/product/page/nrg_ind_ured__custom_14947349

[50] JRC 2023 - https://data.europa.eu/doi/10.2760/237911

[51] Green Power Denmark 2022 - https://greenpowerdenmark.dk/files/media/document/Anmeldelse-af-model-for-producentbetaling.pdf

[52] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

[53] In accordance with legal notes to L53/2021 (https://www.ft.dk/samling/20211/lovforslag/L53/som_fremsat.htm); connection charges have a locational component and are differentiated between three geographical zones: producer-dominated, consumer-dominated and mixed

injection tariffs, the injection-withdrawal balance of each DSO's grid area is considered[54]. Injection charges currently cover around 5% of total DSO cost recovery. Within the tariff methodology, there are no exemptions from injection charges for any type of producer or prosumer. However, limited exemptions exist through legislative acts for producers covered by earlier support schemes[55].

Evaluation: The design of the injection tariff in Denmark aligns with cost-reflectivity principles. By differentiating injection tariffs by voltage level and network area and separating OPEX recovery (via injection charges) and CAPEX recovery (via connection charges), the methodology ensures that injection tariffs are paid for operational impact of injection on the grid. Applying energy-based charges for cost recovery related to grid losses is seen as appropriate. The injection charges are largely non-discriminatory on distribution grid level, with the same injection tariff structure applying to all producers regardless of technology or scale. Limited exemptions apply that separate legacy protections from forward-looking cost allocation rules but are not part of the tariff methodology. Therefore, distortion in competition within Denmark is limited. Locational signals are given through connection charges, reinforcing efficient siting of generation and enabling a combined assessment of costs in both injection and withdrawal directions. The Danish methodology for injection charges follows the principle of transparency and simplicity and could be transferred to other MS.

b) Sweden

Context: In Sweden, 170 DSOs operate the distribution grid, ranging from large regional DSOs to small municipal utilities. The legal and methodological framework set by the NRA gives some degrees of freedom for setting withdrawal and injection tariffs, therefore implementation differs across DSOs. The country has a very high share of RES of about 88%, of which 32% come from wind and 3% from solar PV[56]. It has completed a full smart meter rollout[57], enabling advanced data-driven grid operation and tariff calculation.

Content: Injection charges in Sweden are designed for cost reflectivity and to avoid cross-subsidization between consumers and producers. It is argued that removing injection charges could unfairly shift grid costs to local consumers and would lead to a subsidy for electricity exports. Such a shift could risk public acceptance of the energy transition and reduce the attractiveness of locating industries in less populated areas[58]. The injection charges are mainly power-based and are designed to recover costs for building, upgrading, and maintaining the grid, grid losses, and metering and administrative overhead.

In one of the largest DSO areas, injection charge design differs by grid type[59]. For the local grid (up to and including 10kV), the injection charge is based on the maximum annual power produced, without temporal granularity. For the regional grid (> 10kV), the methodology introduces a locational differentiation. This differentiation is made based on the distance to the nearest transmission grid connection, multiplied by the subscribed production capacity and a locational unit price, plus a component based on voltage level. TSO injection charges are cascaded to DSO level. Producers at higher voltage levels (130kV) pay a charge for grid loss contribution, whereas generators that help reduce grid losses are paid a remuneration that is linked to the avoided energy cost of losses (energy-based). Cost allocation is performed such that injection charges are calculated first, and the

---

[54] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

[55] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

[56] Eurostat - https://ec.europa.eu/eurostat/databrowser/product/page/nrg_ind_ured__custom_14947349

[57] European Commission: Directorate-General for Energy - https://data.europa.eu/doi/10.2833/492070

[58] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

[59] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

remaining DSO costs are covered by withdrawal charges. In regional grids, injection charges currently cover approximately 16% of total DSO cost recovery[60].

Evaluation: The described approach to injection charges shows cost-reflectivity by applying a power-based and location-sensitive methodology. The distance-based component and the differentiation by voltage level links injection charges directly to physical infrastructure impact. This supports efficient investment decisions and avoids hidden subsidies that might otherwise shift the burden of network costs to local consumers. Implementing power-based charges for CAPEX cost recovery and energy-based charges for cost recovery of grid losses is seen as cost-reflective. Additionally, the design incorporates an incentive for loss reduction. This balances the cost signal of injection charges with recognition of positive contributions. The complexity of the locational cost model may pose implementation and transparency challenges in systems lacking granular network data but could be valuable for cost recovery in Member States where grid losses and infrastructure impacts vary significantly by location. However, no information was found on distortive effects on national or international level, which need to be carefully considered when designing injection charges.

Design of cost recovery in France, Croatia and Sweden

Regarding cost-recovery, incremental or forward-looking cost models better reflect the cost drivers of grid costs compared to average cost models. We focus on France as a MS with an incremental cost recovery approach, on Croatia with a forward-looking cost recovery approach and on the announced cost recovery approach in Sweden, combining all three cost recovery models.

a) Incremental cost model in France

Context: The French electricity distribution system includes 138 DSOs, but is dominated by a single operator, which manages over 95% of all connections. The country has about 30% of electricity production from RES sources, of which 34% are from wind and 16% from solar PV[61]. The smart meter rollout is at 94%[62]. This technical capacity and centralized operational structure are important enablers for the country's tariff methodology.

Content: The main objective for choosing an incremental cost model in France was to ensure cost-reflectivity, while maintaining geographically uniformised charges across the entire country[63]. Within the cost recovery model, all key cost categories – CAPEX, OPEX, grid losses, metering, system services, and DSO-specific expenses (e.g., local markets, supplier switching, R&D) are recovered exclusively through power- and energy-based withdrawal charges. Although unit prices differ by voltage level, the same pricing structure is applied across all network users within each level, and the same core methodology is used for both transmission and distribution networks.

The cost computation is grounded in a marginal cost methodology that uses detailed grid data to model the infrastructure cost across so-called "grid pockets", which are voltage-level network zones defined downstream of each transformer substation. In a first step, an econometric analysis is conducted to explain the annualised costs of each grid pocket. The analysis showed that the main cost drivers in case of the French grid are the number of users and their non-coincident peak demand[64]. This analysis allows for highly localized cost estimation. Despite this granularity, the nationally uniform tariff policy means that these pocket-level cost differences do not translate into

---

[60] ACER 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications/2025-ACER-Electricity-Network-Tariff-Practices.pdf

[61] Eurostat - https://ec.europa.eu/eurostat/databrowser/product/page/nrg_ind_ured__custom_14947349

[62] JRC 2023 - https://data.europa.eu/doi/10.2760/237911

[63] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

[64] CRE deliberation no.2021-13 of 21 January 2021 - https://www.cre.fr/fileadmin/Documents/Deliberations/import/210121_2021-13_TURPE_6_HTA-BT-en.pdf

location-specific tariffs. However, cost cascading applies from transmission to distribution level. A cost function is derived, and marginal unit prices are computed. Any remaining gap between the revenues and the allowed revenue of the DSO, for example through costs for the constitution of balancing reserves, voltage control costs, or costs for power loss compensation, is addressed via a multiplicative adjustment factor, applied to the withdrawal component at the beginning of the regulatory period.

Evaluation: The cost allocation model in France shows high cost-reflectivity at the methodological level. By using detailed grid data for marginal cost analysis, an accurate model is created of how grid users affect network costs. However, the policy of geographical uniformity prevents this granularity from being reflected in the actual tariffs, potentially reducing locational investment signals. However, this trade-off promotes social fairness and political acceptability, particularly in rural and less densely populated regions. Revenue adequacy and financial sustainability are ensured through a reconciliation mechanism, which adjusts the adjustment factor for residual cost recovery on a regular basis to align revenues with the regulated revenue cap. This shields DSOs from demand volatility or DER uptake risk.

In terms of adaptability, the French incremental cost allocation model is reliant on high availability of data for the locational marginal cost modelling. Therefore, direct transferability is limited for MS lacking infrastructure enabling high data availability.

b) Forward-looking cost model in Croatia

Context: In Croatia, a single DSO is responsible for the entire electricity distribution system. The country has a RES share of 59%, with wind making up 24% of this share and solar PV 4%.[65] The smart meter rollout in Croatia is incomplete to date, standing at 43% in the household category, but rapid progress is expected on the back of large procurement deals taken by the electricity company HEP in 2024.[66]

Content: Croatia applies a forward-looking cost model, where the primary objective is to ensure that anticipated regulatory costs and target revenues for the upcoming year (Y+1, regulatory period) are fully recovered through network tariffs applied during that same year. The methodology includes several factors for determining the tariffs[67]: recognized incurred costs, which are the actual costs acknowledged from the current year (Y), as well as any incentives that were applicable in the previous regulatory year (Y-1). The model also takes into account the revenues earned in the previous regulatory year (Y-1) and the planned costs and revenues for the current year (Y). Additionally, it evaluates estimated recognized costs and revenues for the current year (Y) (residual costs, along with an inflation adjustment) and incorporates planned costs and revenues for the subsequent regulatory years (Y+2 and Y+3). In essence, this model combines past performance with future projections to set tariff items for the next regulatory year, ensuring that all relevant financial factors are considered.

The main billing variables for the DSO include energy-based, power-based, and lump sum charges, with user differentiation based on voltage level (medium and low voltage) and user category (household, non-household, public lighting, interruptible loads). Each user group’s unit prices are computed annually using operator-submitted data and interventions in the data by the NRA. Cost cascading from higher to lower voltage level applies.

All distribution costs are recovered through withdrawal charges. Within the methodology power-based charges for producers can be applied but were set at 0 €/kW by the NRA.[68] Costs recovered

---

65 Eurostat - https://ec.europa.eu/eurostat/databrowser/product/page/nrg_ind_ured__custom_14947349

66 Balkan Green Energy - https://balkangreenenergynews.com/croatias-hep-to-buy-smart-electricity-meters-worth-eur-86-5-million/

67 HERA NN84/2022 - https://narodne-novine.nn.hr/clanci/sluzbeni/2022_07_84_1283.html

68 ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

include CAPEX, OPEX, costs for grid losses, metering, suppliers switch, R&D, EU DSO Entity. A reward/penalty scheme through tariffs for DSO grid losses is planned to be applied in 2025 for calculating tariffs in 2026.

Evaluation: Croatia's forward-looking cost allocation model incorporates forecasted costs and billing volumes of up to 3 years into tariff calculations. With annual adjustments, the DSO has a flexible framework and can react flexibly to future developments. The use of residual cost reconciliation (Y-1 into Y+1), along with inflation correction, provides a clear mechanism for addressing under- or over-recovery. This enhances financial sustainability without placing undue risk on the DSO or grid users. The model further provides the possibility for power-based charges for injection, which, in theory, makes it more cost reflective. In terms of regulatory feasibility, Croatia's model is easily adaptable to future development. Its modular structure and annual adjustment cycle allow the system to evolve with technological and policy needs. Its effectiveness depends on forecasting accuracy. No locational differentiation is made as in the French cost allocation model.

c) Combination of cost models in Sweden

Context: Additional to the high share of RES and the completed smart meter rollout, Sweden experiences a fast uptake of EV charging points and heat pumps (driven by Sweden's goal to phase out fossil fuels in heating by 2030[69]). These trends are placing increasing pressure on distribution networks and have motivated a tariff reform to support cost-reflective and forward-looking cost recovery.

Content: Starting from 1 January 2027, Sweden will implement a hybrid cost allocation model that combines elements of incremental, forward-looking and average cost approaches.[70] Each cost component is allocated based on a specific logic. The energy-based component is based on incremental cost, reflecting the marginal cost impact of network usage (short-term variable costs). The capacity-based component follows a forward-looking approach, designed to reflect anticipated future investment needs based on forecasted load growth. Customer-related charges (e.g., metering, administration) are calculated using an average cost model, ensuring broad cost coverage and simplicity. Residual costs are recovered via a fixed fee.[71] Costs are allocated in two steps. First, the DSO allocates total costs between injection and withdrawal. Then, these costs are divided into the four components (energy-based, capacity-based, customer related, fixed). Each cost component is subsequently cascaded down through the grid levels, from transmission to regional and local distribution. According to regulation, tariff levels should be reviewed at least annually. Cost types that are recovered through network charges are CAPEX, OPEX, grid losses, metering, system services (including voltage control, congestion management and payments to interruptible loads), and other DSO costs, such as suppliers switch, EU DSO Entity, local markets, R&D, and penalty/reward mechanisms.[72]

Evaluation: The upcoming hybrid cost allocation model in Sweden allows to allocate cost where it arises, while providing stable cost recovery and investment signals. The use of incremental cost allocation for the energy-based component ensures that marginal usage impacts are priced accurately, while forward-looking pricing for capacity-based charges supports anticipatory investment planning. This is particularly relevant as the grid undergoes stress from electrification trends. Customer-related costs are efficiently handled through average pricing, which ensures administrative simplicity.

---

[69] Swedenenergy 2019 - https://www.energiforetagen.se/4901de/globalassets/dokument/fardplaner/roadmap-heating-sector-summary-dhc.pdf

[70] Ei EIFS 2022:1 - https://ei.se/download/18.b0dbdc118002bc176c133ae/1650953845317/EIFS-2022-1-om-utformining-av-n%C3%A4ttariffer-f%C3%B6r-ett-effektivt-utnyttjande-av-eln%C3%A4tet.pdf

[71] Ei Website: Guidance for the design of network tariffs according to EIFS 2022:1 - https://ei.se/bransch/tariffer-nattariffer/vagledning-for-utformning-av-nattariffer-enligt-eifs-20221

[72] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

The model supports revenue adequacy through a transparent allocation of cost components and a high degree of alignment between costs and usage patterns. By separating injection and withdrawal cost allocations and applying them consistently through cascading, the model promotes non-discrimination and transparency. The hybrid design of the cost allocation model allows for flexibility in changing the detailed methodology for setting the tariff levels for individual components. Depending on the details of the tariff setting process, the model can be data-intensive, which may present implementation challenges in MS with limited metering or grid data.

2.EXEMPTIONS FOR DECARBONIZATION AND PROCESS EFFICIENCY

Exemptions for small grid users in terms of network tariff regimes (e.g. small-scale storage facilities, low voltage users) reduce the process burden and increase the attractiveness for new investments. If exemptions are designed in a cost-reflective manner and linked to a grid-friendly operation of the investments, it further supports the political targets. Ill designed exemptions can, on the other hand, lead to inefficiencies.

Variety of exemptions supporting cost-efficiency and grid friendly behaviour

The field of exemptions is quite broad amongst the EU-27 MS, which is why we suggest focusing on the exemptions in the potential MS discussed under the topic of cost-reflectivity. This also allows for a more integrated analysis on the trade-offs between cost-reflectivity, incentives for process efficiency and grid-friendly behaviour.

Context: Across the MS, exemptions to distribution network charges are used to balance cost-reflectivity with broader policy goals, such as decarbonisation, electrification, and efficient grid use. In the MS examined under the topic for means for innovative and cost-reflective network tariff regimes – Denmark, Sweden, France, Spain, Croatia, and Slovenia – exemptions are employed to support prosumer uptake, electric mobility, industrial competitiveness, and flexibility, often within otherwise cost-reflective tariff frameworks. Looking at these countries in combination with the information above allows for a more nuanced understanding of trade-offs between economic efficiency and targeted incentives for transformation.

Content: For ***prosumers***, Denmark and Sweden apply clear capacity-based exemptions. In Denmark, prosumers with ≤ 50kW of generation capacity are exempt from connection charges for feed-in, and larger low voltage prosumers only pay connection charges for feed-in for the capacity that exceeds withdrawal, allowing for cost-offsetting[73].
In one of the largest DSO areas in Sweden, small prosumers (up to 63A fuse / 43.5kW) are exempted from injection tariffs altogether. Others pay both injection and withdrawal charges if their production exceeds consumption[74].
In Croatia, a "self-supply" tariff model allows households to be charged only for net monthly withdrawal, while non-households pay for gross withdrawal, a distinction rooted in national legislation rather than the tariff methodology[75].
Net metering mechanisms – whether on a 15-minute basis in Sweden or monthly in Croatia – also act as indirect exemptions, reducing the economic burden of distributed generation and also metering complexity.

For ***consumers, electric mobility, and dispatchable loads***, the MS offer differentiated tariff options to encourage load shifting and efficiency.

[73] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

[74] ACER Annex 2025 – see previous footnote

[75] ACER Annex 2025 - see previous footnote

Spain provides EV charging stations with a choice between the general ToU charges and a specific ToU charge with a more emphasised energy-based component, allowing operators to select based on consumption and utilisation profiles[76].
Croatia's "Crni" tariff for households offers a reduced charge in exchange for direct load control through DSO for 16 hours per day (8 hours of daily delivery during off-peak times are guaranteed)[77]. The tariff model is supplementary and only applicable to dispatchable household loads. It is currently applied in two DSO areas, but planned to be expanded upon expressed interest of customers.
Some DSOs in Sweden have flexibility-based charges for charging stations, which reward controllable loads without imposing net cost burdens on the DSO[78].
Denmark addresses the issue of industrial competitiveness by applying tariff discounts for end-consumers with an annual consumption over 100GWh[79].

Standalone storage facilities also benefit from targeted exemptions.

In one of the largest DSO areas in Sweden, standalone storage facilities (non-PHES) do not pay charges for higher grid level subscription, provided some operational control is possible for the DSO[80]. This enables grid-friendly operation.
In Spain, storage is seen as possibility for increasing security of supply and is therefore incentivised by not paying withdrawal charges[81].
In Croatia, standalone storage facilities are defined as not an end-consumer (excluding own consumption), which exempts them to some extent from grid charges.

Sweden's ***local flexibility market projects***, such as Sthlmflex[82] and CoordiNet[83], treated the cost of flexibility procurement as part of the DSO's allowed revenue, which is then recovered from all grid users, further reducing entry barriers for flexible resources[84].

Evaluation: The examined exemptions reflect a strategic effort to align network tariff design with broader decarbonisation and system efficiency goals, offering incentives for prosumers, flexible consumers, and storage without fundamentally undermining revenue adequacy. When designed well, such exemptions help reduce barriers to entry for new technologies and behaviours that support grid stability and long-term cost savings.

However, a key challenge is ensuring that exemptions remain targeted and proportionate, so they do not reduce the cost-reflectivity of the underlying tariff methodology. This is particularly critical where exemptions apply to cost components meant to signal the true cost of network use, such as capacity or connection charges. If not carefully designed, they can lead to cross-subsidisation, distort price signals, and incentivize behaviour that increases long-term system costs. Blanket exemptions,

---

[76] CNMC CIR/DE/002/19 - https://www.cnmc.es/sites/default/files/2808025_51.pdf

[77] HEP Website - https://www.hep.hr/ods/korisnici/kucanstvo/tarifni-modeli/34

[78] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

[79] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

[80] ACER Annex 2025 - see previous footnote

[81] ACER Annex 2025 - see previous footnote

[82] https://nodesmarket.com/sthlmflex/

[83] https://www.edsoforsmartgrids.eu/eu-projects/coordinet/

[84] ACER Annex 2025 - https://www.acer.europa.eu/sites/default/files/documents/Publications_annex/2025-ACER-Electricity-Network-Tariff-Annex-I.pdf

such as unrestricted net metering or general connection fee waivers, risk favouring user groups whose cumulative impact on the grid is not negligible.

Importantly, not only exemptions embedded within the tariff methodology need to be evaluated for their impact, but also those rooted in national legislation or sector-specific rules (e.g. the "self-supply" tariff model for households in Croatia described above). These may bypass the regulator's tariff design entirely, yet still significantly affect cost allocation and the fairness of network charges.

3. ANTICIPATORY INVESTMENTS

Anticipatory investments encourage that the grid infrastructure is dimensioned for future needs. The concept emerged to address the need for substantial capacity increase in electricity distribution grids, which is coupled with uncertainty regarding precise pathways and timing.

Most recently, the Commission provided the following definition of anticipatory investments:

"investments into grid infrastructure assets that proactively address network development needs beyond the ones corresponding to reinforcements relating to currently existing grid connection requests by generation or demand projects".[85]

A largely similar definition was also proposed by the EU DSO Entity[86], which, in addition, considers measures for "reinforcing the resilience of power networks" to be covered by the concept as well.[87]

The DNDPs provide a basis for examining such investments. However, the necessary link between the DNDP and the regulatory cost approval process could not be mapped out with sufficient clarity during the research for individual MS.

On a more fundamental level, a forward-looking approach implies reconsidering the assessment benchmark for whether an investment project is required at a point in time. Potentially, solutions would become eligible based on a positive cost-benefit analysis taking into consideration likely future developments, rather than present demand for network services. On another level, already the recognition of "unplanned" investment within a regulatory period and timely recovery of associated cost are beneficial for enabling the green transition. As scarce record could be identified through desk research and expert interviews regarding recognition of forward-looking investment measures, below discussion covers the latter topic area as well (see "Flexibility during regulatory period" below).

Anticipatory investment practices in Denmark and Hungary

Insights on categories of anticipatory investments that are likely to be accepted and interlinkages between approval of grid development measures and DSO revenue regulation would reduce this ambiguity. Denmark is one MS with such a link and is implementing the possibility for DSOs to include "green investments" in their RAB. In addition, Hungary provides an example of linking the regulatory approval of an infrastructure project with its cost recognition for revenue regulation and allows to

[85] European Commission (2025). Commission notice on a guidance on anticipatory investments for developing forward-looking electricity networks, C(2025) 3291 final, 2.6.2025, https://energy.ec.europa.eu/document/download/0c176369-b0c9-416b-9d77-d9f22c482770_en?filename=guidance%20on%20anticipatory%20investments%20for%20developing%20forward-looking%20electricity%20networks.pdf

[86] "Anticipatory investments are those resulting from a process aimed at identifying and executing investments that proactively address expected developments, looking beyond immediate needs of generation or demand into the mid and long-term while assuming with sufficient level of certainty that new generation and/or demand will materialise, even if potential low utilisation could arise in the short term, and considering the negative impacts of delaying the decarbonisation process due to a lack of grid capacity as well as the increased costs of expanding in several stages".

[87] EU DSO Entity (2025). Anticipatory investments. An initial regulatory discussion. Task force in investment funding and finance. https://eudsoentity.eu/wp-content/uploads/2025/02/Paper-on-anticipatory-investment_FINAL-PDF.pdf

invest in higher capacities based on anticipated higher demands. Consequently, these MS are examples for selected practices to allow use of anticipatory investments.

a) Denmark

Context: Under the revenue cap regulation in place in Denmark, DSO's revenues are limited to the sum of a cost framework (consisting of depreciation and OPEX) and a rate of return on the total return base (representing the invested capital). The rules for determining the revenue cap are set forth in the latest Ministry of Climate, Energy and Utilities's Executive order on revenue limits for network companies (BEK nr 1737 of 30/12/2024)[88]. The overall approach to the cost framework focuses on efficiency, as the average expenses of the previous regulatory period serve as a reference for a given period. At the same time, ex-post adjustments are possible (i) automatically due to a change in service level and (ii) upon DSO's request and approval by the regulator ("approval-based"), in certain cases due to significantly higher expenses incurred.

Content: Since 01.01.2025, following a political agreement[89], three elements apply to ensure that the DSO revenue regulation accounts for the future grid expansion and reinforcement:

- Automatic indicator (for low voltage grid): the cost framework and total rate of return are adjusted with an increased number of meters (excluding production meters), number of stations and/or amount of electricity delivered in the low-voltage grid[90]. A 1%-increase in each of these parameters leads to a 0.43%-increase in the revenue cap, respectively[91] (§25 BEK nr 1737). The weighting is based on projections by the Danish Utility Regulator, subject to regular revisions under a methodology to be developed by the Danish Energy Agency[92], and aims at covering additional cost associated with a growing number and consumption volumes of household customers connected in the low voltage. The underlying proposal by the Danish Utility Regulator highlights that any reduction in the investment required for accommodating the surplus in kWh delivered in the low-voltage grid that is achieved through demand-side flexibility would benefit the DSO, at least until the next revision of the automatic indicator.[93] This can be viewed as an imbedded incentive for the use of flexibility.

- Medium voltage surcharge: approval-based revenue cap adjustment can be made for significantly higher cost due to connecting new or expanding capacity for existing consumers in the medium-voltage grid (§33 BEK nr 1737).

- High voltage surcharge: approval-based revenue cap adjustment is possible to reflect expansion or reinforcement of the high-voltage grid to connect consumption or large new generation units, whereby "forward-looking comprehensive solutions that handle both current and expected future electricity consumption" are expressly mentioned (§31 BEK nr 1737).

---

[88] BEK, https://www.retsinformation.dk/eli/lta/2024/1737

[89] Robuste rammer for elnetvirksomhedernes økonomi. 10.06.2024. Stemmeaftale mellem Regeringen (Socialdemokratiet, Venstre og Moderaterne), Socialistisk Folkeparti, Liberal Alliance, Det Konservative Folkeparti, Enhedslisten, Radikale Venstre, Dansk Folkeparti og Alternativet, https://www.kefm.dk/Media/638536021190722676/Aftaletekst.pdf

[90] The base year for determining the change in the amount of electricity delivered is the year in the period 2018-2024 with the highest amount delivered, excluding 2021 (where an unusually high consumption was observed). See: Høringsnotat vedr. udkast til bekendtgørelse om indtægtsrammer for netvirksomheder, Energistyrelsen, 2025, https://www.ft.dk/samling/20241/almdel/kef/bilag/131/2967880.pdf

[91] A simultaneous 1% increase in the number of meters, 1% increase in the number of stations and 1% in the amount of electricity delivered lead to a cumulative increase of the revenue cap by 1,29 %. See ibid.

[92] The Danish electricity and national gas markets 2023, Forsyningstilsynet, 2024, https://www.ceer.eu/wp-content/uploads/2024/10/The-Danish-Electricity-and-Natural-Gas-Markets-2023_final.pdf

[93] Automatisk indikator som tillæg til elnetvirksomhedernes indtægtsrammer. Analyse 7, Forsyningstilsynet, 2024, https://forsyningstilsynet.dk/Media/638403091732856856/Analyse%207%20-%20Automatisk%20indikator%20som%20till%C3%A6g%20til%20elnetvirsomhedernes%20indt%C3%A6gtsramme.pdf

On the generation side, grid connection of renewable generation units qualifies for a revenue cap adjustment, without differentiation according to the voltage level (§32 BEK nr 1737).

Finally, adjustments are foreseen for cost of implementing changed legal requirements, including authority-approved infrastructure projects (§28 BEK nr 1737).

Looking beyond the grid capacity expansion to accommodate renewables, investments for enhanced grid security are also considered in the revenue cap regulation through an approval-based adjustment for:

- additional expenses for replacing headlines with cables for reasons of physical grid security (§35 BEK nr 1737), and

- legally mandated investments into network resilience, including both physical and cyber security[94] (§28 BEK nr 1737).

Evaluation: The described framework enables recognition of grid investment measures – as they are incurred – via the revenue cap adjustment mechanism through several provisions. For high voltage grid expansion, solutions that take into account expected future consumption are expressly included as a basis for approval-based adjustment. For low voltage, the automatic indicator appears to accommodate the risk of dimensioning the grid expansion ahead of actual need at least partially: while the number of meters and amount of electricity delivered reflect actual growing electrification, the number of stations is independent from the use level of the grid infrastructure. At the same time, with the former two parameters, an incentive is in place to ensure that newly built infrastructure components are used to accommodate growing consumption. Most importantly, adjustment for expenditures in connection with authority-approved infrastructure projects creates a link between the investment approval process and the DSO revenue regulation.

b) Hungary

Context: In Hungary, electricity DSOs are subject to a price-cap regulation. System charges are determined by the regulator, MEKH, annually based on justified cost, subject to a cost efficiency benchmarking, and the projected amount of electricity delivered.[95] A detailed methodology for assessing whether or not the costs claimed by grid operators are justified is set forth in MEKH's methodological guidelines for determining the reasonable costs of electricity network licensees[96] ("MG-1").

Content: While the least cost principle underlies the review of cost items to be included in the justified cost base, the assets and cost review methodology provides that the regulator should consider the recognition of a specific incentive item enabling the necessary network investments at an appropriate level (I.3.3. MG-1). The underlying Art. 412(5) of the 86 Act of 2007 on electricity ("VED") provides for incentives for grid operators to enhance security of supply in the short and long term. Consideration of the long-term perspective included in the assets and cost review by the regulator could, in principle, be interpreted to cover forward-looking investments. At the same time, MG-1 contains no detailed provisions in this regard.

Recognition for the price cap regulation is ensured for justified cost of investments included in the network development plan (Art. 25(6) VED). In this context, MEKH's risk assessment methodology

[94] See Act on strengthened preparedness in the energy sector, Lov nr 258 af 06/03/2025 om styrket beredskab i energisektoren, available online: https://www.retsinformation.dk/eli/lta/2025/258, and Executive order on emergency preparedness and resilience in the energy sector, available online: https://ens.dk/media/6550/download

[95] The system charges methodology for the current regulatory period is set forth in MEKH's methodological guidelines on the system for setting annual electricity system charges ("MG-2"): A Magyar Energetikai és Közmű-szabályozási Hivatal módszertani útmutatója a villamos energia rendszerhasználati díjak évenkénti megállapításának rendszeréről a 2025. január 1. - 2028. december 31. közötti árszabályozási ciklusban, available online: https://net.jogtar.hu/jogszabaly?docid=a2400004.mek

[96] Módszertani útmutató a villamos energia hálózati engedélyesek indokolt költségeinek meghatározásához (a 2025-2028. évi árszabályozási ciklus induló árainak meghatározását megelőző eszköz- és költség-felülvizsgálathoz), available online: https://mekh.hu/download/6/0d/81000/M%C3%9A%201%20%28TELJES%29%20-%201018.pdf

for evaluating gas and electricity infrastructure development projects[97] comes into play. The methodology was developed under Art. 17 of the TEN-E Regulation[98] ("TEN-E") regarding risk-related incentives for infrastructure projects of common interest. Noting that the methodology refers to "infrastructure development projects in the case of higher risks", the possibility of its application or extension to any DSO investments into grid development could not be investigated within the scope of this study. Nevertheless, the approach could be interesting for anticipatory investments in general, as they are characterised by higher risk. The cost benefit analysis involves quantitative assessment of all project-specific risks (including planning risks and risk of decreased revenue, e.g. if new grid components are underutilised) and an evaluation of the project's societal impact according to the technical, environmental, economic, social, safety and security of supply dimension and cross-sectoral impacts. If the financial gap is not at least off-set by the cumulative social benefits, the project should be rejected. In case of a positive value, associated investment is recognised when determining the system charges.

Evaluation: As no *ex-ante* review of assets takes place, there is no time lag in the consideration of approved investments. Thus, for anticipatory investments the focus lies on the approval of grid development projects by the regulator. The cost benefit assessment methodology initially adopted under the TEN-E Regulation for projects of common interest could be used and further developed to cover any forward-looking investments into distribution grids.

The adjustment rule refers to increasing the cost framework and the total basis of return in the regulatory year in which the additional cost was incurred. Thus, no differentiation is made between CAPEX and OPEX, which could lead to a distortion when choosing an appropriate measure. In addition, §41 (6) BEK nr 714 provides for indexation of adjustments due to higher (or lower) OPEX. Overall, the regulations described appear to secure cost recovery with no significant time delay. As adjustments based on substantially higher operating cost are enabled next to recognising additional investments, an otherwise possible disincentive for anticipatory investment is removed.

4. INCENTIVES FOR SMART GRID INVESTMENTS

Smart grid describes various solutions based on sensors, ICT and data processing for a more intelligent and efficient system integration of new generation, storage and consumers.[99] In particular, smart metering is a key prerequisite for using flexibility and, thus, for system integration of renewables. Technologies like e.g. overhead line monitoring (dynamic line rating) enable more efficient use of existing power lines and, thus, reduce the need for grid expansion. The implementation of smart grid solutions includes investment into hardware (metering devices, sensors, hardware components for ICT and data processing) and software. Hardware qualifies as fixed assets (equipment), while software and data are intangible assets. In addition, investing in those assets leads to operating costs related to their operation and maintenance.[100] Also, investments in projects required to pilot smart grid innovations need to be considered.[101]

[97] Methodology for the evaluation of the higher risks of gas and electricity infrastructure development projects, MEKH, 2023, available online: https://mekh.hu/download/9/b8/51000/Risk_Methodology_2023_MEKH_EN_FINAL.pdf

[98] Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013. Consolidated text, http://data.europa.eu/eli/reg/2022/869/2025-02-05

[99] The Commission defines a smart grid as "an electricity network that can cost efficiently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety". See: Definition, expected services, functionalities and benefits of smart grids. Commission staff working document, 2011, SEC:2011:0463:FIN:EN:TXT.pdf

[100] EU DSO Entity (2025). Anticipatory investments. An initial regulatory discussion. Task force in investment funding and finance. https://eudsoentity.eu/wp-content/uploads/2025/02/Paper-on-anticipatory-investment_FINAL-PDF.pdf

[101] Cambini, C., Meletiou, A., Bompard, E., Masera, M. (2016). Market and regulatory factors influencing smart-grid investment in Europe: Evidence from pilot projects and implications for reform. Utilities Policy (40), p. 36–47, http://dx.doi.org/10.1016/j.jup.2016.03.003

The traditional approach of calculating the return based on the CAPEX does not incite OPEX-driven investments, such as for smart grid systems. These flexibility investments, often characterized by their digital, data-driven, and service-oriented nature, tend to reduce the need for conventional asset-focused infrastructure but remain underrepresented in some of the current regulatory approaches. It is recommended to deepen the insights on MS with more agile investment frameworks.

Performance-based incentives in Denmark and Ireland

Based on the information gathered, Denmark and Ireland stand out as potential best practices due to their different performance-based incentives, including incentives for smart metering. Additionally, Ireland applies incentives for flexibility and provides mechanisms for uncertainty, flexibility, innovation and R&D.

a) Revenue cap adjustment for higher smart meter-related cost in Denmark

Context: In Denmark, the need for investment into smart grids was recognised and anticipated already by 2014.[102]

Content: The revenue cap regulation enables both CAPEX- and OPEX-related, approval-based adjustments compared to the previous RP average (see above) to account for significantly higher costs due to replacement and upgrade of electricity meters to remotely read electricity meters, acceleration of investments in remotely read electricity meters and submission of hourly metered consumption data to the data hub (§29 (3) 1) BEK nr 1737). Smart grid technologies beyond smart meters can be eligible for adjustment under §27 (1) BEK nr 1737 for legally mandated (by an authority or Energinet) technical adaptation of existing installations.

Furthermore, the above-mentioned revenue cap adjustment possibility for cyber security measures (§28 (3) 2) BEK nr 1737) can at the same time be seen as an enabler for smart grid implementation.

Evaluation: The revenue cap in place considering both CAPEX and OPEX and the fact that adjustments in case of significantly higher expenditures are possible to both the cost frame and the total revenue contribute to a favourable regulatory framework for smart grid investments.

b) Flexible regulation and clear objectives in Ireland

Context: Ireland's sole DSO is regulated according to a revenue cap system. Unlike in Denmark, where the basic revenue cap is, in principle, determined based on the previous RP's average cost, the Irish approach complements a review of historic CAPEX and OPEX with an *ex-ante* forecast for the RP. In addition to cost incentives, the framework includes performance incentives and a set of instruments called Agile Investment Framework. The cost incentives are linked to an *ex-post* review to assess if expenditures were incurred efficiently and allow only those. Objectives targeted by the performance incentives include e.g. continuity of supply, smart metering, improved visibility of conditions on the low voltage network, DSO/TSO coordination and timely issuing of connection offers. The incentives operate with objective-specific upside (rewards) and downside (penalties) adjustments to the allowed revenue. The Agile Investment Framework consists of five elements[103], including an uncertainty mechanism, a flexibility mechanism and an innovation and R&D mechanism.

---

[102] En fremtidssikret regulering af elsektoren. Afsluttende rapport. Udvalg for el-reguleringseftersynet, 2014, https://ens.dk/sites/default/files/media/documents/2024-11/en_fremtidssikret_regulering_af_elsektoren_web.pdf, as cited in: Mortensen, B. O. G., The Danish income cap regulation in the power supply sector: A legal perspective considering the green transition. In: Energy regulation in the green transition. Danish Utility Regulator's anthology project series on better regulation in the energy sector, Vol 1, p. 65-73, https://forsyningstilsynet.dk/Media/638225132312465956/danish-utility-regulators-anthology-project-series-on-better-regulation-in-the-energy-sector-vol-1.pdf

[103] The other two elements are a CAPEX adjustment mechanism and an ongoing regulatory review of TSO initiatives by the TSO Monitoring Committee. These are not discussed here, as they apply to the TSO only.

An accompanying reporting framework allows the regulator to monitor the progress towards the outputs during the RP, including annual revenue reviews.[104]

Content: Implementation of smart grid technologies by the DSO is incentivised through several instruments under the revenue cap regulation.

- Flexibility mechanism: The Flexibility mechanism under the Agile Investment Framework allows the DSO to shift revenue allowances between CAPEX and OPEX, if during a RP it identifies that an outcome for which a CAPEX allowance was foreseen at the beginning of the RP can be achieved more efficiently through OPEX-incurring measures. A vice versa reallocation from OPEX to CAPEX is possible as well.

- Smart metering incentive: To support the rollout programme, a smart meter performance incentive is in place to achieve defined outputs. Notably, the upside and downside design varies for each objective set under the incentive. For the number of smart meters deployed, the reward for performance is higher than the penalty for underperformance, which is explained by overall favourable conditions for deployment. Conversely, for the smart meter functionality delivery, a larger upside is provided, as this category is expected to be more challenging to achieve. Regarding the aspect of customers' satisfaction around the smart meter deployment process, the upside and downside are equally weighted.

- Visibility incentive: The development of a system to increase the visibility of the low voltage network for the DSO is backed by a performance incentive. The resulting digitalisation of the grid should improve system integration of renewables, distributed generation and storage and facilitate energy exchanges between citizen energy communities and renewable energy communities.

- Flexibility incentive: accompanies implementation of a flexibility procurement mechanism by the DSO.

- System control uncertainty mechanism: An approved work programme for the system control including smart grid technologies is accompanied by a dedicated uncertainty mechanism to ensure delivery.

- Joint TSO/DSO coordination: Under the respective performance incentive, TSO/DSO collaboration expressly includes joint piloting and deployment of new technology, which may also include smart grid solutions.

- Innovation and R&D incentive: Finally, expenditures for innovative projects (including those for smart grid solutions not otherwise covered in the revenue regulation are eligible for the Innovation and R&D mechanism under the Agile Investment Framework. Projects submitted by the DSO are reviewed by the regulator on a case-by-case basis.

For the next regulatory period 2026-2030, CRU plans to formulate driving "smarter, flexible, more digitally enabled networks and energy system" as one of six objectives.[105]

Evaluation: The Irish regulatory framework combines a wide range of instruments to ensure timely and cost-efficient deployment of smart grid technologies. The flexibility mechanism within the Agile Investments Framework allows the DSO to choose the best suited implementation option while the regulator maintains its price control functions through the *ex-post* review. In addition to removing a potential disincentive for OPEX-focused solutions, the regulator proactively sets and monitors

[104] PR5 regulatory framework, incentives and reporting, Decision paper, CRU, 2020, https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU20154-PR5-Regulatory-Framework-Incentives-and-Reporting-1.pdf

[105] Price review six strategy paper, CRU, 2024, https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/PR6-Strategy_Paper-.pdf

implementation of specific objectives regarding smart meters and other smart technologies, based on policy priorities, historic and current developments.

5. FLEXIBILITY DURING REGULATORY PERIOD

To improve the flexibility of DSO during the regulatory period and hence approving a fast cost recovery, MS can apply different instruments for adjustments during the set period.

Adjustment instruments in Ireland and Croatia

Croatia applies a cost-plus regulation with one-year regulatory period and Ireland a revenue-based cap and collar system with a five-year regulatory period, including yearly adjustments. The majority of MS uses revenue caps with four- to five-year regulatory period, so that Ireland might provide a best practice for yearly adjustments with a long regulatory period. Croatia is a special case with a short regulatory period and consequently a very low time-delay for cost recovery. Therefore, both MS qualify for potential deep dive countries.

a) Adjusting for cost, timing or output uncertainty in Ireland

Content: The Uncertainty mechanism as part of the Agile Investment Framework (see above) allows the DSO to claim additional revenue allowance in the following cases during a yearly revenue review:

- New domestic connections: the number of new connections exceeds (or is forecasted to exceed – based on new data) the initially forecasted number.
- Pay-as-you-go (PAYG) meters[106]: more PAYG meters are to be installed than forecast (in analogy to new connections).
- Large customers: Due to limited predictability of connection requests by large customers, additional associated cost incurred is eligible for the revenue allowance. There is a materiality test mandating that the high voltage allowance needs to be exceeded by at least 10% in the forthcoming calendar year. Further proof requirements apply to ensure the adjustment is justified.
- Low carbon technology (LCT)[107]: The instrument addresses low voltage and medium voltage reinforcement investments required as a result of LCT uptake but not covered by the *ex-ante* revenue allowance. The reinforcement can be pursued not only based on actual connection requests but also inter organisational data sharing, smart meter or other monitoring data analysis. The forecast needs to be continuously updated with actual data, which is considered for the annual revenue review. The DSO has to prove that using flexibility to defer the requested reinforcement has been explored and the proposed investment is the least whole-life solution.
- Force majeure: Costs incurred due to exceptional weather events can be claimed under this mechanism.
- System control (discussed above in the context of smart grid)
- Low voltage model: Adjustments are provided for installation of congestion management and low voltage monitoring applications.

---

[106] A PAYG meter is a meter that can be programmed to limit a consumer’s off-take at the metering point to a pre-paid energy amount.

[107] In addition to the described mechanism, an allowance for converting rural network from 10 to 20 kV for increasing the network capacity is envisaged. See also: Water and energy connections in rural areas and the islands, ESB Networks, 2023, https://data.oireachtas.ie/ie/oireachtas/committee/dail/33/joint_committee_on_social_protection_community_and_rural_development_and_the_islands/submissions/2023/2023-12-06_opening-statement-nicholas-tarrant-managing-director-esb-networks_en.pdf

Annex 17 to CRU's decision on the PR5 price review details the regulator's approach for each of the above-listed uncertainty mechanisms. In particular, each of them is characterised in terms of three uncertainty aspects: cost, time and output uncertainty.

As the application of the uncertainty mechanisms, typically, requires adjusting the ex-ante revenue allowance,

Evaluation: The reasons for the revenue cap adjustment during a RP are largely comparable to those in place in Denmark (discussed in the context of anticipatory investments above). A key difference is that in Denmark adjustments are either linked to objective criteria and, thus, automatic or subject to the regulator's approval on a year-by-year basis during the RP – while the Irish framework grants freedom to the DSO to choose the optimal solution and enforces the efficiency check *ex post*, at the end of the RP. The DSO remains fully in charge of investment decisions, as it is best placed to choose the most appropriate solution. At the same time, it bears the risk that expenditures incurred may not be allowed for recovery if the DSO fails to justify them during the *ex-post* review at the end of the RP. The design of the cost incentive ensures that no hindsight regulation takes place, and cost-efficiency is accessed based on information that was (or should have been reasonably) available to the DSO at the time of making the expenditure decision, i.e., disregarding subsequent information.[108] This approach allows the NRA to maintain the cost control while accommodating for uncertainty.

b) Short regulatory period in Croatia

Context: In Croatia, the sole electricity DSO is regulated based on the cost-plus approach with incentives. Detailed rules on determining allowed revenue are set forth in the Croatian regulator's HERA Methodology for determining the tariff rates for the distribution of electricity[109]. The regulator sets grid tariffs for a regulatory year at a level that the planned total revenue to be received is less than or equal to the planned eligible costs plus incentives for that regulatory year. The incentives address the amount and price of electricity to compensate grid losses. A short regulatory period of one year is a distinctive feature of the framework.

Content: The grid tariffs for the next regulatory year (Y+1) are based on:

- recognised realised costs, incentives and revenues from the previous regulatory year (Y-1),
- recognised planned costs and revenues in the next regulatory year (Y+1),
- taking into consideration the estimated recognised costs and revenues in the current regulatory year (Y), and
- recognised planned costs and revenues in the following regulatory years (Y+2 and Y+3).

In addition, a procedure is included in the framework for adjusting the amounts of tariff items in the current regulatory year for its remaining part. However, the possibility of submitting adjustment requests under this mechanism was paused at least until 31.03.2024.[110][111]

---

[108] PR5: Design of cost incentive for the electricity network lisensees, Final report, CEPA, 2020, https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU20150-PR5-Design-of-cost-incentive-for-the-electricity-networks-1.pdf

[109] Metodologija za određivanje iznosa tarifnih stavki za distribuciju električne energije, HERA, 20.7.2022, https://narodne-novine.nn.hr/clanci/sluzbeni/2022_07_84_1283.html

[110] Annual report for 2022, Croatian Energy Regulatory Agency, 2023, https://www.hera.hr/en/docs/HERA_Annual_Report_2022.pdf

[111] Summary of the annual report 2023, Croatian Energy Regulatory Agency, https://www.hera.hr/en/docs/HERA_Annual_Report_2023.pdf

Evaluation: As the eligible CAPEX and OPEX are reviewed on a yearly basis and, moreover, the allowed revenue is determined based on planned cost for the regulatory year in question, rather than based on historic values, the DSO can get their cost pre-approved shortly before they are incurred. Thus, it faces no time gap between committing to new investments and their recovery through grid tariffs. Neither is there a risk of failing cost recognition, as may be the case with an *ex-post* review at the end of a longer regulatory period. At the same time, the approach is not per se transferable to incentive regulation based on a longer regulatory period. Arguably, certain elements of year-by-year planned cost review by the regulator may be considered as a possible element of a framework for treating anticipatory investments, for instance when linked to step-wise approval of design, permitting and construction[112]. However, regular annual reviews can result in higher cost of regulation and compliance costs.

112 As suggested e. g. in: Commission notice on a guidance on anticipatory investments for developing forward-looking electricity networks, C(2025) 3291 final, 2.6.2025, https://energy.ec.europa.eu/document/download/0c176369-b0c9-416b-9d77-d9f22c482770_en?filename=guidance%20on%20anticipatory%20investments%20for%20developing%20forward-looking%20electricity%20networks.pdf

5. DESIGN FEATURES FOR TIMELY AND TRANSPARENT TREATMENT OF GRID CONNECTION REQUESTS

The further adoption of electric cars, heat pumps, renewable energy sources, and other grid users can be hindered by non-transparent or delayed grid connection requests. Fifteen MS have already seen or have reported the first signs of queues[113] when they are dealing with grid connection requests for a wide variety of reasons (see Appendix 1). This relates to the administrative process, its timeliness and the ambiguity around the grid users' basic eligibility for the connection throughout the planning phase. The process is hampered by a lack of openness on the networks' remaining capacity for new connections. A rise in connection requests (which frequently corresponds to a particular level of technology adoption), a lack of digitalization and understaffing contribute to delays in processing the requests. **Infobox 4** summarizes current policy action at the EU level for this topic area.

Infobox 4

Box 4: EU Policy Action on the Treatment of Grid Connection Requests

The treatment of grid connection requests has recently become a key topic of discussion in EU energy policy, shaping both strategic approaches and legislative initiatives aimed at improving transparency, efficiency, and flexibility. As grid access demand grows – particularly for renewable energy projects – the EU has introduced regulatory measures to ensure timely, coordinated, and future-proof connection processes. These actions focus on enhancing information availability, streamlining administrative procedures, and establishing flexible connection agreements to address network constraints while supporting the overall energy transition.

The Grid Action Plan (GAP) – Action 6 sets out key measures to enhance information availability and connection processes. System operators should provide clear, granular, and regularly updated data on grid hosting capacities and connection request volumes. By harmonizing definitions across EU countries, this would enable a pan-European overview of available grid capacity and the status of connection requests. This can help to understand the benefits of flexible (non-firm) connections to the grid, if the required grid extension has not been built. Regulatory authorities should establish frameworks for non-firm connection agreements which ensure that system operators do not delay grid expansion when it is the best solution. Only in cases where grid reinforcement is not economically viable, non-firm connections may serve as a long-term alternative. Moreover, ENTSO-E and the EU DSO Entity should help system operators digitize and streamline connection request procedures.

The Electricity Market Directive (EU 2019/944) strengthens transparency requirements by mandating that distribution system operators (DSOs) provide system users with the necessary information for efficient grid access (Article 31(3)). This is further reinforced by their revised version (EU 2024/1711), which introduces flexible connection agreements (Article 6a). These agreements are designed for areas with limited or no grid capacity to still allow for new connections. Also, with flexible connection agreements DSOs must ensure to do not delay necessary reinforcements. Non-firm connections can be converted into firm connections once the network is expanded as it is mentioned in the GAP as well. Where grid expansion is not the most efficient solution, flexible connections may serve as a permanent alternative. These agreements should define firm and flexible electricity injection/withdrawal limits, outline applicable network charges, and set clear contract durations with a timeline for full firm capacity access.

[113] Note: Data collection for the individual MS showed that the cause of queues is not always clearly identified. This study focuses on requests for grid connections rather than follow-up processes. However, queues often arise in subsequent stages, such as the planning or construction phases, or as a result of resources being tied up in these stages. This must be taken into account when classifying statements on lead times.

Additionally, Article 31(3a) of EU 2024/1711 mandates that DSOs must allow system users to request grid connections and submit relevant documents in digital form, reducing administrative burdens and improving efficiency.

Together, these measures represent a comprehensive EU strategy to modernize and accelerate grid connection processes, ensuring that energy system expansion keeps pace with growing renewable energy integration and electricity demand.

In this context, the target for the topic area 'timely and transparent treatment of grid connection requests' is to identify key design features addressing these problems. For the data collection within the EU 27, we explore the topic area along three **subtopics**, namely:

1. Determination of grid connection potential and transparency
2. Measures in case of lacking capacity
3. Design features for the process of grid connection requests

To summarize the breakdown within the topic area**, Table 8** shows the subtopics and the respective design categories.

Table 8: Subtopics and design categories for topic area 3

3. Topic area: Timely and transparent treatment for grid connection requests	
Subtopic 1:	**Determination of grid connection potential**
Design category 1	Methodology for Grid Hosting Capacities
Design category 2	Transparency Platforms for Potential Grid Users
Design category 3	Unified Technical Requirements for Grid Users to be Connected
Subtopic 2:	**Measures in case of lacking capacity**
Design category 1	Assignment of Grid Capacity
Design category 2	Conditional Grid Connections
Subtopic 3:	**Process for grid connection requests**
Design category 1	Lead Time for Processing Grid Connection Requests
Design category 2	Procedures for Processing Grid Connection Requests
Design category 3	Administrative Burden

The first subtopic reflects on how the grid hosting capacity is determined and communicated to the potential grid users, which is critical for ensuring **transparency** of grid connection requests. The second subtopic examines how the access is allocated in the case of lacking capacity and which incentives and other measures are implemented on the grid users' side. The third subtopic covers procedural aspects while processing the grid connection requests. **Timeliness** is directly captured in the design category relating to lead time but also embedded in other categories of subtopics 2 and 3. This is because the full timeline of grid connections is a multi-stage process structured differently across MS.[114]

[114] Cf. Wind Europe (2024). Grid access challenges for wind farms in Europe, https://windeurope.org/intelligence-platform/product/grid-access-challenges-for-wind-farms-in-europe/

As in the previous chapters, three institutional levels characterise the design of the subtopics: EU level, NRA level and DSO level. At the EU level, this topic area is relatively new on the agenda. The GAP foresees to harmonise the definitions for available grid hosting capacity. The new rules on the design of the electricity market from 2024 require DSOs to provide regular information on free grid capacity and MS regulators to create the framework for DSOs to offer flexible grid connection contracts.

On the side of the NRAs, relevant activities include establishing frameworks for non-firm connection agreements and a harmonised definitions for available grid hosting capacity. On the side of the DSOs, there is discussion around transparent, understandable, granular and regularly updated information on grid hosting capacities and connection request volumes. The processing of grid connection requests should be streamlined and digitalised. The technical requirements for generation and demand connection should be unified.

The national policy discourses also consider unifying the connection requirements and definition of available grid hosting capacity, as well as streamlined and digitalised processes. However, national level requirements or guidelines may face enforcement issues given organizational constraints, which results in heterogeneous practices of the DSOs and uncertainty for the grid users. The following explains the design categories across all three levels.

5.1. Design categories

DESIGN CATEGORIES FOR 1: Determination of grid connection potential

The first design category reflects on how the DSOs determine the grid hosting capacity, whereas the second and third design categories focus on how this information is shared with the potential grid users and which technical requirements are imposed on the grid users.

1. **Methodology for Grid Hosting Capacities:** This clarifies how the DSOs determine the grid hosting capacity (e.g. individual or heuristic assessment, treatment of speculative grid connections).

2. **Transparency Platforms for Potential Grid Users:** The second category considers how this information is shared with the potential grid users (e.g. with interactive grid maps, capacity maps or similar tools)

3. **Unified Requirements for Grid Users to be Connected:** This aspect addresses to which extent the grid connection requirements for potential grid users are unified among DSOs and how such standardization is operationalized.[115] Exemptions for certain grid users to file grid connection requests are captured as well.

DESIGN CATEGORIES FOR 2: Measures in case of lacking capacity

Lack of capacity is identified as a new but spreading reality for European DSOs. While the first design category outlines how the access is assigned in the case of lacking capacity, the following design category defines the potential measures on the side of DSOs to assign the lacking capacity.

1. **Assignment of Grid Capacity:** The first design category examines how formal processes are established within the MS for assigning grid capacity in situations of limited availability. It assesses the principles used to determine allocation priorities and evaluates the extent to which these processes comply with the requirements of Article 6 of the Electricity Market Directive (EU 2019/944) concerning non-discriminatory third-party access. Common approaches mentioned within literature and confirmed also by interviews across multiple DSOs are "First-come-first-

[115] Certain technical requirements must follow the network code for demand connection. The focus here is on national processes in the handling of grid connection requests beyond the technical aspects.

serve", queuing systems, applying time windows, prioritization of small-scale grid users, ranking according to the degree of grid impact, or avoidance of simultaneity.

2. **Conditional Grid Connection**: Conditional grid connection is one option to connect grid users and operate the grid in the presence of lacking grid capacity. The design category clarifies if they are available and if yes, how they are implemented (e.g. non-firm grid connection requests).

DESIGN CATEGORIES FOR 3: Process of grid connection requests

One measure to mitigate delays on the side of the DSOs is to limit the allowed lead-time for processing grid connection requests (first design category). On the side of the grid users or supporting service providers, the process can be time-intensive and complex, a) if it differs between the DSOs (second design category) and b) if each process involves a high administrative burden (third design category).

1. **Lead-Time for Processing Grid Connection Requests:** In order to ensure a timely grid connection, national-level requirements may introduce a maximum lead time for processing grid connection requests and default actions in case of surpassing lead time (e.g. default acceptance). Deadlines could be set on both on the side of the customer and the DSO. The focus of the study is on the DSO side since high levels of fragmentation on the customer side obstruct a clear view on the timelines kept by applicants.

2. **Procedures for Processing Grid Connection Requests:** The process of grid connection requests can also be made faster procedurally if it is unified among the DSOs in one MS and digitalized in order to simplify the process for grid users and service providers.

3. **Administrative Burden:** High administrative burden exists if the process involves multiple requests at different institutions, which requests different sets of information. The burden is considered from the perspective of the grid user. Also, here digitalization can assist in alleviating this burden by enhancing transparency and streamlining process management for grid users.

5.2. Analysis

1. DETERMINATION OF GRID CONNECTION POTENTIAL

Overall, the third topic area is currently the least formalized regarding the link between national requirements and actual implementation. The legal basis in MS is often only a high-level call for timely connections and it is not transparent to what extent the rules set by NRAs and other administrative bodies are being met or are feasible to meet by DSOs, especially in MS with highly heterogenous DSOs. While grid user associations have been voicing concerns about grid connection potential, this topic has received relatively little attention from the DSO perspective in the multi-country reports to date, with the notable exception of the DSOs Fit for 55 report[116].

Regarding the **grid hosting capacity**, there is little information publicly available on how this is determined (e.g. actual data vs. assumptions about simultaneity). This includes variation regarding the basic definition of capacity. For example, AT distinguishes between booked and available capacity explicitly, but there is no uniform approach to making such distinctions across Europe. MS differ not only widely in how grid hosting capacity is determined, but also in how it is *communicated*. The most common practice is the use of a capacity map, which is often done at national level (e.g. AT, EE, FI, IE, SK). However, the use of a map is not the only approach taken, there are different comparable information tools that serve the same purpose (e.g. FR, SI). For example, Portugal has a search tool

---

[116] EU DSO Entity (2023) : DSOs Fit for 55, self-published, available online: https://eudsoentity.eu/wp-content/uploads/2024/09/DSO_SolarReport_2023-v11.pdf (last view: 14/01/2025)

by Zip Code that provides information on grid capacity but does not have a map representation.[117] Information on the inputs and assignments behind the capacity maps is widely not transparent. Exceptions are the Nordic countries, but even within that group there appears to be no uniform approach to the determination of grid capacity.

This gap in transparency is also recognized at the European level as a barrier to market integration. As part of the measures of the grid action plan, efforts are underway to define, communicate and share information about grid hosting capacity. **Infobox 5** provides a brief overview of the European initiative in this regard.

Infobox 5

BOX 5: Ongoing Efforts to Define and Measure Grid Capacity[118]

As part of Action 6 of the GAP regarding grid hosting capacities, there have been collaborative efforts between ENTSO-E and EU DSO Entity to work on definitions of grid capacity with harmonized parameters and to establish an information portal (user-oriented) to make grid capacities transparent. This platform is currently in the stage of stakeholder consultation and expected to go live in 2026 with the objective of a pan-European overview.

From the conceptual stage, this proposal for a common platform dubbed "Capacitypedia" includes in particular:

- MS pages with current status, responsibility for publication, and links/contacts
- TSO and DSO grid hosting capacities, including links to national systems and definitions/methodology documents, and applicable disclaimers

The vision for this portal is summarized as follows:

"[The portal] serves as a single-entry point for users, enabling easy navigation of grid hosting capacities and providing access to websites displaying current grid hosting capacity status".

Apart from the methodology, there are also **differences in organization**. Some MS have the DSOs themselves at the centre of the process (e.g. IE, DE, NL). The results show that the NRAs don't play a key role in most cases, as called for in the GAP. While the responsibilities are not made transparent in the high-level documents, the interviews confirmed the crucial role of the DSOs as main player currently. In summary, the results support that the GAP's call for "harmonized definitions for available grid hosting capacity" is currently not a reality across MS at the distribution grid level. Nonetheless, AT serves as an example where such a harmonized definition exists at a specific voltage level. Although not applicable across the entire distribution network, there is a legislative foundation for a consistent definition within the country, as specified in § 20 ElWOG (3). The NRA in AT has issued a directive for calculating available capacity at grid level 4, which corresponds to transformer stations between high and medium voltage.

---

117 See p. 23 and 24 of : EU DSO Entity (2023) : DSOs Fit for 55, self-published, available online: https://eudsoentity.eu/wp-content/uploads/2024/09/DSO_SolarReport_2023-v11.pdf (last view: 07/05/2025)

118 Presentation by ENTSO-E and EU DSO Entity from 11th Energy Infrastructure Forum. Available online at https://energy.ec.europa.eu/events/11th-energy-infrastructure-forum-2025-06-02_en

Regarding **transparency** of the grid hosting capacity towards grid users, a particular concern from the screening of capacity maps is the disparate quality of available tools. While many MS offer some form of capacity map, the useability for the grid users is very different. Strong examples for capacity mapping practices overall include IE, PT, and AT. The full list of tools with links and descriptions is included in Appendix 1.

Selected attributes that could serve as best practices are for example that maps and related tools are: (1) interactive (e.g. DK, EE), (2) searchable (e.g. BG), (3) downloadable (e.g. IE) and (4) follow open data practices (e.g. CZ). In terms of **granularity**, information at substation level is an emerging best practice followed by the more advanced tools. In addition, some maps distinguish explicitly between user types (e.g. BG, IE). The relevance of this distinction could be especially relevant in MS with regional disbalances between production surplus and consumption surplus areas.

The quality aspect also concerns the **actuality** and frequency of updates. Quarterly updating appears to be the highest standard as also requested by the Electricity Directive (EU 2024/1711 Article 31 (3)), whereas many MS only update annually and in some cases the webpages of the tools do not state the last update more explicitly. In addition, the tools differ in how detailed they are with respect to the **different voltage levels**. Not all maps provide full coverage of the lower grid levels currently.

Most European countries provide grid capacity maps that display the medium-voltage network, typically including transformer stations operating at or around 110 kV. Denmark offers more granularity by including data down to 50 kV, while the Czech Republic is unique in using colour indicators to represent low-voltage grid capacity. Practically, this means that the reported capacities generally do not reflect the situation at the distribution grid level, where individual connection studies for low-voltage connections must be carried out with the relevant DSO.

Some MS explicitly mention a grid level as the focus in the national requirements and procedures (e.g. high voltage in MT, medium voltage in EE), but in many cases, it is not easily transparent how well the maps cover the lower grid levels. As mentioned above the capacity maps in AT focus on HV/MV stations but an interview with a DSO also confirmed efforts to display available capacities at lower voltage levels. This will be done using a three-color indicator to prevent the precise sizing of assets based on the available capacities. By contrast, some MS offer extra support for low voltage customers to get grid access, for example through workshops or webinars on photovoltaic (PV) connections in HR or LT.

From the **grid user perspective**, the access to information and guidance in the process differs. While some MS offer a platform as the single access point (e.g. FR, LT), other MS let the individual DSOs handle the process and the information provision. In some constellations, there is a disconnect between a national-level platform or capacity map on the one hand and the individualized DSO processes on the other hand. For example, DE has a common DSO platform, but for the actual assessment of capacity, users are referred to the individual DSOs. Information provision is also difficult due to fragmentation (see above). There are different forms depending on the technology to be connected (long lists and links to other policy areas, e.g. construction, land use), the processes are not fully shared (e.g. how to define capacity), or information is embedded only in grid codes, but not accessible for customers.

2. MEASURES IN CASE OF LACKING CAPACITY

To understand the implementation of measures in **cases of lacking capacity**, the reference point is the current grid conditions. Heterogeneity in current practices is strongly driven by the extent to which grid capacities are already being reached. Measures taken can be broadly split into: (a) interim measures that bridge gaps until grid reinforcement is possible and (b) deeper overhaul of systems/processes to address volatility of supply and demand as a long-term challenge.

Regarding the basic mechanism, the national legislations are often restricted to basic principles in accordance with European requirements (non-discrimination, transparency), but the operationalization is often not fully specified. First come, first serve is commonly applied, but not always explicit or fully transparent regarding the queue. Several MS do have priorities of some form, but the range of these decisions is wide.

Priorities are given for different reasons, with notable rationales including the following examples:

- Priority RES development based on national law (e.g. in FR)
- Criticality to public services such as hospitals (e.g. in CY), social value (e.g. ES) or infrastructure such as water (e.g. in GR, and NL[119])
- Queueing exemptions for small-scale assets or connections below a threshold (e.g. in HR, SI)
- Economically meaningful connections to medium network (e.g. in HU)
- Alignment with energy and climate policy (e.g. for RES or EV connections in IT)
- Special auctions for larger projects (planned in RO for 2025/2026)
- Priority for connections that actively help relieve congestion (e.g. NL)

The implementation of these mechanisms also differs regarding the extent to which they **shift the incentives on both sides**. This means incentives for grid users to adapt to grid needs, as well as the incentives / requirements for DSOs to speed up grid connections. An interesting example is being tried in DE, where DSOs have the right to dim the loads of controllable assets *in exchange* for the rule that they can no longer deny connection requests if users agree to make the asset controllable. Here, incentives are shifted simultaneously for grid users (make device controllable) and DSOs (do not deny connection). The French arrangement with priority given according to zones for RES development is a different approach to balancing two types of incentives: energy policy and grid users' location choices. Currently, it appears that the incentive structures implicit in grid connection processes between (energy) policy makers, grid operators, and grid users are mixed and heterogeneous in national procedures.

Another aspect related to shifting incentives is pricing through tariffs or **connection cost charging fees**, respectively. As mentioned in Chapter 4 for network tariff regimes, many MS use both shallow (paying only for the actual cost of grid connection) and deep (paying also for the need of grid reinforcement etc.) charging fees. The exact design chosen by a Member State may vary depending on the use case and grid level. In the case of DK, for example, they try to manage connection charges to deal with capacity constraints on the grid by offering discounts on connection charges if the grid user agrees to an alternative connection agreement. Other countries, such as PL ("open market terms") or DE ("hardship condition"), use exceptions to their typical shallow charges in special cases where the shallow charge is economically not viable from the grid perspective. However, the current economic incentives are generally not directly linked to the processing of grid connection applications in order to speed up the procedures or to provide information on grid capacity potential. It was also not possible to draw any direct conclusions from the analysis as to the extent to which locational signals influence time-related aspects of the end-user decision-making process.

MS also differ in their treatment and tolerance of **rejecting grid connections**. In some MS, there is increasingly the need to develop (legal) processes for handling rejections and queueing decisions (e.g. PL, AT, BE). This is typically relayed to NRAs, and especially difficult in cases where queues have already built up, so there is the need to deal simultaneously with backlog and new incoming applications (e.g. IE as an extreme case). In addition, several MS have also introduced mechanisms for that allow grid connections to be restricted, either through direct steering / curtailment by DSOs or through limitations placed on maximum available capacity for a certain grid user and time period.

The most relevant category in this context are **alternative** or **conditional grid connections**[120] as mentioned within the revised directive 2024/1711 regards improving the European Union's electricity market design. There, the definition is specified to flexible connection agreements meaning "(…)

---

[119] The Netherlands had put in place a far-reaching framework for the prioritization of projects with social impact. However, this approach was rejected in court as of March 2025. See the deep dive in sub-section 3 of this chapter.

[120] CEER (2023): CEER Paper on Alternative Connection Agreements, self-published, available online: https://www.ceer.eu/publication/ceer-paper-on-alternative-connection-agreements/ (last view: 14/01/2025)

a set of agreed conditions for connecting electrical capacity to the grid that includes conditions to limit and control the electricity injection to and withdrawal from the transmission network or distribution network."[121] The terminology around this definition of flexible connection agreements is however not consolidated, references to alternative or conditional connections as umbrella concepts are also common. So far, implementation of these approaches appears to be different and largely driven by practical concerns for how to get them implemented quickly within national institutional and legal frameworks The majority of MS (15) have implemented some form of flexible connection agreement, with variations in the type and specific implementation – either already in operation (AT, BE, DE, FI, HR, HU, NL, PT, RO, SE) or currently being tested or prepared through legal acts (CZ, ES, FR, SI, SK) for future incorporation (see Appendix 1). However, many of the processes are new or being set up, limiting the empirical evidence on market take-up. While Article 6 of the Electricity Directive refers to conditional grid connections as both a temporary and a permanent measure, many of the current approaches are set up with time limits and appear to address specific issues rather than a strategic complement to the existing policy mix for the long-run. In some cases, grid operators are given the right to curtail or limit injections under specific conditions to maintain system stability, which can be either a substitute or a complement to conditional grid connections, depending on how the incentive structures are defined.

Currently, the agreements are **not always applied to the full market, but rather to larger contractors** with individual needs. Screening the available documents also reveals that the introduction of such agreements is not only technically complex but also comes with additional administrative and legal tasks. Examples include the modification of network codes (e.g. NL) and the development of bilateral contracts (e.g. AT). The agreements in FR can serve as a best practice of working this through by starting with a sandbox in 2022 to test the agreements. To ensure clarity and consistency, flexible connection agreements should specify key elements such as capacity limits for firm and flexible access, applicable network charges, and the duration of the agreement, along with the expected timeline for granting full firm capacity. Additionally, system users opting for a flexible connection are required to implement certified power control systems. Given the increasing relevance of these agreements for integrating renewable energy and e-mobility, ensuring compliance with the directive's framework will be key to achieving a structured and efficient electricity market.

Despite this common approach, key differences exist, encompassing both monetary incentives and administrative approaches. Some countries, such as DK, offer significant reductions in connection fees for users opting for non-firm capacity. In contrast, AT and SE provide flexible connections without financial compensation for curtailment. Another distinction is in the contractual design: NL has introduced capacity limitation contracts, with some providing fixed time windows and others operating on a day-ahead basis, ensuring financial compensation for restricted access. Meanwhile, DE follows a different approach by allowing DSOs to temporarily reduce the power consumption of flexible technologies (e.g., EV chargers and heat pumps) in exchange for reduced network tariffs.

To enhance performance, reduce delays, and create more transparent procedures, national-level interventions are increasingly considered to cope with increasing numbers for grid connection requests. DE serves as a prominent example of such an intervention through the introduction of § 14a of the Energy Industry Act (EnWG). This provision empowers DSOs to temporarily reduce the power consumption of certain flexible end-use technologies – such as electric vehicle chargers and heat pumps – during periods of grid congestion. In return, affected customers receive reduced network tariffs or financial compensation. The measure is intended to alleviate pressure on local distribution grids without requiring immediate infrastructure expansion, while simultaneously incentivizing consumer flexibility and enabling the integration of additional loads. Importantly, this regulatory framework also introduces standardized conditions and technical requirements, which are further detailed by the NRA. By clearly defining when and how curtailment can occur, § 14a EnWG aims to foster greater transparency, fairness, and efficiency in the handling of flexible loads - especially in view of the growing electrification of the heating and transport sectors. Such national-level approaches illustrate how targeted regulation can address structural challenges at the DSO

[121] Article 2 of Directive 2024/1711 amending Directives (EU) 2018/2001 and (EU) 2019/944 as regards improving the Union's electricity market design. Link: L_202401711EN.000101.fmx.xml

level and support the broader energy transition by unlocking grid capacity through demand-side flexibility.

Findings from interviews confirm that many countries already offer flexible connection agreements that allow customers to secure grid connections for assets with injection capacities exceeding current availability. In return, customers must sign an additional contract and accept the possibility of being limited in their usage based on prevailing grid conditions. From the DSO's perspective, this method is typically a temporary solution, as such agreements require a specific year to be designated when the originally agreed capacity can be utilized without restrictions. Additionally, a concrete project proposal must be presented to develop the necessary capacity (e.g. AT).

3. PROCESS OF GRID CONNECTION REQUESTS

To date, MS have very different **lead times** for processing connection requests. The typical deadline varies from a few business days (e.g. IT, EE, BE) to more than a year especially for larger projects in higher voltage levels requiring permits, environmental approvals or negotiations with municipalities (e.g. CY, DK). However, it should be noted that the above deadlines are not representative for all assets / connection types, as there are typically several different administrative procedures with distinctions by various forms of size or complexity of the respective request. Factors for making distinctions include grid level (e.g. AT), available local grid constraints, need for a connection plan (e.g. CZ) and for coordination with local authorities.

Most MS have some form of **simplified process for small assets** (e.g. AT, ES SI), but the definitions and thresholds vary widely. While some MS divide by grid levels, in many cases the distinction is by load. For households, even loads from typical commercial wallboxes can exceed what is deemed small (e.g. 11 kW as a threshold when 22 kW is not unusual nowadays). Progressions tend to be steep, escalating from business days for small projects to several months for larger projects (see e.g. EE). These streamlined procedures often incorporate digital processes and contracts that seek to alleviate administrative burdens for both customers and DSOs. Notably, there are nationwide standards set by NRAs for implementing these simplified processes for small assets, which all DSOs follow (e.g. AT).

While the spread appears arbitrary to some extent, the above factors also show that in many cases, there are **associated processes or stakeholders based on national particularities,** such as energy systems and requirements from federalism, which make it difficult to define a reasonable universal limit. Regarding the institutional levels, in several MS the deadlines are not fully specified with national requirements referring to a "timely" response but leaving the handling to the DSOs. Generally, the deadlines are sometimes directly specified within national energy laws, but in other cases within network codes, (binding or non-binding) NRA guidance documents, set even regionally or by service area. To improve the transparency over the process, selected practices include deadlines that reflect the complexity of the underlying procedure (e.g. HR), staggered deadlines for different steps of the process for better transparency (e.g. CZ, RO), short deadline at least for notification of next steps and expected costs (e.g. 6 days in LU).

In contrast to the stated lead times in national laws and regulations, there is an increasing number of MS that are dealing with queues that pose a risk to the timeliness of grid connections. Given the high level of fragmentation in the processes for different types of grid connection requests, the present study cannot quantify the additional time in excess of stated lead time systematically. The data shows in particular that queues currently arise for different reasons across the EU. Understanding these differences is important against the background of increasing volumes of grid connection requests across the EU.

Factors contributing to backlogs in grid connection requests include:

- Lack of capacity due to existing congestion (e.g. NL, HU)
- Low entry barriers to the process (e.g. IE), which can encourage speculative grid connections
- Missing incentives to prevent over-reservation of capacity in larger projects (recently reformed with tougher filtering criteria in SK)
- Complexity and ambiguity in processes (e.g. PL)

- Administrative delays from lack of organizational capacity and digitalization at small DSOs (e.g. DE)

- Constraints at transmission level spilling over into distribution level (e.g. DK, IE)

In several MS, the issues are asymmetric: queues tend to be more problematic on the generation than on the consumption side (e.g. in CY). In some MS, the issues are so far only local (e.g. DE, BE), while others expect issues and are changing grid connection processes in anticipation (e.g. IT). In some cases, queues happen only for certain grid user types that are new (e.g. storage, data centres). In effect, the above factors all hinder timely grid connection requests, but the list shows major differences in the underlying conditions and whether the queues hinge on accelerating grid reinforcements on the DSO side or could be tackled also by reforming the administrative processes or adopting conditional grid connections.[122]

This relates to the point of **streamlining of the connection process**. The procedures for handling connection request are not harmonized across the EU. Some MS are already offering services that would fulfil the ambition of the GAP (e.g. SI, ES), while others have not streamlined processes nationwide. In MS with multiple DSOs, there is often a common platform, but its functionality differs regarding the depth of unification. For example, in DE, there is a platform with harmonized information, but the request must be made with the DSOs. Several MS have a hybrid solution, where there is a streamlined national process coupled with the possibility for DSOs to deviate slightly in order to accommodate local situation (e.g. DK, CZ, SK). It is important to note that the simplification of processes through unification and streamlining affects customer experience and connection processes differently for various customer groups. Different DSOs may have distinct technical grid conditions and requirements for obtaining a connection. Standard small customers are unlikely to benefit significantly, as they typically undergo this process only once or twice for connecting a small-scale PV plant or wall box. In contrast, larger project companies that operate across multiple regions or internationally can gain more from these streamlined processes.

In MS with **multiple DSOs**, there is varying harmonization across DSOs, subject to national requirements or common practices that are not necessarily explicit from the law. Some MS have a uniform process with common forms (e.g. NL, ES) or at least a regionally uniform process (e.g. BE). In many cases, however, there are rather broad general requirements and then the actual process is specific to the DSO. The **policy situation is dynamic**, with many revisions and re-classifications in recent years. These appear to be linked to broader energy and climate policy revisions and not solely grid-oriented measures.

Regarding **digitalization**, there is a difference between electronic submission (e.g. online forms) and an interactive platform where the request can be filled directly, without reliance on downloads (e.g. PT). The former is currently the more common form of implementing digital processes. Few MS still have explicit processes for alternatives to the implemented digital solution, i.e. sending forms by letter or via phone (e.g. FR, BE). In countries with one large DSO and several smaller DSO (e.g. FR, IT, RO), the larger entities tend to have a platform solution, while smaller DSOs have different and heterogenous procedures that are operated in parallel. These procedures also affect the overall administrative burden. Several MS have simplified procedures for smaller users or for certain assets like small-scale PV (e.g. SI, SE), but the overall complexity differs on a case-by-case basis, as it also depends on whether other stakeholders have to be involved (e.g. project developers, installers, land owners). In this context, NL can be named as a possible best practice by implementing a platform that is shared also with other utilities providers (e.g. water) for economic efficiency.

5.3. Selected practices for deep dives

Following on the previous analysis of the overview of the temporal and administrative situation in the implementation of grid connection requests on the basis of the three design features, the following section provides deeper insights into selected topics. The previous analysis showed that the

[122] See also the recent report by Eurelectric (2025). From Backlog to Breakthrough: Managing Connection Queues in Distribution Networks. https://www.eurelectric.org/publications/from-backlog-to-breakthrough-managing-connection-queues-in-distribution-networks/

following **five priority themes** are of particular interest for reporting on challenges, best practices or possible future solutions in more detail:

> **1. Timeliness:** While most MS have national provisions related to timely grid connection processes, there is a wide range of actual deadlines and a lack of information on how those are operationalized, especially when DSOs have their own processes based on the national requirements. This raises the question whether timeliness can be more closely described and/or linked to actual administrative timelines and efforts while respecting real constraints from grid conditions and workload of DSOs.
>
> **2. Fragmentation:** Most MS have different requirements for different asset types, grid levels and a host of other distinction factors. There is an apparent trade-off between more fragmentation allowing for faster, leaner processes for small assets and an increase in complexity of the overall system. In addition, the rules for what is "small" are not harmonized and subject to frequent revision in some MS. Additional trade-offs emerge in provisions that assign priorities and have to be reconciled with non-discrimination. More insights are needed on how market segments can be clustered in light of these trade-offs.
>
> **3. Conditional connection agreements**: There are several novel approaches to deal with lack of capacity, with conditional grid connections gaining traction across Europe. More insights are needed on how these different agreements under the umbrella of alternative connections can contribute to shaping incentives: both for DSOs to accommodate new grid users and for the users' behaviour to be aligned with grid conditions. In this aspect, the third topic is closely linked to the second topic and these linkages should be explored. Special focus lies on the requirements given by the revised directive on energy markets, e.g. the provision of flexible connection contracts, and how these are already or will be implemented by the different member states.
>
> **4. Implementation constraints:** Securing timely and transparent treatment of grid connection requests require DSOs to adopt new processes, improve operations and take on new responsibilities. Evidence from MS with larger and smaller DSOs indicates that smaller DSOs have less resources to set-up new approaches resulting at least partly in implementation constraints. More information is needed on how these constraints affect the feasibility of working towards the adoption of selected practices in other geographical or organizational settings.
>
> **5. Capacity maps:** While some DSOs already use capacity maps within their DNDP and/or transparency platforms to highlight available grid capacity, it remains unclear to what extent these maps are frequently updated, in which geographical granularity and thereby whether facilitate the identification of available grid capacity for connection requests. In this context, it is important to explore how different design approaches—such as update frequency, data granularity, or integration into permitting processes—affect the effectiveness of these tools in network planning and investment decisions. Since capacity maps are also linked to alternative connection models and the fragmentation of connection processes, potential synergies and challenges in this area should be further examined.

Based on these priority themes together with the insights presented in 4.2, best practices and in-depth analyses for each subtopic within specific countries was selected and is presented below.

For the topic area of grid connection requests, we chose to organize the deep dives under the design categories used for data collection instead of the cross-cutting priority themes because the high level of fragmentation within the topic area is best streamlined with the categories that guided data collection. While some topics reveal similarities across the European landscape, others showcase distinct strategies for addressing challenges, particularly regarding measures to mitigate issues related to insufficient capacity (see point 2 on measures in case of lacking capacity below).

1. DETERMINATION OF GRID CONNECTION POTENTIAL

Estonia - connection capacity calculation app

Context: Estonia has a highly centralized distribution network structure with Elektrilevi as the sole DSO. Elektrilevi is responsible for operating, maintaining and expanding the entire medium- and low-voltage grid across the country. A clear division with the TSO Elering ensures that Elektrilevi handles networks up to 110 kV, while Elering manages the high- and extra-high-voltage levels. Under Estonia's national digitalization strategy, the rollout of smart meters is fully complete and a nationwide SCADA system provides real-time monitoring and automated control of large parts of the grid. This comprehensive digital infrastructure delivers high transparency and optimized operations.

Content: Elering offers its online GIS tool "e-Gridmap," an interactive platform where prospective grid users can retrieve preliminary information on current and potential capacities at selected 110 kV and 330 kV substations. The application provides annual capacity forecasts for the current year plus the next four years, with all future assumptions consolidated in the final forecast year. It also distinguishes between feed-in and feed-out potential. On a clear, map-based interface, lines and stations are displayed graphically, and available capacities are visualized via a colour scale that can be filtered by range. Clicking on any substation opens an information dialog showing the timestamp of the last data update as well as a cost estimate for the requested connection capacity. In addition to detailing the technical measures required, the tool breaks down the estimated investment costs according to a 120-minute versus a two-hour outage scenario. All detailed information can be exported as PDF or Excel reports. For binding capacity requests or further specifications, users are referred to the Elering Connection Information System.

Elektrilevi provides an interactive, GIS-based map of available capacities in the medium-voltage network. It visualizes unused resources based on current line loading and highlights which feeders can accommodate new connections without costly upgrades—supporting both consumers and generators in their site-selection process. The map classifies available feed-in capacity into four bands (200 kW, 500 kW, 1 000 kW and 2 000 kW); connections below 200 kW are not displayed, and users are directed to submit an individual request. Capacity calculations are voltage-level specific and take into account both in-service and pending connection commitments. Potential power exchanges with the transmission network and substation constraints are not considered. Clicking on a line segment reveals the timestamp of its last data refresh. The connection costs reflect the actual anticipated expenses, but a formal request is required for quotations and schedules. Even where free capacity is indicated, project-specific construction work may still be necessary.

Evaluation: At the transmission level, detailed data are readily available and very helpful for stakeholder operating on this level of the grid, but on the medium-voltage network the information is noticeably less comprehensive and granular. Although the exact methodology for calculating free capacity isn't fully transparent, larger consumers and generators do receive clear, upfront indications of available capacity—enough to serve as an initial planning guide. Small-scale users and producers, however, gain little to no value. Crucial details such as connection costs and lead times are provided only after a formal request, which limits the tool's usefulness to a select segment of the DSO's customer base.

Germany – Tool for checking grid connection request

Context: With roughly 900 DSOs, Germany has a comparatively high number, resulting in a highly fragmented landscape of small and medium-sized grid operators. These DSOs are primarily responsible for low- and medium-voltage networks and, in some cases, also oversee higher voltage levels. Most are municipally owned. Their familiarity with their own grid infrastructure, existing capacity reserves and expansion strategies varies significantly, reflecting each region's historical grid development and past challenges. Although grids generally hold some reserve capacity, it tends to be lower for feed-in than for consumer supply.

Content: SNAP (Smart Network Analysis Platform) is a GIS-based planning and analysis tool from MITNETZ STROM that addresses distribution-grid challenges in the medium- and low-voltage range. Tailored for planners of medium-voltage feed-in systems (135 kW to 10 MW), it integrates grid data, simulations and monitoring functions into an intuitive interface. A free version and a paid "Pro" edition—with additional features—are available, and a user manual covers the core functionalities.

With SNAP, it is possible to verify quickly whether a proposed connection load can be fed into the grid. Therefore, it only needs the project address and required power, and the platform automatically identifies the nearest connection point and calculates the shortest route. Advanced filters let you preselect locations and display available grid capacity across the MITNETZ STROM network. In the interactive, web-based map mode, the user can explore suitable sites via aerial imagery and cadastral parcels, filtering by feed-in capacity and project scope. SNAP also generates automatic route proposals with preliminary cost indications, which you can then customize. An integrated project management feature helps the user organize and track all their planning data. When the user is ready, the tool can seamlessly transfer the preliminary network design to the formal network-connection check, ensuring a transparent, efficient and reliable planning process. Results of SNAP provide non-binding daily estimates and does not constitute a legally binding entitlement to a grid connection. Feed-in capacities are reserved once a project reaches a defined level of maturity.

Evaluation: The platform SNAP equips feed-in customers with a unified decision-making tool by presenting available grid capacities alongside price indicators. However, it does not provide a clear timeline for connecting to the grid. As an all-in-one solution directly integrated with DSO services, it comes in both free and commercial editions, allowing users to choose functions and data access in a needs-driven, cost-effective way. The methodology behind capacity and cost calculations remains opaque, making it difficult to judge the reliability of the results. Although detailed data are generally available at the medium-voltage level, it is uncertain whether the same method can be applied to low-voltage networks. Currently, the tool is aimed exclusively at feed-in customers rather than end consumers. In principle, however, its core capabilities could be transferred to other DSOs or MS and their grids, provided sufficient data are available.

2. MEASURES IN CASE OF LACKING CAPACITY

Croatia - Investor agrees to connection before creation of technical conditions

Context: Croatia's electricity distribution network is shaped by significant regional disparities in infrastructure, electricity demand, and technological development, reflecting the country's diverse geography. To manage these differences, the distribution system operator is organized into multiple local areas and regional groups, enabling tailored network management according to specific regional needs.

Content: New rules have been introduced to govern grid connections for energy producers and storage operators, including a preliminary connection process. Under this framework, investors may agree to connect before the necessary technical conditions are fully in place. In such cases, an addendum to the connection contract specifies the operational restrictions applicable during the interim period. The updated procedure also includes simplified steps for smaller-scale installations, easing their integration into the distribution network.

Evaluation: This model offers greater flexibility for developers, particularly in regions with constrained grid infrastructure, by allowing project timelines to advance while technical upgrades are still pending. It can help accelerate renewable deployment and encourage early-stage investment. However, it also shifts some operational risks to the investor, who must manage output restrictions until full grid readiness is achieved. Replicating this approach in other EU countries may depend on legal clarity, the strength of regulatory oversight, and the ability of DSOs to coordinate interim technical limitations effectively. While promising for project acceleration, such arrangements require careful contractual design to ensure grid stability and investor confidence.

Netherlands – First come first serve with predetermined priority framework

Context: The Netherlands operates a primarily centralized electricity distribution structure, with a few large DSOs. Grid connection requests have historically been handled on a first-come, first-served basis. However, persistent and growing grid congestion – especially during peak hours – has led to increasingly long waiting lists for new connections. A major driver of this congestion is the rapid expansion of renewable energy capacity, particularly solar PV. In fact, the Netherlands became the world leader in solar PV share in electricity generation in 2022, with PV accounting for 36% of electricity produced. This rapid growth placed significant strain on grid infrastructure that was not built to accommodate such fast-paced decentralised generation. In response, a shift toward more flexible grid management has emerged. Since 2024, Dutch system operators have been empowered to apply a formal prioritization framework in congested areas. This framework is intended to make more effective use of existing grid capacity and ensure timely connection of socially critical infrastructure.

Content: The new prioritization framework, introduced by the Netherlands Authority for Consumers and Markets (ACM), allows DSOs to rank connection requests based on societal value rather than processing them strictly in order of application. This system introduces three priority tiers. First, so-called "congestion softeners" – such as battery storage or flexible assets that alleviate grid pressure – are prioritized. Second, infrastructure tied to public safety and emergency response, including defence and healthcare, receives precedence. Third, basic public services, like drinking water supply and schools, are considered. The framework is based on transparent, objective criteria, developed through broad consultations involving system operators, municipalities, provinces, and the Ministry of Economic Affairs and Climate Policy.

Evaluation: The prioritization framework marks a significant evolution from the rigid first-come, first-served model, allowing the Dutch grid to better accommodate essential public services during periods of severe congestion. It introduces much-needed flexibility, enhances resilience in the face of limited capacity, and aligns grid access with broader societal priorities. The system also integrates demand-side flexibility incentives to optimize existing infrastructure.

In March 2025, the Dutch Trade and Industry Appeals Tribunal (CBb) ruled that while the Netherlands Authority for Consumers and Markets (ACM) is legally authorized to introduce prioritization, it must provide a more thorough justification for the selection criteria used.[123] The court stressed the importance of a clearer rationale and greater transparency in determining which projects qualify for priority access, with stakeholders urging the inclusion of additional socially vital services such as telecommunications, public transport, and waste management. ACM has been instructed to revise the framework by January 2026, though the current version remains in effect until then. To ensure system operators can continue prioritizing projects that serve major social objectives, ACM plans to publish a new draft decision on the prioritization framework by late June 2025 and is inviting all stakeholders to respond within six weeks.

The Dutch approach could serve as a model for other Member States facing similar grid congestion challenges. Its structured prioritization framework enables a more strategic allocation of limited grid capacity, supported by strong stakeholder collaboration and demand-side flexibility measures that help alleviate congestion without immediate grid upgrades. However, challenges remain. The approach requires rigorous legal justification and transparent criteria to avoid perceptions of unfairness. Moving away from a simple first-come, first-served system introduces administrative complexity that may slow decision-making if not well managed. For wider adoption, ensuring non-discrimination, legal clarity, and public trust will be crucial. Still, the Dutch experience shows that combining targeted prioritization with flexibility incentives can offer a scalable solution for managing constrained grid capacity.

Hungary – Pro-rata vs Tender-based procedure

Context: Hungary has seen a rapid expansion of photovoltaic energy, leading to near-saturation of the public grid and prompting the government to suspend key application regimes in 2021 and 2024. The grid has struggled to keep up with the pace of solar development, compounded by speculative applications and cancelled projects. In response, a new connection regime is being introduced to better manage capacity through standardised procedures and financial guarantees, ensuring only serious developers gain access.

Hungary's renewables market is dominated by PV, accounting for nearly 88% of capacity. The National Energy and Climate Action Plan targets 29% renewables by 2030, with 90% of the planned 13.4 GW to come from solar. While past support schemes like KÁT and METÁR fuelled growth, many developers are now shifting toward market-based models due to reduced subsidies and high electricity prices. Storage-related support mechanisms may still play a significant role moving forward.

---

[123] See the release on the ruling here: https://www.acm.nl/en/publications/response-cbb-ruling-acm-has-independent-power-set-prioritization-framework-and-make-choices

Content: Under the new system, Hungary will allocate available grid connection capacity for producers at medium and high voltage levels through competitive national-level tenders, held at least biennially. These will be overseen by a five-member evaluation committee, with applications assessed based on a scoring system defined in the Proposal and specific tender notices. Preference will be given to projects that include above-minimum battery storage, hybrid integration, stronger financial guarantees, and lower environmental impact. Recultivation obligations after decommissioning also factor into the evaluation.

The Hungarian Energy and Public Utility Regulatory Authority (HEA) will administer the tenders upon request from the Ministry of Energy. Tender notices will specify available capacities by node and technology, connection timelines, required fees, and any additional obligations like storage. Applicants must submit bid guarantees, and winning bidders will need to provide performance guarantees as well. Limits on multiple bids from related entities and partial award declarations aim to prevent strategic overapplication. The first tender round is expected in 2025, with results anticipated by year-end.

Evaluation: While the framework introduces much-needed structure, several uncertainties remain – particularly around the details of financial guarantees, scoring metrics, and the appeals process. These will be clarified in each tender notice. The HEA plans to hold consultations to help applicants align with procedural and technical requirements, potentially improving bid quality and reducing disputes. Nevertheless, the success of the new regime will depend on its transparency, enforceability, and whether it truly balances fairness with system efficiency.

From a broader European perspective, Hungary's transition to a structured, competitive tender-based allocation model could serve as a reference point for other Member States facing similar issues of grid saturation and speculative applications or lower voltage levels. The model offers clear advantages, such as improved transparency, strategic alignment with system needs (e.g. hybridisation or storage), and better filtering of unserious applicants through financial guarantees. However, potential drawbacks include the risk of high administrative complexity, the exclusion of smaller market actors who cannot meet financial thresholds, and reduced flexibility in rapidly changing market conditions. To be successfully implemented elsewhere, such a system would require careful adaptation to national legal frameworks, grid planning practices, and the maturity of local renewable energy markets.

Poland – Planned auction of available capacity

Context: Poland's energy system remains heavily reliant on fossil fuels, particularly coal, which still dominates electricity generation and results in high CO_2 intensity compared to other countries. While coal's role has gradually declined, recent years saw a resurgence in demand, highlighting the difficulty of rapid transition. Nevertheless, Poland has made notable strides toward renewables. Offshore wind development is also progressing, and the updated National Energy and Climate Plan (NECP) targets a doubling of renewable energy consumption by 2030.

This rapid growth in renewables has exposed serious limitations in the electricity grid. Much of Poland's grid infrastructure is outdated, with a large share of transmission and distribution lines exceeding 40 years in age. As a result, connection refusals have skyrocketed, with over 80 GW of rejected applications in 2023. In response, the Polish government introduced a comprehensive Energy Law reform in 2025, including capacity-based application fees and a shift toward auctioning available connection slots. These changes aim to reduce speculative applications and improve planning in the face of growing congestion and rising investor demand.

Content: As many countries struggle with long queues for grid connections due to high volumes of applications, Poland is taking a proactive step by introducing auctions for available grid connection capacity of the transmission grid and high-voltage distribution networks (110 kV). This mechanism is designed to enhance efficiency and transparency in the allocation process, helping to avoid bottlenecks in the future. While maintaining the principle of equal treatment is essential, there are valid concerns about the high rejection rate of applications. To ensure fairness, it is crucial that the auction framework is inclusive and incorporates quality-based criteria, preventing smaller or less-resourced participants from being disadvantaged.

To further improve the allocation of grid capacity, recent legislative amendments in Poland establish mandatory auctions for released capacities. When a grid connection agreement is terminated – typically due to a project's failure to meet certain milestones – the transmission or distribution system operator must initiate an online auction. This process allows other entities to bid for the same grid connection point under equivalent technical conditions. Interested participants must submit their applications via an electronic platform, provide a financial deposit proportional to the requested capacity, and agree to the terms of the auction.

The auctions run for eight hours, with bids submitted in increments of at least 100 PLN per megawatt (MW). The highest bidder secures the right to sign a new grid connection agreement, provided payment is made within 14 days. If the winning bidder defaults, the auction is repeated. Proceeds from the auctions are used exclusively for maintaining and expanding the electricity grid and are excluded from tariff calculations. To ensure accountability, the rules governing these auctions must undergo public consultation and be approved by the national energy regulator. Additionally, system operators are required to report annually on auction outcomes. This auction-based model aims to allocate capacity competitively, plan grid development strategically – such as in designated renewable energy zones – and reduce the risk of speculative grid access reservations.

Evaluation: The Polish model of connection capacity auctions could offer a transferable approach for other EU Member States struggling with grid saturation and speculative connection requests. By introducing competitive allocation, it can enhance transparency, encourage serious applicants, and align grid use with broader energy planning. However, successful transfer would require tailored design to account for national regulatory frameworks, grid conditions, and market structures. A key advantage lies in its ability to pre-empt speculative hoarding and enable prioritization without explicit legal ranking of sectors. On the downside, if not carefully calibrated, auctions may unintentionally favour larger, well-resourced developers and undermine inclusiveness or innovation – particularly in countries with a more diverse or decentralized renewable energy landscape. Therefore, ensuring broad stakeholder engagement and embedding safeguards for smaller actors would be crucial for broader adoption.

3. TRANSPARENT PROCESS OF GRID CONNECTION REQUESTS

Estonia – One-stop-shop

Context: In Estonia, a single, centralized DSO Elektrilevi manages both the low- and medium-voltage networks, a setup that stands in contrast to the fragmentation found in many other countries. Tariffs and connection conditions are approved by the Estonian Competition Authority (Konkurentsiamet), creating a binding regulatory framework. Standardized procedures for grid connections, technical inspections and the nationwide smart-meter rollout ensure high transparency and efficiency. Under the mandatory connection obligation, Elektrilevi must accept every applicant once the technical requirements are met.

Content: Estonia leverages its advanced digital infrastructure to provide a fully online procedure for both new grid-connection applications and modifications to existing connections. Through a single e-Service portal, the DSO acts as a one-stop shop, allowing users to complete every step digitally without visiting the DSO’s office in person. The platform features a dashboard with real-time outage information and maps, as well as a GIS-based module that estimates available medium-voltage line capacities.

Connection requests follow a guided workflow: after logging in, applicants specify the connection type and key information like address or required capacity. Additionally, there is an option for upload any additional, non-standard documents. Acceptance of the general connection terms issues a case number whose status is visible at any time. Within ten working days, the request is reviewed in line with the Konkurentsiamet requirements. A binding offer—complete with technical specifications, itemized cost estimates, and project timeline—is delivered no later than 30 working days after submission. Once the agreement is signed and a deposit paid, construction works commence. Progress is tracked digitally, triggering automatic notifications. Upon successful commissioning, the platform issues the final invoice. All processes, data provisions, and deadlines strictly adhere to Konkurentsiamet regulations.

Evaluation: Estonia benefits from a One-DSO model, as coordination is required only between the NRA and a single DSO. Standardized procedures, binding deadlines and clear regulatory frameworks enable rapid connection times. Combined with a high level of digitalization, this ensures transparent processing of grid-connection requests, with coordination with the TSO clearly defined and systematically integrated into the workflow. Customers always know exactly whom to contact, even if certain details are only provided at later stages of the process. Due to a lack of robust data, actual compliance with deadlines cannot currently be assessed. The requirement for digital identity verification during application is unproblematic in Estonia but could pose challenges since the use of an official digital ID is not yet widespread in some MS. Moreover, implementing a similar solution requires comprehensive regulatory guidelines to ensure a highly efficient and user-friendly process, especially in highly fragmented MS.

France – Online platform with different procedures depending on customer group

Context: France's electricity distribution network operates under a centralized concession system. Enedis—a near-monopoly—manages roughly 95 % of the public distribution grid, while some 150 small municipal or inter-municipal operators cover the remaining 5 %. The CRE supervises all operators, approves long-term concession contracts and issues standardized tariffs and connection terms. From connecting new customers or producers to rolling out smart meters, almost every process follows a nationwide, legally binding catalogue of grid-connection requirements, fee schedules and technical standards.

Content: Enedis provides the "Service Raccordement Électricité" platform as a centralized, form-based entry point for all grid-connection requests. An integrated selection tool guides applicants to the appropriate connection type—whether for residential customers, commercial clients or renewable-energy producers. Standardized forms capture all relevant data, including address, connection type, capacity, desired deadlines and the proposed transformer location. Direct contact with an Enedis expert can be established at any stage to clarify questions or details.

Submitted applications are reviewed by Enedis specialists, who address any follow-up queries before forwarding completed dossiers to the relevant internal departments. A cost estimate is issued within two to six weeks. Once the deposit is paid, connection works commence and are generally completed within six to eighteen weeks, depending on the distance to the distribution network and required capacity. Final commissioning follows one to two weeks after settlement of the remaining balance. An integrated estimation tool provides preliminary time and cost forecasts during the application phase, refining accuracy as the project advances.

Residential connections up to 36 kVA follow a simplified procedure, while commercial clients and renewable-energy operators must use the S3REnR process. This method relies on a forward-looking assessment of future network needs to ensure smooth integration of the expected feed-in capacity. In addition to general application data, producers must submit a feasibility study, an electrical compliance certificate and a preliminary connection agreement. Commercial clients are also required to provide details on protection measures and, where applicable, approvals from local authorities.

Evaluation: Enedis's "Service Raccordement Électricité" platform stands out as a genuine all-in-one solution: it serves as the single point of contact for all grid-connection requests and securely guides applicants to the appropriate connection type via standardized forms. A documented review by Enedis experts, combined with the option for personal consultation, ensures high functionality and user friendliness. Immediately after entering the basic project data, an integrated tool provides initial rough estimates of both time requirements and costs—enhancing user communication and significantly boosting overall transparency. The entire process complies with the mandatory regulations of the French grid regulator CRE, as evidenced by clear deadlines and established communication channels. The ability to view application status online at any time further reinforces transparency. However, the reliability of these projections remains limited, since no details on the data was available. In principle, this platform can also be adapted to other DSOs in other MS—particularly when a DSO has sufficient scale and resources to host such a system and when uniform regulatory requirements exist that can be fully implemented within a single platform.

6. RECOMMENDATIONS

The following section presents recommendations drawn from the data collected and analysed throughout the previous sections. These recommendations serve two interconnected purposes.

First, the recommendations identify where and how EU action can be taken to advance distribution networks across the EU-27. The recommendations are thus intended to feed into the ongoing streams of policy work at the EU level, including tasks covered by supranational institutions in line with the key actors called upon in the Grid Action Plan.

Second, the recommendations draw on the findings that emerge from the MS heterogeneity to provide learnings from current practices that can be shared among MS' legislators and regulators to improve the functioning of distribution networks towards readiness for the future energy system.

To serve both of these purposes, the recommendations draw on the selected practices in the MS and their analysis with the aim of informing action from a European perspective. Therefore, the synthesis of the findings from the deep dive analysis per topic area is a primary source for formulating recommendations. This encompasses an evaluation of the adaptability of identified best practices to other MS contexts. In addition, compliance and policy gaps receive dedicated attention. Compliance gaps in this sense include gaps regarding implementation of EU legislation, while policy gaps refer to needs for elaboration/adjustment in regulation and/or legislation.

The recommendations are **structured by sub-topic**. Within a sub-topic, each recommendation is followed by an explanation regarding the following:

a) Design feature(s) the recommendation pertains to.

b) Type of action (e.g. legislative/regulatory action, communication or sharing of best practices, study to conduct).

c) Level of action (e.g. EU, MS, DSO/NRA)

It is understood that not all recommendations map cleanly onto a single item, action, or level. Interdependencies and gaps in responsibilities are noted accordingly.

6.1. Network development planning

SUBTOPIC 1: Regulatory regimes and practices for the design and implementation of DNDPs

Improve transparency and accessibility of DNDPs by enforcing full public publication and encouraging English summaries.

DNDPs are published publicly in most MS except three. Public publication increases transparency and accessibility of DNDPs, informing stakeholders, facilitating an informed dialogue and allowing for the sharing of best practices.

To tackle this, action at the EU level should consider mandating public availability by EU legislation. While the Electricity Directive requests publication of DNDPs, the (Proposed) Network Code on Demand Response is more explicit in terms of public publication. In particular, the terminology used in (Proposed) Network Code on Demand Response Article 43 (2 and 6) seems suitable (e.g. "*make publicly available*" and "*shall be published on the DSO's website and on a central publication and communication platform*"). This terminology could be taken over by the EC in the finalization and adoption of the (Proposed) Network Code on Demand Response. We recommend that the EC also shares the best practice to publish all DNDPs in one place online (e.g. www.vnbdigital.de in Germany, hosted by the DSOs themselves) with MS with multiple DSOs.

Furthermore, in most MS DNDPs are only provided in the national language, which limits transparency, especially for international citizens but also for international market participants, and opportunities for cross-border learning. Still, it is important to also consider that developing full DNDPs in English could present an administrative burden to DSOs, while the largest share of readers are likely domestic readers. Hence, encouraging DSOs to provide summaries of DNDPs' key insights could be a pragmatic compromise that balances transparency with administrative burden. (Examples of such key insights could be: scenario basis, flexibility usage, actionability of DNDP (including a high-level overview of investments and capacity additions, etc.).

Public publication as well as availability of information in English relate to the design category **Technicalities of DNDPs**.

Harmonise DNDPs between DSOs within each Member State by developing a common reporting structure.

In MS with multiple DSOs, the lack of coordination and common structure between DNDPs leads to inconsistent reporting and hinders comparability. In 15 of the 19 MS with more than one DSO[124], some form of common structure is available, either by a template, by listing required content in national legislation, or by guidance listed by the NRA. However, often still gaps remain in ensuring the comparability and completeness of the DNDPs.

To address this, the required content elements and the document structure should be more clearly defined. National legislation or the NRA should define requirements on what content elements DNDPs must include. This should cover both the basis and procedure (e.g. scenario assumptions, methodology, treatment of flexibility) and the expected outputs (e.g. investment lists, capacity maps and expansion needs). Germany provides a good example of such a list of content requirements, as elaborated on in Section 3.3. Then, DSOs should be encouraged to jointly develop a common document structure to ensure consistency in how the required content is presented. This could be facilitated through national DSO associations or working groups. In MS with no harmonisation and no indication of a proactive harmonisation between the DSOs, the NRA should align with the national government on providing a common structure, either by clear requirements as part of the next revision of the respective national law, or by a guidance shared by the NRA.

In this way, inclusion of all relevant information in the DNDP can be safeguarded, and comparability can be improved. This addresses the design category **harmonisation within a MS between DSOs**.

Increase the actionability of DNDPs by enforcing inclusion of detailed investment plans and requesting the development of capacity maps, considering results of the DNDP in terms of network development.

Several DNDPs lack sufficient detail to guide investment decisions or inform stakeholders, leading to a low **actionability of the DNDP**. Investment lists and capacity maps are explicit examples of elements that make the DNDP actionable and can directly inform stakeholders.

The Electricity Directive (Art. 32 (3)) already includes the requirement to set out planned investments for the next five to ten years, hence a compliance gap is present in the MS where the setting out of planned investments does not yet happen. NRAs should enforce the inclusion of investment lists to the DNDPs, for example during the consultation / approval process.

The analysis of all 27 MS has shown that in 19 MS investment lists / plans are available, albeit with varying levels of detail (i.e. in terms of voltage levels covered by the plan and list). Sharing of best practices across DSOs (e.g. German legislation and advanced lists of individual German DSOs) on the EU level could improve the degrees of actionability that such investment lists can lead to.

In contrast to the requirement to include information on investments, no legal obligation for capacity maps is currently applicable (or proposed). Requiring their development by EU legislation and including them or referring to them in DNDPs could therefore increase their actionability. As a consequence, stakeholders will be better informed on available capacity of the distribution (and transmission) network, and feeding into their own (investment) decisions accordingly.

[124] MS with one DSO accounting for >95% of connections, are in this perspective also considered as 'MS with one DSO'.

Currently, in 22 MS capacity maps are available. However, these maps are not uniformly standardized across DSO(s) or TSO(s) within a MS, and even less so across different MS. Ongoing efforts to collect and harmonize capacity-mapping practices on a European level are thus important to improve grid planning in the medium-run (see **Infobox 5** in light of Action 6 of the GAP). This is also relevant in view of Topic 3 (Timely and transparent treatment of grid connection requests) and elaborated there further with an additional perspective on the grid user side.

For the investment lists and capacity maps, but also for the coverage of the DNDP scope in general, the considered voltage levels are heterogeneously treated across the MS. Tackling this point, the EC should evaluate the requirement which voltage levels be considered in DNDPs. In practice, the procedures vary strongly between the pure coverage of the high voltage grid (e.g. Hungary), the requirement to include high and medium voltage levels (e.g. Germany), and a full coverage of all voltage levels incl. low voltage investments (e.g. Portugal). Covering only the high-voltage grid in the DNDP does not ensure appropriate network planning for the challenges of a fast-changing electricity system. However, further research is needed to make a conscious decision if the low voltage grid level should also be covered by the DNDPs. A too high planning effort, less easily accessible DNDPs and fast permitting and implementation times for low voltage grid expansion could be significant reasons to limit DNDPs to the medium and high-voltage level.

SUBTOPIC 2: Procedural steps, data collection and governance of DNDPs

Ensure public consultation is conducted by enforcing legislation, recommending a suitable minimum duration, and facilitating engagement.

Public consultation of the DNDP is a key mechanism for **stakeholder engagement**, but it is not conducted in all MS and durations of the consultation vary. In MS where such public consultation does not occur, a compliance gap with Electricity Directive Art. 32 (4) is present.

MS / NRAs should enforce the organization of a public consultation process by the DSOs. Furthermore, a suitable minimum duration of this process (e.g. four to six weeks) should be agreed on and included in legislation (and enforced). The (Proposed) Network Code on Demand Response Art. 43 (2), which mentions a minimum time of six weeks, provides a suitable way to adopt this.

In addition, the way of conducting the public consultation should be organised in such a way that it can facilitate high levels of engagement and broad participation from all relevant stakeholders. Here, Finland can be taken as best practice example, where public consultations via innovative, interactive and transparent online platforms have achieved high participation rates.

Ensure results of the public consultation are submitted to the NRA and published publicly by obligating it in legislation and enforcing it.

While DSOs in all MS submit their DNDPs to the NRA, not all submissions include the results of a public consultation (if conducted), limiting transparency in terms of stakeholder involvement. This relates to the design categories **governance structure** and **stakeholder engagement**.

Electricity Directive Art. 32 (4) as well as (Proposed) Network Code on Demand Response Art. 43 (3) already require the submission of responses to the public consultation to the NRA. Hence in MS where this does not occur yet a compliance gap is present, which should be resolved by MS / NRA enforcement. In addition, public publication of the consultation results would be even better in terms of transparency on stakeholder engagement. This is requested in the (Proposed) Network Code on Demand Response Art. 43 (2).

Strengthen coordination between DSOs and TSOs in scenario development and network planning, including on timelines.

Lack of coordination and alignment between DSOs and TSO(s) can lead to inefficiencies in terms of network planning. In order to plan the distribution and transmission networks in a combined optimal way, coordination and alignment of network plans (and scenarios that feed into these plans) is important. This relates to the design category **TSO alignment and exchange**.

While in several MS (18) some form of TSO - DSO coordination does take place (albeit in different degrees), a deeper form of coordination and alignment would be valuable (e.g. in terms of applied scenarios, i.e. expectations of load and generation capacities and their regionalisation). Such deeper form of coordination and alignment should be embedded in EU / national legislation, for which the (Proposed) Network Code on Demand Response provides good starting points, e.g. Art. 43 (1bii) that requests coordination of scenarios between DSOs and TSOs and Art. 43 (5) that requests coordination of development plans between DSOs and TSOs.

Apart from legislative actions to improve DSO – TSO coordination, TSO(s) and DSO(s) could establish combined working groups to enhance coordination as well. Alignment on scenario assumptions is specifically important and relates with the design category **scenario building and forecasting** (within subtopic 3). The next recommendation further elaborates on this.

An element that is especially complex, yet paramount, in terms of scenario alignment between DSOs and TSO(s) is on the usage of flexibility (relating to design categories **flexibility forecasting** and **kind of proposed measures** within subtopic 3). Assumptions on the availability of flexibility in the system (storage, flexible loads, steerable generation) play a crucial role for the network development planning on the distribution and transmission level. Existing and expected flexibility services can be used for both distribution grid congestion management as well as transmission grid needs (congestion management and system balance management). Coordination on how these flexible capacities can and should be used across the grid levels is required to ensure that the flexibility of the system is not assumed to fulfil DSO and TSO services at the same time. While it is challenging to beforehand align explicitly on usage of flexibility services, a good starting point would be to be aware of what assumptions the other party takes. We recommend further sharing of best practices across DSOs and TSOs on this topic.

Lastly, alignment in terms of timeline of reporting between TSO(s) and DSOs is also an important element of coordination. Misaligned planning cycles between DSOs and TSOs can lead to inconsistencies in scenario assumptions, delayed data exchanges, and suboptimal investment decisions. To address this, MS should establish a synchronised planning schedule that ensures key milestones (such as scenario development, data submission, and draft plan publication) are aligned across TSOs and DSOs. A good practice is the German model, where regional scenarios are submitted ten months before DNDP deadlines, allowing for sufficient alignment. Hence, national legislation or regulatory guidance should define minimum coordination checkpoints and timelines.

While scenario development can be taken up in collaboration at the same time between DSOs and TSO(s), assumptions in terms of expected grid developments (for DSO as well as TSO level) are outputs of the eventual network development plans. Hence, they cannot feed into each other's plans directly and some form of delay is likely to be present. One way to cope with this could be to schedule development and publication of DSO and TSO plans in subsequent years (in MS where they are published biannually).

SUBTOPIC 3: Integration of renewables, development of charging stations and electrification of heating and cooling of buildings

Promote the alignment of scenarios and establishment of working groups on scenario development, including DSOs and TSO(s).

While DSOs in most MS use scenarios in some form in their DNDPs, the basis of the scenarios, number of scenarios and ways of using scenarios are very heterogeneous. A best practice would be for DSOs to align on scenario assumptions and methodologies (ideally including alignment with TSO(s) as well). This relates to the design category **scenario building and forecasting**, and also to design categories **harmonization within a MS across DSOs** (subtopic 1), and **exchange and Alignment with TSOs** (subtopic 2).

One way to organize such alignment could be through collective working groups, for example established via national industry associations. The Netherlands provides a best practice example here, where the industry association of system operators (Netbeheer Nederland) has a Taskforce on scenario alignment, in which DSOs and the TSO participate. Germany provides another best practice example, where alignment between DSOs (in each planning region) and the relevant TSOs in terms of scenario development takes place by the linking of DSO and TSO scenarios. To allow for consideration of unique grid conditions of specific DSOs, it is important to find a right balance between harmonization and some form of heterogeneity that provides more flexibility to include local conditions. Potential best practice procedures for developing a balanced alignment should be shared between DSOs. The EU DSO Entity could provide a suitable platform for this.

Consider grid enhancing technologies (e.g. dynamic line rating) as measure to be deployed instead of / next to grid development and report on their usage in DNDP.

To optimise the use of existing infrastructure, DSOs should systematically assess and report on the potential deployment of grid-enhancing technologies such as dynamic line rating, on-load tap changers, and digital monitoring systems. While in most MS DNDPs do not mention or regard such grid enhancing technologies, they can offer cost-effective and timely solutions to alleviate congestion, defer reinforcements, and increase hosting capacity. This relates to the design category of **kind of proposed measures**.

National legislation or regulatory guidance should require DSOs to explicitly consider grid enhancing technologies as part of their considered measures for network planning. For example, DNDPs could include a dedicated section on these technologies, outlining their expected impact, deployment status, and comparison (or interaction) with other measures.

Encourage inclusion of flexibility forecasting and flexibility use as measure in DNDPs by requiring assessment and reporting of flexibility needs and potential.

Flexibility is a key alternative to grid reinforcement, but is often not explicitly assessed or reported on in DNDPs. Electricity Directive (Art. 32 (3)) already requests for the provision of transparency on future needed flexibility services and for the inclusion of "*the use of demand response, energy efficiency, energy storage facilities or other resources […] as an alternative to system expansion*", addressing the design categories **flexibility forecasting** and **kind of proposed measures**. However, in many MS this does not happen (yet), leading to a compliance gap.

The (Proposed) Network Code on Demand Response plans to further specify this reporting obligation by requiring an explicit assessment of the need and procurement of flexibility services (Art. 29 (1)), which also needs to be reported on or directed to in the DNDP (Art. 44 (2, 3)), and which need to be considered as alternative measure to grid reinforcements (Art. 44 (1)).

Hence, in terms of legislative action no further additions are needed. Instead, NRAs should monitor and enforce the inclusion of flexibility forecasts and flexibility measures as required by current (and proposed) legislation, which they can support by providing further guidance on the flexibility assessment methodologies and by asking for explicit changes of the DNDPs during the consultation / approval processes. In addition, DSOs should share best practices in terms of such methodologies to help each other modelling and leveraging flexibility services.

SYNTHESIS: Elements of advanced DNDPs

For the topic area of network development planning, the question of what should be captured in a fully developed DNDP is a recurring question that also drives the above recommendations. To close out the recommendations for this topic area, **Table 9** therefore summarises the elements identified through this study (next page).

Table 9: Exemplary elements per Design Category considering what an 'Advanced DNDP' entail. (Note that several of these elements are already part of European legislation)

Key design categories	Exemplary ways of integration in 'Advanced DNDP'
Subtopic 1. Regulatory regimes and practices for the design and implementation of DNDPs	
Update Frequency of DNDPs	• Annual / Biennial (already fulfilled in all MS)
Technicalities of DNDPs	• Publicly available • Ideally a full English version available next to native language(s), otherwise at least key summaries in English available
Harmonization within a Member State across DSOs	• Use of common structure (that is provided by MS / NRA) • Developing shared set of scenarios together with all DSOs (and TSO(s)) in the MS
Minimum requirements for DSOs to develop a DNDP	N/a (No obligation for MS to introduce exemption possibility, this is an optional part of the legislation)
Actionability of DNDPs	• Detailed investment lists provided • DNDPs show or provide link to online version of capacity maps
Subtopic 2. Procedural steps, data collection and governance of DNDPs	
Administrative and regulatory procedure	• Embeddedness of DNDP development in national legislation, including guidance on contents, structure and procedure
Governance Structure	• Submission to regulatory authority of DNDP including responses to the public consultation
Stakeholder Engagement	• Organise a public consultation process • Ensure the period of the consultation lasts for a suitable period of time (e.g. 4 - 6 weeks) • Publicly publish the results of the consultation (including responses by the DSO)
Exchange and Alignment with TSOs	• Developing shared set of scenarios together with TSO • Aligning DNDP with the TSO network development plan in terms of content and timeline
Subtopic 3. The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings	
Scenario Building and Forecasting	• Alignment of scenarios between DSOs and TSO(s) (also see Design Categories 'TSO alignment and exchange' and 'Harmonisation within a MS between DSOs')
Flexibility Forecasting	• Inclusion of expected needs for flexibility services and potential use of flexibility forecasts in DNDP
Kind of Measures Proposed as a Result of DNDPs	• Similar to Design Category above - flexibility forecasting key element to allow for integration, as an assessment of the need and potential use of flexibility is the starting point for eventual adoption as a measure • Reporting on grid enhancing technologies as a measure to be deployed instead / next to grid development

6.2. Network tariff regimes and regulatory incentives

SUBTOPIC 1: Network tariff regimes

Preliminary considerations: Network tariffs provide the main contribution to cover network costs, but at the same time set incentives for the usage of the network and of electricity in general. In light of this background, the network tariff regimes must fulfil several requirements to support an efficient grid and energy system. One key requirement to consider is the level of grid costs as part of electricity costs compared to other energy carriers to avoid dis-incentives for decarbonization through relative energy prices. This is crucial as electrification, e.g. of the heat and transport sectors, are important strategies for the decarbonization of these sectors. If utilization of existing grid capacities increases, typically only minor additional costs occur (mainly due to increased grid losses). To set efficient incentives, network tariff regimes need to differentiate between existing and newly built infrastructure and also between demand and generation dominated network areas. If network charges are linked strongly to the energy withdrawal and feed-in into the grid independently of the current utilization (power) of the grid infrastructure, costs can be higher than would be justified based on actual costs related to the infrastructure. Such higher costs can lead to inefficient price incentives and thus distortions related to the provision of flexibility but also - in case of injection charges - to distorted incentives to install generation units at most efficient locations. Furthermore, the grid charges can increase the incentive for usage of electricity for self-consumption compared to the feed-in of electricity back into the grid.

Variable network charges should be introduced to improve the efficiency of grid use, but the design options must consider trade-offs with transparency and non-distortion.

By providing customers with price signals based on grid conditions, variable network charges can support the efficient use of the grid. Current practices in the EU-27 show that these options are increasingly considered in national debates, but only few MS have practical experience with implementation of variable network charges with more than 2-3 tiers to date. From these examples, we learn that effective locational signals to improve gird utilization and address grid congestions require tailoring signals based on an understanding where and when bottlenecks occur.

The design of variable network charges therefore depends on several factors for differentiation:

- Geographical distribution of generation and consumption: This is not relevant at distributional level for all MS, but a major driver of complexity in larger MS with large regional disparity. The Spanish example of using a different ToU structure for the islands is an extreme example underscoring the need for adjustment to geography.

- DSO structure: If network charges are generally set at DSO-level, the geographical distribution may be inefficiently granular with many DSOs and/or high levels of heterogeneity between DSOs within a MS. The case of Slovenia shows how a national data hub can help manage ToU systems with multiple DSOs.

- Economic structure: The location of industrial production, structural disparities, and political goals of equalizing living conditions within a MS may have to be traded off with the potential gains in system efficiency.

Dynamic structures in tariff regimes should be introduced step by step, and consider the cost-benefit trade-off from needing more measurement technology.

Given currently limited experience with more sophisticated variable network tariffs and the wide range of options in both geographical and temporal granularity of price signals, we conclude that there this is a high-risk-high-reward area of reforming tariffs that should be introduced incrementally.

Regarding the **temporal resolution**, this is first constrained by the level of digitalization. While the ideal for grid operation could be quasi-real time for maximum system reactivity, there is a trade-off with the transparency and simplicity for end users (understandable energy bill especially for households). Especially at the low voltage level, this extends to concerns about energy literacy and whether households can be reasonably expected to manage complex ToU structures. The Spanish case requiring active management of capacity is one example where a good network tariff design comes with potential social concerns.

In addition, the costs for technology needed to implement the solution need to be weighed against the benefits, which hinge on the scale and frequency of bottlenecks without variable charges. The latter holds for both temporal and geographical granularity and therefore scales in cost with the size of the overall network in each MS.

Regarding the design, we recommend a focus on **power-based charges** for variable network charges to complement the energy-based component of ToU designs. The power-based component supports a design that is more cost-reflective and more direct regarding the control of grid conditions, more specifically grid load. Energy-based components can have an additional effect regarding the short-term when and where of consumption and contribute to the reduction of losses, but also come with higher uncertainty for grid users, i.e. a risk of economic inefficiencies in energy consumption. This depends also on national energy markets, considering potential interactions between variable network charges and variable energy market prices, as design choices should avoid distortions between market and grid signals. The example of ToU tariffs of Slovenia follows this approach with predefined power-based charges on contracted capacities for given time slots and a low additional energy-based grid charge related to energy losses in the grid.

If ToU charges have not yet been introduced, power-based charges are also applicable for fixed and non-variable charges as a second-best solution. This is because a large share of infrastructure costs is fixed and only a minor share (e.g. grid losses) is related to the actual use of the infrastructure. If charges are power-based it reflects this aspect better than energy-based charges.

Finally, a politically relevant caveat is the need to justify the different treatment of certain grid users based on location, which can be perceived differently from the original argument of equalizing treatment based purely on cost reflectivity.

Locational price signals should be focused on maximizing grid utilization for better system efficiency, which includes both generation and consumption.

When setting up locational price signals, the differentiation should identify high-stress windows from both generation and consumption. It is important to consider the generation side to make sure that local and national conditions are incorporated in design. This means considering differentiation depending on:

(a) Voltage level, since location signals might have perverse effects if not properly set across grid levels (for a mitigation measure, see the Danish differentiation)

(b) Geographical imbalances, which appear to be highly relevant at distribution level in smaller MS, while other MS encounter issues mainly at transmission level (e.g. redispatch procedures in Germany).

This is linked to the introduction of injection tariffs (see more on this in the dedicated recommendations below). When locational price signals are designed based on network tariff regimes where withdrawal charges dominate, then geographic differentiation is at risk of deepening issues with cost reflectivity from the generation side.

The above recommendations focus on design options rather than opportunity costs of alternative approaches. Regarding locational price signals, **connection charges** are important under the EU approach to network charges (see ACER, 2025)[125], but several MS treat this as a rather separate category of costs. Deep connection charges would constitute a one-time price signal at the time of investment that could also be locationally differentiated based on grid capacity and therefore be conditionally substituted for locational pricing. This especially applies to power-based charges that affect location choice, less so to energy-based charges that mainly provide incentives to adjust operation. The Danish case study shows how connection charges can be incorporated and work well with injection tariffs towards the recovery of different cost components. We therefore recommend

---

[125] ACER (2025). Getting the signals right: Electricity network tariff methodologies in Europe https://www.acer.europa.eu/sites/default/files/documents/Reports/2025-ACER-Electricity-Network-Tariff-Practices.pdf

that the appropriate role of connection charges in the wider network tariff system is considered from early stages of reforming network tariffs, which many MS are currently undertaking.

Injection charges should be evaluated in all MS against the principle of cost reflectivity, such that the generation side contributes adequately to the system costs.

The introduction of injection charges in EU member states mainly serves to support the cost reflectivity of network tariff regimes. In MS that introduced injection charges the key goal was to avoid cross-subsidization between consuming and producing units. However, cost-reflectivity is mainly improved in areas with large amounts of generation that requires substantial grid expansion. In such areas, the cost burden for local consumers can be reduced. Real world examples in Denmark and Sweden indicate that approximately 5% in Denmark and about 16 % in Sweden (in the regional grid) of cost-recovery through injection charges have been achieved. A different implementation and level of injection charges across MS can however lead to distortions that arise from pass-through in the European electricity market, when producers respond to differences in injection charges (see also **Infobox 6** below). Setting up injection charges in the same way across member states would be an important step to prevent negative effects for the EU electricity market, but then there is a trade-off with the locality-based logic for cost-reflectivity sketched above. The subsequent recommendations for injection charges are therefore developed against this background.

Currently, injection charges are not used widely at the distribution level across the EU yet. However, the contribution of generating and prosuming units to network costs is a rising issue across the EU. This is especially the case, when grid areas are becoming generation dominated. Injection tariffs can provide one possible means to improve cost reflectivity in this context. There are caveats to injection charges and we consider them a second-best option to use locational price signals that reflect grid conditions. Nevertheless, injection charges should be considered as a part of the set of options when reforming network tariff regimes at national level.

Regarding the appropriate design of injection tariffs, it is important to consider several aspects that emerge from the analysis of current practices.

- Level effects: High costs must be borne by all grid users, so injection tariffs should be used to offset withdrawal charges. The exemplary practice of Sweden shows how this can be achieved by introducing an injection tariff system that includes consideration of different cost effects with a mix of energy-based, power-based and loss-related design features.

- Imbalances between consumer surplus areas and producer surplus areas (i.e. "generation-heavy" and "consumption-heavy" regions) is important to assess at national level because this affects which aspects of inefficiency are most critical to actual grid conditions. The Danish approach with regional injection-withdrawal balances exemplifies this approach.

- Smoothing or averaging over regional disparities can arise where there are few DSOs or additional locational signals. The appropriateness of smoothing is however ambiguous:

    - Disadvantage: averaging removes steering effect of economic incentives (market distortion)

    - Advantage: smoothing mitigates distributional consequences, especially if costs cannot be clearly attributed to the asset/user as causal

Given that these factors may limit transferability across MS, we recommend that injection tariffs may be initially tailored to national conditions and introduced with priority for certain regions based on their network profile and potentially limited to new assets only. The reasoning for the latter is social acceptance, rather than system efficiency. Introducing injection charges implicitly punishes the early adopters of renewable generation because it changes the net present value of their investment ex-post. This perception of fair policy treatment applies especially for households and small businesses, but for larger assets the application poses higher risks of distorting location choices of renewable generation investments and this trade-off must be considered. Exemptions for certain user groups should be considered only if justifications for deviations from cost-reflectiveness and non-discrimination are arguable by trade-offs with other principles.

The design of injection charges should be based on quantitative studies to assess the mechanisms by which their introduction affects both grid and market factors.

While injection charges have clear potential with respect to improving cost reflectivity, an effective design of these charges should follow an evaluation of:

(a) what specific costs assets cause, and

(b) where in the network the benefits accrue

We therefore recommend quantitative studies to be conducted to explore the mechanisms. The EU can support MS by providing guidance on a common methodology for this assessment and demonstrate its application with selected MS. Study-based design is especially important for lower voltage levels, where it is not trivial to attribute the costs caused by injection to really achieve cost reflectivity and therefore a common approach can support harmonization. This could be done through ACER or CEER depending on the nature of the communication.

From a theoretical perspective, a uniform approach across EU MS to injection tariffs would pose the least market distortion and mitigate concerns about international spillover effects. However, complete harmonization by regulatory means does not appear feasible given the analysis of current practices, as there is no one-size-fits-all solution for all MS. Factors to consider include:

- Number of DSOs: with many DSOs, there may be very different levels appropriate across regions within a MS, but such high differentiation carries the risk of distortion.

- Current state of market for renewables: where renewable penetration remains underdeveloped, MS may have to consider other instruments to counterbalance slow-down of renewable expansion in critical areas, for example through tailored fiscal support.

- Treatment of existing assets: Several MS handle this with so-called "grandfathering" provisions, which avoid implicit punishment of early adopters in a trade-off with system efficiency.

The above factors already capture trade-offs between system efficiency and market factors, as well as broader economic concerns with high relevance to EU objectives.[126] This extends to the fundamental design choice regarding the relative weights of power-/capacity- and energy-based designs, as evident in the different designs employed in Sweden and Denmark. Power-based charges, or more accurately the power-based weight in overall tariff design, can provide more direct levers towards cost reflectiveness.

However, there may be adverse economic effects of power-based injection charges that go beyond the effects of network efficiency. **Infobox 6** outlines these arguments briefly. Their assessment is outside the scope of the present study, but critical for alignment between policy objectives going forward.

[126] In line with the ACER report on network tariffs (2025), we support the observation that NRAs face increasing opposition from stakeholders and political pressure. Therefore, economic trade-offs should at least be made explicit.

Infobox 6

Box 6: Economic caveats regarding power-based injection charges

The present study agrees with the ACER report on the potential of using power-based charges to address current gaps in cost-reflectivity. Recent work from the perspective of economic theory[127], however, cautions against power-based design of injection charges on the grounds of adverse economic effects:

- Distortion of location choices with negative welfare consequences
- Re-distribution of costs onto consumers (economic incidence) resulting from pass-through in wholesale prices

In addition, economic theory also shows that injection charges can have cross-border effects when not harmonized across countries. The welfare effects of this again depend on pass-through of prices within the national electricity system.

These arguments are based on nationwide uniform injection tariffs and not specific to distribution grids, but the basic economic mechanism holds. The pass-through and price effects of power-based injection charges at distribution level are not easily deduced and likely diluted from the theoretical benchmark.

The present study focuses on recommendations based on current practices, but notes the above concerns as a caveat to be monitored at the EU level.

SUBTOPIC 2: Regulatory incentives for DSOs

Anticipatory investments: the EU policy discourse should adopt and promote definition by the European Commission guidance to sharpen clarity and allow comparison across MS.

In the interview phase, we encountered widespread uncertainty of what is meant by anticipatory investments. Current references in policy documents were not deemed clear. By definition, all investments are somewhat forward-looking from the perspective of stakeholders. Hence, the key aspect to emphasize based on our comparative study is a higher tolerance of uncertainty for future developments beyond current connection requests.

The very recently provided definition in the applicable EU guidance captures this aspect well:

> *"[…] Anticipatory investments [are] investments into grid infrastructure assets that proactively address network development needs beyond the ones corresponding to reinforcements relating to currently existing grid connection requests by generation or demand projects. Anticipatory investments are forward-looking network investments based on identified medium- and long-term network needs, justified in network development plans, based on scenarios that project plausible trajectories of generation and demand capacities that support energy, climate and industrial policies, including the National Energy and Climate Plans."*

---

[127] Hirth et al. (2025). Injection charges for cross-border grid cost recovery. Study by Neon Energy and Consentec on behalf of TenneT TSO. https://neon.energy/Neon-Consentec-Injection-Charges.pdf

(Source: European Commission, 2025, Section 2.1)[128]

We recommend that this definition is used consistently at the EU level going forward because the present study underscores that MS currently face both the need to address anticipatory investments and express uncertainty over whether their current practices fall under this term.

Anticipatory investments should not be considered a cost category of their own, but rather reflected in different cost categories.

Related to the previous point, anticipatory investments do not fit into current classifications of cost types laid out in **cost approval**. Rather, the present study understands that different investment types can be anticipatory in nature depending on the underlying uncertainty over future developments.[129]

Regarding the implementation, simply allowing anticipatory investments in regulatory frameworks will likely not lead to higher adoption. Experience from the deep dives suggest that this is embedded with:

- NRA processes/indicators: all else equal, a DSO that does more anticipatory investments could be less cost-efficient if indicators (e.g., debt ratios or net present value at firm-level; depreciation schedules set by regulation) do not reward or reflect such investments, which is currently a remaining obstacle.

- Existing disbalances: As anticipatory investments may lead to higher OPEX (due to operation and maintenance of infrastructure dimensioned with a view to future needs), the established efficiency-focused approach to OPEX may implicitly discourage such investments. Thus, the OPEX-related implications need to considered in a framework for anticipatory investments as well. The Danish case demonstrates how both the return on the asset base and the cost base including OPEX can be considered when allowing revenue adjustments due to specific investment measures.

The EU should support the development of a methodology for the cost-benefit analysis regarding the higher uncertainty of anticipatory investments.

Extending from the previous point, it should be noted that there are linkages between anticipatory investments, connection charges, and network planning should be considered in policy alignment efforts. The approval process for grid development is linked to the recognition of resulting expenditures in the DSO revenue regulation. Adapting cost categories to incorporate anticipation is first a question for regulation, but should ideally be reflected in DNDPs as well. Similarly, there are linkages to deep connection charges, since anticipatory investments might have prohibitively high costs for the first users.[130] There is also an indirect link to grid connection requests: the ability to pursue anticipatory investments (given access to funding) may improve the connection conditions, especially for certain user groups or in particular regional situations (e.g. structural development of rural areas).

It appears important to provide MS with a common framework method on how to adapt cost-benefit analysis for the higher uncertainty and how to use this as a basis for approval of anticipatory investments. Even though anticipatory investments are addressed in the revised Electricity Regulation (Art. 18 para. 2 (a), para. 8 and para. 9 (f)), no dedicated assessment methodologies

[128] European Commission (2025). Commission Notice on a guidance on anticipatory investments for developing forward-looking electricity networkshttps://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52025XC03179&qid=1750695420666

[129] The data collected for this study are thus in agreement with the EU DSO Entity's recently published analysis: EU DSO Entity (2025). Anticipatory Investments. https://eudsoentity.eu/wp-content/uploads/2025/02/Paper-on-anticipatory-investment_FINAL-PDF.pdf

[130] For a more detailed discussion of trade-offs in the treatment of anticipatory investments within existing regulatory frameworks see: EU DSO Entity (2025). Anticipatory Investments. https://eudsoentity.eu/wp-content/uploads/2025/02/Paper-on-anticipatory-investment_FINAL-PDF.pdf

could be identified on the MS level through desk research and expert interviews. At the same time, regulatory experience under the TEN-E Regulation can be utilised for the methodology development. As infrastructure projects of common interest eligible for regulatory incentives in NRA competence due to higher risk (Art. 11 TEN-E Regulation) may include anticipatory investments and, accordingly, the higher risk may be due to under-recovery of costs, the provision partially overlaps or, at least, indicates similarity to the treatment of anticipatory investments in distribution grids in general. According to Art. 17 para. 6 TEN-E Regulation, NRAs need to publish by 24.09.2023 methodologies for assessing infrastructure projects with higher risk. During this study, such methodologies (for projects of common interest) were identified in individual MS (e. g. HU). A systematic review of NRAs' risk assessment methodologies under Art. 17 TEN-E Regulation can help identify best practices in the MS and, thus, inform the methodology development.

Regulatory framework should ensure that there is no time gap between incurring expenses and their recognition for revenue regulation.

Time lags between expense and recognition are an obstacle for DSO. We recommend that the design category **flexibility during regulatory period** receives greater attention. In many cost recovery models, DSOs face delays in recovering costs when conditions change within a regulatory period. Adapting procedural rules would prevent delays from discouraging investments.

Approval-based revenue cap (or recognised cost) adjustment to reflect new developments (or new data) during a regulatory period is a possible approach to eliminate the time gap. In certain cases, an automatic adjustment may be viable if it is triggered by a factor outside DSO's control and linked to appropriate objective criteria. For example, an automatic indicator applied in Denmark is linked to an increased number of meters, stations and/or amount of electricity delivered in the low-voltage grid. Alternatively, forecasted expenditures for the following regulatory years may be considered when determining allowed revenue for a given regulatory year, as currently practiced in Croatia. While the Croatian forward-looking cost model may not be a one-size-fits-all transferrable to larger MS with more complex incentive regulation based on a longer regulatory period, elements of annual monitoring could be implemented. Ireland serves as an example, as its increasingly output-oriented model incorporates a reporting and monitoring framework with annual revenue reviews. Annual updates of forecasts that underly investments under the Agile Investment Framework mechanisms, allow the regulator to monitor their anticipated use and, thus, the impact on the grid tariffs.

Furthermore, the possibility of recognising costs of assets under construction, in particular those incurred before construction start, needs to be examined in more detail. If enabled subject to examination by the regulator that such early costs were incurred efficiently, their recognition for the revenue allowance might lift a disincentive for initial assessment and preparation of anticipatory investments.

NRAs should take into account the use of performance-based incentives for smart grid solutions, incl. smart meters, within regulatory frameworks

Digitalisation of electricity distribution grids, including smart meter roll-out, is an essential prerequisite for preparing the grid for growing RES integration and operating the grid efficiently with dynamic tariffs, locational signals and in a cost-reflective way (see section 4.3). The traditional approach of calculating the return based on the CAPEX does not incentivize **OPEX-driven investments**, such as for smart grid systems. In addition, piloting innovative solutions is associated with higher risk and may be discouraged in the regulatory framework rewarding cost-efficiency.

Piloting smart grid solutions that have not yet reached commercial maturity can be facilitated by an additional revenue allowance on a case-by-case project scrutiny by the NRA, e. g. as enabled by the Innovation and R&D performance incentive in Ireland. To advance deployment of commercially available technologies, the most basic being smart meters or observability of transformer stations, NRAs could proactively set and monitor implementation of specific objectives based on policy priorities, historic and current developments, including regular review of incentive levels to ensure their efficiency. The incentive mechanism operating with objective-specific upside (rewards) and downside (penalties) adjustments to the allowed revenue used in the Irish framework can be used as a best practice. Ultimately, alleviating CAPEX-bias present in the revenue regulation is crucial for facilitating smart grid investments. The possibility of shifting the *ex-ante* revenue allowance between OPEX and CAPEX to implement the most efficient solution for achieving an outcome is an advanced approach to this end.

6.3. Timely and transparent treatment of grid connection requests

SUBTOPIC 1: Determination of grid connection potential

Methodologies applied to assess capacity should be made more transparent and harmonized across DSOs within Member States.

Currently, the methods and indicators for the determination of grid connection potential are not transparent. Existing EU frameworks offer only broad guidance and MS practices are not comparable, leading to a policy gap. Even though different tools exist in MS, the methodologies are not comparable. The data collected in this study thus emphasize how critical Action 6 of the grid action plan is in promoting harmonization, transparency, and visibility. Establishing a consistent framework for assessing and publishing available grid hosting capacity is essential to enable efficient project planning and reduce uncertainty for developers.

The first step would be to provide more clarity on what is meant by capacity in the different approaches. Methods should differentiate between volumes of capacity already requested (i.e. projects or requests in pipeline, even if there is no queue) and the available grid capacity for new applications. For the latter, it would be useful to distinguish between technical and contractual capacity available, which becomes relevant when flexible connection agreements are employed.

In MS that do not apply strong filtering criteria at the permitting stage, the ex-ante probability of finalizing the grid connection application could be included as a practically meaningful criterium.[131]

From there, harmonization across DSOs within a MS should be done, ideally with leadership of the NRA and through common portals that already exist (if available). The minimum requirement would be a listing or otherwise quantitative representation, although we do not recommend mandating the same tool or map in order to avoid imposing parallel structures on DSOs who have already innovated. Complete harmonization appears infeasible at the EU level because methods and terms used are embedded in national processes and contingent on the level of digitalization.

Harmonization of tools at EU-level can be advanced by focusing on requirements, rather than on the specifics of implementation.

At the EU level, we recommend that harmonization efforts focus on requirements regarding the contents of grid capacity information, but leave implementation aspects such as data formats and map layouts to the MS. With the Capacitypedia project (see **Infobox 5** in section 5.2), an initiative for more harmonization is underway. Seeing that this is still at the conceptual phase, the recommendation from this study is that harmonization should be focused on *how* it is done rather than specifying technical aspects. We see the objective of this recommendation in establishing transparency for policy makers and other users to monitor developments of grid capacity and congestion. Based on the review of grid capacity tools across the EU-27 (see summary table in Appendix 1), harmonization for this purpose can help by addressing both the requirements and the principles applied for harmonization.

Recommended minimum requirements for content are:

- Time stamp with last update
- Definition of grid capacity to display
- Link to methods document on that page
- Traffic light-style indication of critical areas

[131] Ireland is an example for relatively weak filtering, for a comparison, see also: Eurelectric (2025). Grid Connection queues in distribution networks. https://www.eurelectric.org/publications/from-backlog-to-breakthrough-managing-connection-queues-in-distribution-networks/

Recommended principles in the requirements could be:

- Uniform indicators/definitions within a MS
- Digital and standardized processes, with preference for existing software
- Requirement for basic interoperability
- User transparency

From the comparison of the EU-27, it appears sensible to allow MS to keep with existing tools and build on existing processes. The heterogeneity in functional tools in the deep dives for Estonia and Germany shows that MS have already invested substantially in such systems and are increasingly tailoring them to local needs. Requiring advanced MS to build up parallel systems and re-design processes that work already should be avoided. One option to explore would be to include reporting of basic capacity measures in DNDP development, since this is already being developed in many MS. This option is beneficial if and only if reporting of such figures is not otherwise covered already. While some MS have already implemented this practice, all MS should ensure quarterly updates are provided as requested with the necessary level of detail and up-to-date information. The minimum requirement of a timestamp and quantitative measures of capacity would already advance MS transparency to a basic common level.

In conclusion, user transparency should remain a central objective of all harmonization efforts. Clear, consistent, and regularly updated information on grid capacity empowers a wide range of stakeholders to make informed decisions. Transparent access to comparable data helps identify grid bottlenecks, assess connection opportunities, and plan infrastructure investments more effectively. By focusing harmonization on minimum content requirements and core principles, while allowing MS flexibility in implementation, the EU can strike a balance between consistency and practicality.

The introduction of an EU-wide transparency platform should be pursued with a focus on interface design and stakeholder heterogeneity.

From the perspective of EU policy and especially the Electricity Directive, the common portal or platform from the Capacitypedia project would further improve transparency if all MS were to report capacity measures. While details on this platform and its interface are not yet public, the approach focuses on linking existing tools rather than replacing them. Our study supports this approach. Several MS, or respectively the DSOs in the MS are setting-up or have implemented transparency platforms to show connection capacity and focused on serving the needs of their grid users. An EU-wide platform would need a standardized, simple interface for data entry/transmission, ideally built on an existing reporting interface. We recommend making the information available via common interfaces and avoid the upload of documents.

To realise the benefits of the platform especially for MS with many DSOs it should be set-up in a way that existing approaches can be easily integrated. Interoperability and the usage of common standards could support and advances the principles of timeliness and transparency specifically referencing the provisions of the Electricity directive. We recommend that the transparency should be in collaboration or at least through consultation with **EU Data Spaces Initiatives** that are being built for the purpose of secure European data exchange.[132]

Based on the current practices in the EU-27, the benefits of an EU-wide transparency platform vary by grid user group. For local and regional grid users—such as households, energy communities, municipalities, and companies operating within a DSO's region—a DSO-specific informational tool is mostly sufficient. However, for trans-regional or international project developers and grid users, such as those involved in EV infrastructure or renewable energy (RE) development, harmonization offers greater benefits. To avoid disadvantaging local consumers or producers, the costs of preparing and providing the data should be borne by those who benefit from harmonization.

[132] See the link to the EU-level initiative : https://digital-strategy.ec.europa.eu/en/policies/data-spaces

SUBTOPIC 2: Measures in case of lacking capacity

More clarity should be provided regarding the use cases for flexible connection agreements in current policy and in practical experience.

Currently, the definitions and terms around flexible or conditional grid connections are not fully clear and not used consistently. Use cases here means especially the distinction between interim measures and permanent solutions.

The basic definition is provided in Directive 2024/1711, which defines flexible connection agreements as

> *"(…) a set of agreed conditions for connecting electrical capacity to the grid that includes conditions to limit and control the electricity injection to and withdrawal from the transmission network or distribution network.''* [133]

However, the further provisions regarding flexible connection agreements in Article 6 of the Electricity Directive[134] are still relatively wide, which is positive to leave MS room to find suitable arrangements but brings uncertainty over the requirements for implementing flexible connection agreements. The reference to the "*most efficient solution*" (Article 6, 1(c)) does not provide reference to evaluation criteria, with a lack of clarity on how to evaluate and implement such solutions at the national or sub-national level.

The Electricity Directive explicitly allows flexible connection agreements as a permanent solution following Article 6, 1(c), yet most measures reported by MS in the status quo are interim and/or temporary. To help support this intended permanent approach to using flexible connection agreements, it would be helpful to document experiences where current temporary solutions are turned into permanent ones over the coming years.

This is important also regarding the difference between the two use cases: DSOs should assess the risk of cost inefficiencies differently for interim solutions than for permanent approaches because the technology needed for automatic control to implement flexible connection agreements in the short-run becomes obsolete as soon as grid expansion happens. With Article 6 1(b) and 2(c) stipulating that conversion to firm connections should be enabled, these cost considerations become relevant.

This recommendation could be implemented with a combination of guidance documents provided to NRAs (e.g. through ACER) or clarification in the legal text itself. The network code on demand response is also set to contribute to clarification in this matter, but it mainly specifies criteria to apply for integrating flexible connection agreements with other market aspects such as local services (e.g. Article 41), which means that open questions remain on the practical application of principles in legislation in the DSOs operation.

Flexible connection agreements could be supported with a model-based study laying out the key parameters for policy design.

Related to the previous point, we recommend to provide methodological support with a model-based study at the EU-level. This could clarify how to perform cost-benefit analysis based on basic high-level use cases. In the status quo, we identify a chicken-and-egg-type problem: building confidence in the broader, long-term use of flexible connection agreements needs better data, but without this confidence, empirical data are lacking. A model-based study would provide a first step to support confidence building.

For such a study, the first objective would be to model the economic optimization problem, i.e. to understand incentive structures when flexible connection agreements come with different (lower)

---

[133] Article 2 of Directive 2024/1711 amending Directives (EU) 2018/2001 and (EU) 2019/944 as regards improving the Union's electricity market design. L_202401711EN.000101.fmx.xml

[134] https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:02019L0944-20240716

grid fees than normal. Then, the study could include a comparison of the value for short-term and long-term application (i.e. grid utilization vs. grid expansion) and how the benefits accrue over time. Ideally, the modelling would include a differentiation by voltage level and/or grid situation. In particular, we observe that current practices are built on capacity constraints stemming from both generation or consumption and it is not clear how the implications differ.

To be actionable, the document should also provide practical guidance to NRAs and DSOs with the identification of key parameters (e.g. grid, geography) that would alter the cost-benefit analysis in specific MS. Such a study could support MS in the transition from viewing flexible connection agreements a bridge solution to current bottlenecks towards viewing the instrument as a means to improve grid utilization as part of the permanent toolbox.

Finally, we observe that current conditions are targeting grid users, but there is also an option to place regulatory conditions that incentivize the DSOs: steering options in exchange for tighter rules to expedite grid connection requests. **Infobox 7** summarizes this alternative. However, the study also shows that many MS have not yet reached the high level of grid observability that is needed for active management – this is a pre-requisite regardless of whether consumer-facing flexible agreements or direct steering interventions are used to manage congestion.

Infobox 7

Box 7: Steering options for DSOs as an alternative mechanism

The option for system operators to intervene in network is referred to as "mandatory curtailment" in the scientific literature. For example, Grimm et al. (2020) show that allowing the DSO to intervene and curtail in peak times can reduce system costs.[135]

An example for such an approach currently being tried is the German case (§14a ENWG in national legislation). DSOs can steer controllable consumption assets in the lower voltage levels, but then cannot reject grid connection requests for such devices.

Such practices are clearly related to the discussion around FCAs. Here, the condition is placed on the DSO on how to treat other grid users, not individual conditions for contracted capacity as in the EU definition of flexible connection agreements.

In practice, giving DSOs steering control will not be politically feasible in all MS. These mechanisms are outside the scope of the current study, which is focused on transparency and timeliness, but should be at least acknowledged as part of the solution space for handling capacity constraints.

SUBTOPIC 3: Process for grid connection requests

Increasing lead times from a backlog of pending grid connection requests have to be tackled with a portfolio of tools specific to the root problems.

Across Europe, the volume of grid connection requests is increasing, and also the composition of the application pool is changing. Examples for connection types on the rise are storage and data centres, with different exposure levels across MS. Queues are building in several MS, when gird capacity in the distribution grid is largely utilized. In this case, flexible connection agreements can help in the short-run. Prioritization schemes instead of the common first-come-first-serve process would be beneficial, but the recent court rejection of social prioritization in the Netherlands cautions that there are national legal barriers to getting the taxonomy of prioritization right. In other MS, queues build

[135] Grimm, V., Grübel, J., Rückel, B., Sölch, C., & Zöttl, G. (2020). Storage investment and network expansion in distribution networks: The impact of regulatory frameworks. Applied Energy, 262, 114017.

up more/additionally from a lack of filtering (e.g. Ireland), which is better addressed with regulatory changes regarding the entry conditions for permitting.

While grid congestion is the major factor limiting approval, other causes for backlogs are seen in administrative procedures and speculative requests. There is a need to tackle the different causes with a portfolio of tools specific to the root problems. Quantitative indicators of lead time make these problems transparent but are **(a)** difficult to interpret due to fragmentation and **(b)** capture the symptoms originating from different problems. We therefore recommend that policy adjustments are focused on tackling the underlying issues additionally to monitoring the lead time itself. In some MS, backlog is also starting to build from DSO resource constraints in handling requests, and regulatory measures for lead times at EU level would address the symptom instead of the cause. Bureaucracy and especially digitalization would then be more suitable target indicators for policy measures.

Table 10 presents this situation in the form of a toolbox, making the recommendation actionable to questions of policy design. Items presented as "if"-statements designate options that follow from the previous row.

Table 10: Toolbox for Addressing Lead Times

No.	Steps to take		Issue addressed
	Preventive Action (before queues build)		
1	Ensure that entry criteria are set properly.		Lack of Regulation
2	Allow filtering based on fulfilment of milestones.		Lack of Regulation
3	**If** filtering reveals widespread/systematic issues, enact specific rules/penalties for speculative applications.		Insufficient Monitoring
4	Link lead times from current grid requests with network development planning.		Lack of Alignment
	Concurrent Action (when queues emerge)		
5	Allow the use of flexible connection agreements.		Grid congestion
6	**If** using flexible connection agreements, consider options to: • exploit complementary load profiles (incl. permanent instead of interim solution) • employ economic incentives for grid users in return for their acceptance of limitations (e.g. via reduced network fees)		Grid congestion
7	Prioritize only if necessary (cf. Article 6 Electricity Directive).		Grid congestion
8	**If** prioritization is needed, dedicate sufficient resources to develop a clear and transparent taxonomy/criteria.		Lack of legislation[136]
9	Enforce transparent handling of current backlog at DSO level.		Administrative Constraint

[136] Legislation or regulation depending on national processes and responsibilities.

	Reactive Action (to address future needs based on empirical data)		
10	Support better digital processes at DSO-level.		Administrative constraint
11	Set incentives for sparing requests of grid capacity and monitor the outcome.		Inefficient capacity assignment
12	**If** overreservation is systematic, consider use-it-or-loose-it policies to disincentivize the practice.		Inefficient capacity assignment
13	Facilitate use of further anticipatory investments based on updated data trends.		Regulatory long-term constraint
14	Support grid observability and use of forecasting tools based on this empirical data.		Lack of long-term monitoring

Several measures listed under reactive action would ideally also used pro-actively as part of preventive action. We make this split mainly based on the data that are available at the two points in time and therefore the tailoring of solutions to the extent and specificities in the respective MS. For example, anticipatory investments and digitalization investments would certainly help ex ante, but may drive up system costs. When empirical data are available, policy dialogues and adjustments can be taken with better information on costs/benefits and thus overcome resistance to change, which is the purpose of the measures listed under reactive measures that serve the long-run.

The full policy toolbox should be exploited in MS that already have queues, whereas MS with no known queueing problems should conduct a basic readiness assessment regarding the above factors (see preventive action). This is because recent experiences show that queues are an increasing issue in European distribution grid development – at least 15 MS are experiencing queues already, although many problems are confined to local areas or specific assets for now. On the one hand, this reflects dynamics of decentralization: as the energy transition becomes more dynamic, connection requests volumes increase. On the other hand, queues build over several stages related to construction, planning and approval that vary across voltage levels and user types. Hence, while backlogs are not yet widespread across Europe to date, several MS who did encounter problems had to resort to drastic measures such as suspending new applications and rejecting outright. For MS who have not reached that point, proactive readiness assessments are therefore timely.

Best practices and experiences from other sectors dealing with fragmentation could support user-friendly system development.

From the perspective of grid users, current processes are often highly fragmented and this segmentation is often very specific by technology. The general principle should be to keep administrative burden as low as possible for the consumer, but this is challenging with highly technical processes.

In the energy sector, the decentralization and the increasingly active role of small-scale grid users is relatively new. Lessons learnt from other sectors could help find solutions for dealing with and streamlining the processes to reduce administrative burden for the grid user and the DSOs.

Sectors that have dealt with high fragmentation and high regulatory requirements could be digitalization of public services or tax assistance systems. These have previously struggled with similar issues and are increasingly developing systems based on user-centric design (UX). The EU DSO Entity and/or CEER could be possible starting points for a series of workshops or best practice exchange. Such an exchange could also help to facilitate the diffusion of new grid-user groups with many technologies (e.g. energy communities) because it would focus the discourse on principles of user access and go beyond technology specification.

6.4. Cross-cutting observations

The recommendations above adhere to the study logic of topic areas, subtopics and design categories. This distinction enables the structured comparison of a multitude of policy options and practices across the EU-27. However, there are also linkages between the topic areas that emerge from the research and are important for policy design and especially policy alignment between the different institutional levels involved in distribution grids. The following aims to make these cross-cutting observations explicit.

Grid observability. Several of the selected practices in the deep dives are helping to manage increasing complexity. The transferability of these practices, however, hinges on the distribution grid being digitalized, i.e. grid observability is a precondition to advanced practices across topic areas. This applies for example to better forecasting of flexibility (6.1), to using complex tariff designs with higher temporal and spatial resolution of price signals (ToU) and to more detailed cost recovery models (see 6.2), or the management of flexible connection agreements (6.3). Smart meters are the most prominent example for tariffs, but grid observability goes further. Especially for handling grid connections, it is needed to effectively utilize the full "toolbox" presented in **Table 10**. However, grid observability at the medium and low voltage levels remains incomplete and real-time data remains elusive. Without progress in this area, insights from the current advanced practices are not replicable on EU-wide scale.

Incentive structures. For the context of distribution grids, incentives are used in two ways. On the one hand, there is the question of which incentives should be set for DSOs to accommodate new grid users or move towards smartening the grid. Regulation is critical in this regard. On the other hand, incentives also apply on the grid user side: tariff design provides prices signals (6.2), capacity maps provide incentives for location choices (6.3). In some instances, these two pieces could be combined for systemic benefits – hence the term "incentive structures". For example, it would be advantageous to employ shallow connection charges (user incentive) in places where grids can be finalized in relatively short periods of time (information from planning, 6.1).

Linking incentive structures and grid observability. Linking grid observability and incentive structures can improve grid operation, optimize grid connections and reduce connection queues. If measured peak load of single grid users during system peak periods is known, the grid operator has a better understanding of available grid capacity. If the measured peak load is linked to network charges (e.g. via capacity-based charges) and can be adapted by the grid users according to their needs, the combination of grid observability and incentives could lead to a reduction of peak capacity needs of the grid. Available grid capacity to connect new assets to the grid can be identified and users have incentives to adapt their capacity need to their current demand.

Anticipation. Forward-looking practices, most prominently in anticipatory investments, are a recurring theme that represents the need for long-term decision making under high uncertainty. While anticipatory investments per se are presented in the study under network tariff *regulation* (see 6.2), the question of how to balance the risks and needs of a changing energy system is also critical for the other topics. Anticipation of this change helps prevent the spread of grid congestion that is already felt in several MS (6.3), and it feeds into scenario building in planning processes (6.1). The recommendations thus emphasize the importance of reforming both established processes and regulatory frameworks to accommodate the transition period.

7. CONCLUSION

The present report shows the state of play for distribution grids in Europe. It covers the current practices in 27 member states along three topic areas:

- **1)** Network development planning,
- **2)** Network tariff regimes and regulatory incentives, and
- **3)** Timely and transparent treatment of grid connection requests.

For network development planning, the study provides a snapshot of distribution network development planning against a context of changing national processes. In many MS, planning at distribution level is a work in progress. MS are transitioning from simpler documents focused on network *expansion* to planning documents with greater scope and depths, i.e. fully advanced DNDPs (see Table 9 in section 6.1). Better harmonization, greater actionability and the consideration of flexibility options are among the key challenges. This development is only possible through closer coordination with TSOs and NRAs, but especially in MS with many DSOs also requires better alignment within a country. Regarding the outlook, the Network Code on Demand Response is a major pending policy that will have an impact on further development in this area.

For network tariff regimes and regulatory incentives, among the key design categories to be addressed in the near future are variable network charges that reflect actual grid conditions (incl. injection) and anticipatory investments that must be made under high uncertainty. While the former is a critical challenge to mitigate shortcomings in cost reflectiveness already visible, the latter is critical for coping in the future. Neither is currently applied widely across the EU, but the first experiences presented here as deep dives provide insights on how changing network cost structures can be addressed through adjustments in tariffs and regulation. In regulatory regimes, the current frameworks are also proving too rigid to allow DSOs to cope with their changing and expanding role in a changing energy system. MS have taken different approaches to adjusting their regulatory frameworks to eliminate delays in cost recovery and allow forward-looking measures, enabling DSOs to future-proof their networks. In many MS, these reforms are ongoing or under debate, which makes the presentation of deep dives on this topic area timely and urgent.

For grid connection requests, this study is making a concerted effort on better understanding current practices and the underlying issues. This topic area has only recently begun to receive attention. Transparency is being increased by capacity maps, which remain heterogeneous in quality and scope. Timeliness is difficult to assess against the background of diverging and overlapping issues that ultimately all contribute to a slower integration of renewables. There are remaining gaps in policy implementation, but also in policy development to clarify how timeliness and transparency can be become actionable principles while not over-burdening DSOs with reporting in a high-volume business process. In the outlook, the upcoming guidance on grid connection requests by the European Commission will be the next step in this direction, while much ground remains to be covered.

While these three topic areas are analysed and treated separately, there are also connections that emerge between them. Network tariff regulation has an effect on the solution space available for network planning. Network planning has an influence on congestion problems, which in turn constrain how increasing volumes of grid connection requests can be handled.

8. APPENDIX

8.1. Appendix 1: Summary tables

The appendix contains summary tables that give an overview of EU-wide practices organized by topic area. These tables complement the MS factsheets in Appendix 2 which provide information for each country separately.

The abbreviation N/A is used here for "no data available" / "no answer" to make data gaps transparent. In some cases, information is simply not applicable, this is then specified and visually indicated (e.g. for cases like harmonization across DSOs when some MS only have 1 DSO).

1. Frequency of DNDP updates

- In 7 MS DNDPs are updated every year, while in 20 MS DNDPs are updated every other year

	Frequency of updates, in years	Comment
AT	2	
BE	2	
BG	1	Short-term and long-term plans but only to provide information for the TSO's NDP; short-term: every year for period of two years
HR	1	
CY	2	
CZ	1	
DK	2	
EE	2	
FI	2	
FR	2	
DE	2	
GR	2	
HU	1	
IE	2	
IT	2	
LV	1	However, to be replaced with 2

LT	2	
LU	2	
MT	2	
NL	2	
PL	2	
PT	2	
RO	2	However, with annual investment plan submission
SK	1	
SI	2	
ES	1	
SE	2	

2. TSO – DSO coordination

- For 18 MS alignment between TSO and DSO takes place, albeit in different forms.
- In 3 MS coordination with the TSO only takes place via the public consultation.
- For 2 MS it is unclear whether coordination between TSO and DSO(s) takes place.
- In Malta there is no TSO, hence this design category is not applicable.

	Does coordination happen?	Comment
AT	Yes	Coherence with integrated grid infrastructure plan and the current NDP for the transmission grid is required
BE	Yes	The document used for analysing DSO data is sent by CWaPE (Regional Regulatory Authority) to all DSO in Flanders. This was used for analysing the TSO's 2022-2029 adaptation plan, ensuring consistency between the transmission and distribution network operators' scenarios. Some DSOs have updated their data based on recent coordination meetings with the TSO. Also, in the Flemish case alignment with the TSO has been done in light of for example which scenarios to use.
BG	Yes, at least from DSO to TSO	According to the rules for management of electricity distribution networks, DSOs shall provide information for the development plan of the TSO
HR	Yes	Development plan shall be in accordance with the TSOs TYNDP. (Energy Market Law) The TSO and DSO hold coordinating meetings and align their activities, especially concerning: demand forecast

		scenarios, planning and economical evaluation (CBA) of jointly owned infrastructure, connection of DG having impact on transmission system.
CY	Unclear	NRA is responsible for the alignment of the TSO and DSO plans. Unclear to what extent this alignment takes place.
CZ	Yes	DSOs shall submit the assumption of electricity consumption and maximum load at transfer points between the transmission and distribution system in individual years for the period of the next 10 years; data required for network calculations of steady-state network operations and short-circuit conditions.
DK	Yes	DSOs have ongoing daily discussion/communication with the TSO. In practice, the TSO is consulted, but DSOs remain responsible for their own DNDP. Typically, TSO feedback on the DNDP is already incorporated into the draft version of the DSO's plan. The TSO does not usually submit public comments, because most issues are resolved beforehand. Additionally, Denmark has a "data hub" (managed by a TSO subsidiary) containing electricity consumption/production data. DSOs can use this data hub to support planning purposes.
EE	Yes	DNDP explicitly refers to studies performed by the TSO.
FI	Yes	Elenia (one DSO) cooperates with Fingrid (TSO) and align their development plans with Fingrid's forecasts. Section 19 of the Electricity Market Act mandates cooperation.
FR	Yes	Alignment is present, amongst other by means of regional renewable energy master plans (S3REnR), the TSO (RTE) and DSO align. The TSO makes these plans in agreement with the DSOs. Alignment with regard to TSO NDP & data is not mentioned explicitly.
DE	Yes	Coordinated action between DSOs and TSOs, as well as DSOs within the same planning region obliged by law (EnWG 14d)
GR	Unclear	NRA is responsible for the alignment of the TSO and DSO plans. Unclear to what extent this alignment takes place.
HU	Yes	There is one integrated TSO-DSO development plan. Continuous data exchange takes place.
IE	Only in public consultation	TSO has the option to provide feedback during consultation period; no further information available so far.
IT	Yes	Alignment with the TSO takes place in their NDP, data is published at an aggregated level by the NRA.
LV	Only in public consultation	No indication of alignment with TSO apart from public consultation. National Energy Strategy and TSO TYNDP are consulted.
LT	Yes, partly	In preparing the DNDP, TSO TYNDP was considered. However, unclear to what extent the detail of alignment is.

LU	Yes	Largest DSO (Creos) is also the TSO in Luxembourg
MT	Not applicable	There is no TSO in Malta
NL	Yes	The industry association of system operators 'Netbeheer Nederland' has a taskforce where TSO and DSOs together align on scenarios.
PL	Yes	Plans for the development of the transmission grid and the 110kV distribution network are coordinated between TSO and the 5 biggest DSOs.
PT	Yes	The DNDP is developed taking into account the development plans of the TSO. TSO receives the proposal of the plan and provides opinions, and may suggest changes and amendments.
RO	Only in public consultation	TSO-DSO alignment is not required by the Law, but they are involved in the public consultation
SK	Yes	During planning, the DNDP is based on the consumption and other data contained in the TYNDP
SI	Yes	Regulatory framework promotes integrated planning: The distribution operator shall also consult with the transmission system operator before public publication of the development plan.
ES	Yes, at least from DSO to TSO	Alignment information available only from the side of TSO TYNDP. This plan is aligned with DSO information, but no coordination of the plans takes place between the DSOs and the TSO formally. In case of needs or requirements from the TSO, DSOs have to contact the Ministry and the NRA.
SE	Yes	DSOs align their plans with TSO through joint long-term forecasting and shared methodologies to streamline grid expansions.

3. Harmonisation between DSOs

Note: MS with 1 DSO (or in some cases with smaller DSOs that are below the reporting threshold) – are marked dark grey, as harmonisation between DSOs is not (or less) applicable in these MS.

- Among the MS with more than 1 main DSO, there are 15 MS that provide guidance on a common structure (either by providing a template, by listing required content in national legislation, or by guidance listed by the NRA), while there are 3 MS which do not provide any form of common structure.
- For 9 MS harmonisation between DSOs is not (or less) applicable, as there is only 1 main DSO present. In 2 of these MS still guidance on a common structure is provided.

	Common use of structure	Comment
AT	Template available	
BE	-	
BG	Required content is listed and provided by NRA	
HR	Required content is listed in national legislation	
CY	-	
CZ	-	
DK	Template available	
EE	Template available	
FI	Required content is listed in national legislation	The three biggest DSOs also apply the same structure
FR	-	
DE	Required content is listed in national legislation	
GR	-	
HU	Required content is listed in national legislation	
IE	-	
IT	Required content is listed and provided by NRA	
LV	Required content is listed and provided by NRA	
LT	-	
LU	-	The NRA is working on a document with recommendations for DNDP creation, currently under private consultation, to be published
MT	-	
NL	Required content is listed in national legislation	
PL	Template available (to be used as of 2026)	For small DSOs (<100.000 customers) there is no template, but there are specific guidelines
PT	Template available	
RO	Required content is listed and provided by NRA	
SK	Required content is listed in national legislation	

SI	-	No template or common structure, but individual DSO plans are aggregated into a national-level NDP.[137]
ES	Required content is listed in national legislation	
SE	Template available	

4. Actionability

Note: Further details on capacity map information are provided in Topic 3 on grid connections

- In 22 MS capacity maps are available. However, these maps are not uniformly standardized across DSO(s) or TSO(s) within a MS, and even less so across different MS.
- In 19 MS investment lists / plans are available, albeit with varying levels of detail (i.e. in voltage levels).

	Capacity maps*	Investment lists / plans	Comment
AT	Yes	-	
BE	Yes	Yes (at least in Wallonia)	
BG	Yes	-	
HR	Yes	Yes	
CY	Yes	-	
CZ	Yes	Yes	
DK	Yes	Yes	Investment plans are split up on different voltage levels
EE	Yes	Yes	
FI	Yes	Yes	
FR	Yes	Yes	

[137] Slovenia has a unique structure. There is one Distribution System Operator (DSO) in the legal and functional sense for system operation, which is SODO d.o.o. However, the ownership and physical operation of the distribution network assets are still largely with five regional electricity distribution companies. SODO coordinates these 5 companies.

DE	Yes, but not standardised	-	Capacity maps are mandated by law but are not nationally standardized across DSOs
GR	Yes	-	
HU	-	Yes	No capacity maps exist, but allocated capacities for >0.5 MW RES power plants are published on the NRA's website to incentivise colocation. It is planned to create a map based on this list.
IE	Yes	-	
IT	Yes	Yes	
LV	Yes	Yes	
LT	-	Yes	Map visualising investment needing 10 kV and 35 kV network does exist (pages 14-15 of network development plan)
LU	-	Yes	Investment plans present concrete projects, costs, timeline and purpose and potentially Cost-Benefit Analysis for 110 kV and 65 kV levels, while for 20 kV identification of weak points takes place
MT	-	-	Information is not available as Enemalta has not made NDP publicly accessible.
NL	Yes	Yes	Geographical maps that visualise investments per region exist and NDP includes table with planned investments up until substation level
PL	Yes (only at TSO level)	-	
PT	Yes (only for HV and MV networks)	Yes	
RO	Yes	Yes	
SK	Yes	Yes, but not publicly available	DNDPs must contain several details regarding investment plans and costs, but these are hidden in the public versions of DNDPs.
SI	Yes	Yes	
ES	Yes	Yes	
SE	-	Yes	A ten-year investment plan that focuses on projects categorized into phases such as "under consideration," "preparatory," and "construction" is available

5. *Approval responsibility*

- In all MS the DNDPs are submitted to the NRA for approval.

	Approval by NRA	Comment
AT	Yes	
BE	Yes	
BG	Yes	DNDP also submitted to TSO
HR	Yes	
CY	Yes	
CZ	Yes	
DK	Yes	
EE	Yes	
FI	Yes	
FR	Yes	
DE	Yes	
GR	Yes	
HU	Yes	
IE	Yes	
IT	Yes	
LV	Yes	
LT	Yes	
LU	Yes	NRA has to approve the scenarios as well as the actual plan
MT	Yes	
NL	Yes	
PL	Yes	NRA in consultation with Minister for Energy
PT	Yes	Approval is responsibility of NRA; formal approval is done by the Council of Ministers by a resolution
RO	Yes	
SK	Yes	Also approval by the Ministry for Energy
SI	Yes	

ES	Yes	
SE	Yes	

6. *Stakeholder / transparency*

- DNDPs are publicly available in 24 MS, while they are not publicly available in 3 MS.
- In 5 MS full DNDPs are available in English, while in 2 MS summaries of key insights are provided in English
- In 22 MS public consultation of the (draft) DNDPs takes place, while in 5 MS public consultation does not take place.

	Public availability	Availability in English	Public consultation	Comment
AT	Yes	No	Yes	
BE	Yes	No	Yes	
BG	No	No	No	Only private consultation processes are involved in the NDP development. According to Article 6 of the Energy Act, DSOs have to provide information to municipalities upon request.
HR	Yes	No	Yes	
CY	Yes	No	Yes	
CZ	Yes	No	No	
DK	Yes	Summaries in English	Yes	
EE	Yes	No	Yes	
FI	Yes	No	Yes	
FR	Yes	Yes	Yes	
DE	Yes	No	Yes	
GR	Yes	No	Yes	

HU	Yes	No	Yes	
IE	Yes	Yes (national language)	Yes	
IT	Yes	No	Yes	
LV	Yes	No	Yes	
LT	Yes	No	Yes	
LU	Yes	Yes	Yes	
MT	No	Yes	No	Documents from Enemalta (DSO) not found and not publicly available. Until 2024, Enemalta has failed to file a NDP in line with the requirements expressed in the national legislation (S.L. 545.34). The reporting requirement had not been enforced by the Regulator (REWS).
NL	Yes	No	Yes	
PL	Yes	No	Yes	
PT	Yes	No	Yes	
RO	Yes	No	Yes	By law it is obliged to make DNDPs publicly available, but in practice not all plans are actually available.
SK	Yes	No	No	Only non-public DSO-NRA consultation takes place during the development of the DNDP.
SI	Yes	Summaries in English	Yes	
ES	No	No	No	It is not mandatory to publish DNDPs, but some regional governments might decide to make it public
SE	Yes	Yes	Yes	

7. Application of withdrawal and injection charges by user group for DSO cost recovery

Abbreviations: E: energy-based, P: power-based, L: lump sum

	Charges for withdrawal			Charges for injection		
	Consumer	**Storage**	**Prosumer**	**Generation**	**Storage**	**Prosumer**
AT	E, P, L	PHES: E, P	E, P	E, L	PHES: E	E, P
BE	E, P, L	Brussels (PHES), Flanders (both), Wallonia (non-PHES): E, P	Brussels: E, L / E, P Flanders, Wallonia: E, P	Brussels: none Flanders: E Wallonia: P, L	Flanders (both): E Wallonia (non-PHES): P	Flanders: E Wallonia: P
BG	E, P	none	No information	none	-	E
HR	E, P, L	PHES: E, P, L	E, P, RE, L	none	-	-
CY	E	no storage facilities	E, P	none	-	-
CZ	E, P	PHES: E	E, P	none	-	-
DK	E, P, L	non-PHES: E, P, L	E, P, L	E, L	non-PHES: E, P, L	E
EE	E, P, L	no storage facilities	E, P, L	P, L	no storage facilities	P, L
FI	E, P, L	PHES: E, P, L	E, P, L	E, P, L	PHES: E, P, L	E, P, L
FR	E, P, L	Non-PHES: E, P, L	E, P, L	L	non-PHES: none	none
DE	E, P, L	Both: E, P	E, P	E (negative)	Both: E (negative)	E (negative)

GR	E, P	non-PHES: E, P	E, P	none	-	-
HU	E, P, L	non-PHES: E, P, L	E, P, L	none	-	-
IE	E, P, L	non-PHES: E, P	E, L	none	-	-
IT	E, P, L	Both: none	P	none	-	-
LV	E, P	no storage facilities	P	P	no storage facilities	P
LT	E, P, L	non-PHES: E	E	none	-	-
LU	E, P, L	no storage facilities	E, P / E, L	none	-	-
MT	E, P, L	non-PHES: E, P, L	E, P, L	L	non-PHES: none	none
NL	E, P, L	non-PHES: E, P, L	E, P, L	L	non-PHES: none	none
PL	E, P, L	Both: E, P, L	E, P, L	none	-	-
PT	E, P	Both: none	E, P	none	-	-
RO [138]	E	E	E	none		-
SK	E, P	Both: E, P	E, P	P	Both: P	P
SI	E, P	E, P	E, P	none	-	-
ES	E, P	Both: none	E, P	none	-	-
SE	E, P, L	Both: E, L	E, P, L	P	Both: P, L	no uniform practice

[138] The case of Romania is complex: injection tariffs are only for transmission costs, but are collected by the DSOs. The presentation in the tables leaves this out because the focus is on DSO cost recovery.

8. *Application of Time-of-Use network charges*

- Time-of-Use (ToU) network charges are applied in 20 MS. In 14 MS there is variation by season, in 11 MS variation by weekday, and in 19 MS variation by time of day. MS without ToU provisions are excluded from the Table.

	ToU component	Variation by season	Variation by weekday	Variation by time of day
AT	E	winter/summer	-	day/night
BE	Brussels, Flanders, Wallonia: E	Wallonia: yes	Brussels, Flanders, Wallonia: weekend/holiday	Brussels: day/night Flanders: night tariff for accumulation heating Wallonia: day/night
HR	E, P	different times for peak	-	peak/off-peak
CZ	E, P	-	weekend (low voltage)	peak/off-peak
DK	E	winter/summer	-	2-3 tiers
EE	E	peak tariffs Nov-Mar	weekend/holiday	day/night + optional peak
FI	E, P	winter/summer	-	day/night
FR	E, P	winter/summer	-	peak/off-peak
DE	E (only interruptible load low V.)	yes, dependent on DSO	-	peak/half-peak/off-peak
GR	P (capacity charge)	yes	-	-
IE	E	-	-	day/night, peak
LT	E	-	weekend	day/night
MT	E	-	Sunday for EV charging	day/night, peak/off-peak for EV charging
NL	E	-	weekend	day/night
PL	E	summer/winter	weekend/holiday	peak/off-peak
PT	E, P	summer/winter	weekend	peak/half-peak/off-peak/super-off-peak
SK	E	-	weekend	peak/off-peak
SI	E	summer/winter	weekend/holiday	peak/off-peak, 5 time blocks
ES	E, P	4 seasons	weekend	6 periods for power-based charge (2 for households); 6 periods for energy-based

				charge (3 for households)
SE	E, P	summer/winter (optional)	-	peak/off-peak (optional)

9. Application of connection charges

- Both shallow and deep connection charges are applied in 11 MS. 5 MS only apply deep connection charges and 11 MS only shallow connection charges.

	Main design: deep/shallow	Locational signal
AT	shallow	network areas
BE	all: deep	Wallonia: differentiation between rural and urban areas
BG	shallow	no
HR	deep	yes
CY	shallow	yes (charge increases with distance from network)
CZ	shallow	differentiation between rural and urban areas
DK	shallow and deep	for producers
EE	shallow and deep	no
FI	shallow and deep	zone, area and case by case pricing
FR	shallow	regional schemes for mutualizing RES connection fees
DE	shallow and deep	-
GR	shallow and deep	yes
HU	shallow and deep	no
IE	shallow	-
IT	shallow	no
LV	shallow and deep	no
LT	shallow and deep	no
LU	shallow	yes
MT	shallow and deep	no

NL	shallow	no
PL	shallow	differences between DSOs
PT	deep	no
RO	shallow and deep	no
SK	shallow and deep	-
SI	shallow	no
ES	deep	no
SE	deep	calculated individually

10. Treatment of prosumers and storage regarding withdrawal, injection, and connection charges

	Prosumers	Storage
AT	no injection charge for < 5MW	reduced withdrawal and injection charges for PHES
BE	Brussels: no exemptions Flanders: no injection charges for < 10kW, energy-based and power-based charges in case of smart meter, else energy-based, lump sum and inverter power-based Wallonia: for < 10 kVA no injection charges, specific pricing; gross withdrawal with cap; MV/HV level: net withdrawal	Brussels, Flanders: no exemptions Wallonia: full exemption from taxes and surcharges on DSO tariffs, full exemption on TSO tariffs, except for reactive energy tariffs and own consumption, full exemption from injection charges
BG	no information	no exemptions
HR	household prosumers: net withdrawal (monthly), other: gross withdrawal; discount on charges for some household prosumers	only considered an "end customer" for own consumption
CY	net withdrawal (bi-monthly)	no withdrawal or injection charges
CZ	full exemption or discount from reserve capacity tariffs for some prosumers	not subject to power-based component
DK	no injection charges for some prosumers	no exemptions
EE	prosumers < 63A are exempted from power-based charges	no exemptions

FI	net metering (hourly), no injection charges for small producers in some DSO areas	no uniform practices amongst DSOs; in some DSO areas separate tariffs
FR	no injection charges	no exemptions
DE	negative injection charges	full exemptions for some PHES; Non-PHES: full exemption for withdrawal charges for stored energy for first 20 years of operation for storage facilities commissioned between 2011 and 2029 + negative injection charge
GR	no exemptions	No exemptions
HU	net metering for prosumers with < 50kW generation (yearly <3x80A, monthly >3x80A, only for connections before 09/2023 applied for 10 years from installation); household prosumers < 50kVA do not pay connection charges	no exemptions for withdrawal and injection charges; differentiation in connection charges
IE	no injection charges for distribution costs, no withdrawal charges for prosumers with generation capacity not higher than consumption	no injection charges
IT	no exemptions	No withdrawal charges for charging
LV	no capacity charge for injection in case of generation capacity not higher than consumption	no information
LT	no energy-based component; differentiations for household and non-household prosumers; net metering; 50% discount on connection charge	exemptions for batteries: < 1MW: no withdrawal or injection charges, > 1MW: no withdrawal charges for charging; connection charges: 50% discount for batteries that are consumption only
LU	net metering (quarter hourly) for energy-based component of withdrawal charges	no exemptions
MT	no injection charges	no exemptions
NL	no administrative fee for injection	no administrative fee for injection
PL	exemptions for prosumers connected before April 2022; no exemptions for newly connected prosumers	special rules: reduced fixed capacity charge & energy-based charge for withdrawal; 50% discount for connection charges
PT	no exemptions	no withdrawal or injection tariffs for bidirectional storage facilities. Intermediate consumption is exempted from withdrawal cost (no double charging).
RO	prosumers < 5MW: exemption from injection charges (transmission)	< 5MW: exemption from transmission injection charges
SK	differentiation in withdrawal charges, exemptions for some prosumers ("local	No charges for storage that only provides ancillary services; full exemption for operators of hydroelectric power plants up to 5MW; for others: charge for connection

	sources"), total exemptions in case of ancillary service provision	capacity based on injection or withdrawal (higher one counts);
SI	net metering (yearly) of energy-based component for < 43kW; gross metering above	no exemptions
ES	no exemptions	no withdrawal or injection charges
SE	injection charges only in case of production higher than consumption for prosumers > 63A and 43.5kW; net metering for some prosumers (15 minutes)	some exemptions in some DSO areas, no uniform practices

11.Composition and adjustment of regulatory asset base (RAB)

	RAB components	**RAB adjustment**
AT	Intangible and fixed assets, book values; anticipated developments are considered	RAB developments during a RP are considered, lead to changes of the regulated cost base
BE	VREG: Intangible and tangible fixed assets (including assets under construction, excluding goodwill) BRUGEL: Fixed assets, assets under construction	VREG: - BRUGEL: Investments (+), divestments (-), depreciation (-), subsidies (-)
BG	Book value, amortization, any assets acquired through financing from EU or other public funds is excluded from the RAB, investments have to be justifiable with current needs and projects	Adjustments based on fulfilment of investment program
HR	Asset base includes average value of regulated assets in the beginning of the year and at the end and excludes value of assets received without charge, financed by grants.	No adjustment
CY	Depreciated fixed assets, working capital	- New investments - only upon approval by the regulator; - annual RAB adjustment if CAPEX is lower than what was approved as part of the required income
CZ	Fixed assets, investments in progress [assets under construction if the planned acquisition period is more than two years (excl. preparation time) and planned value exceeds 500 million CZK in the relevant year], leased assets, no working capital	Adjustment based on time value of money

DK	All assets related to licensed activity of a DSO, working capital and assets under construction; intangible items (e.g. IT systems) may be included if they serve DSO functions; new regulation allows for "green" investment	Adjusted for non-controllable costs; adjustments for changes in the price levels (inflation) and the specific activity level of a given DSO
EE	Fixed assets, working capital [5% of the allowed revenue of the tariff year], leased assets "Fixed assets do not include long-term financial investments, intangible assets (except for software licenses), fixed assets acquired with grant aid (including targeted funding), fixed assets acquired with funds obtained from connection fees, or fixed assets that the undertaking does not use for the purpose of providing network services".	N/A
FI	Fixed assets, working capital, leased assets; no formal definition for anticipatory investment but network development is based on long-term, need-based planning	Inflation adjustment using the average consumer price index
FR	Fixed assets; Subsidies and grants are removed from the value of assets before entering the RAB.	N/A
DE	Fixed assets, working capital, assets under construction; anticipatory investments in asset base not restricted by regulation, however lacking definition imposes risk for DSOs	Investments in new assets after the base year led to an adjustment of CAPEX. No distinction between replacements and enhancements or expansions
GR	Fixed assets, working capital, assets under construction	No adjustments, historical values; ex-post treatment of CAPEX
HU	Fixed assets	t-1 year's investments are considered (after subtracting depreciation and connection charges) The annual network tariff adjustment formula accounts for WACC, inflation (CPI) and wage indices, new investments, forward electricity price changes for network losses, differences between actual and forecasted revenue
IE	Fixed assets, assets under construction	"Assets are added to the RAB as the costs are incurred. If an asset has not been energised within five years (unless works are scheduled to be longer than five years or the DSO can show that the delay is beyond their control), the asset is temporarily removed from the RAB" until energised and used. Further adjustments with uncertainty mechanism, further flexibility mechanism and innovation and R&D mechanism

IT	Fixed assets, working capital, assets under construction	Adjustment annually based on performance incentives such as OPEX efficiency improvement, quality of supply and network resilience by rewards and penalties
LV	Fixed assets, intangible investment. Does not include inventories and assets under construction With regard to anticipatory investments, tariffs are based on justified historical costs and forecast of any other future costs (taking into account official forecast of inflation)	Yearly WACC adjustment but no RAB adjustment
LT	Fixed assets	Regulated price caps are adjusted each year for new investments, depreciation and change of WACC (CAPEX)
LU	Fixed assets containing production costs, work in progress	Annual review of the maximum allowed revenue, RAB remuneration, work in progress remuneration, depreciation, quantity factor and indexes for controllable costs and specific pass-through items will be adjusted
MT	N/A	N/A
NL	Fixed assets and certain intangible assets (such as software) are included, no working capital	Annual indexation (in the current RP: with half of the CPI). Adjustment for certain specific (expansionary) investments
PL	Fixed assets, assets under construction, intangible assets	Annually
PT	Fixed assets net of third parties' contributions; Investments included in the DNDP are taken into account	"RAB does not adjust automatically every year due to the revenue cap on TOTEX. However, the profit/loss sharing mechanism calculated after the end of the regulatory period considers the annual real RAB adjusted for new investments, write-offs and depreciation". RoR updated ex-post each year; the WACC (pre-tax) applied in the RP is indexed on the Portuguese ten-year bond benchmark and depends on its evolution with a cap and a floor. The allowed revenues from each activity are adjusted after two years based on real, audited values. Adjustments are incorporated into allowed revenues of the year with the appropriate financial update.
RO	Fixed assets, except contributions from third parties	Annual adjustments based on inflation, investment, OPEX
SK	Fixed assets, no working capital	"No RAB adjustment takes place during the RP". In the event of a significant change in the economic parameters based on which URSO approved or set the price, the regulated

		entity may request an amendment in the price decision. URSO may also initiate a change in the price decision on its own initiative.
SI	Book values of tangible and intangible assets after RAB adjustment, ex ante investments according to development plan, no working capital, no assets under construction	Addition of new approved CAPEX (investments) at book values.
ES	Fixed assets (no working capital, no assets under construction)	"Assets built year n-2 are added year n"; RAB is updated every year, by adding new investments and subtracting depreciation.
SE	Fixed assets divided into lines, cables, buildings, shunt reactors, transformers, switchgear, stations, cable cabinet, control-equipment, meters and IT-system (not assets under construction)	Adjusted for inflation, adjustments ex post for new investments and disposals

12.RAB-related regulatory features incentivizing innovative grid measures

Note: Aspects related to the use of innovative grid measures from digitalization/smart grids are highlighted in bold.

Preliminary consideration: Smart grid solutions are characterised by their digital, data-driven, and service-oriented nature. While increasing OPEX, they tend to reduce the need for (or extend the useful life) of fixed assets. The traditional approach of calculating the DSO return allowance based on the CAPEX may discourage OPEX-driven investments. Accordingly, an overview is provided below on how OPEX are treated in the DSO regulation. In addition, any specific incentives for smart grid measures that were identified in individual MS are thus highlighted.

	Treatment of investment and OPEX, including innovative grid measures (e.g. digitalization, smart grids solutions, demand response)
AT	OPEX adjusted based on price index, general productivity index and individual efficiency factor during regulation period CAPEX adjusted annually based on efficiency-dependent return and encouraged during regulation period by mark-up on WACC
BE	VREG: Operating costs, depreciation and return on assets are included as part of the endogenous costs, and for exogenous costs a baseline is determined that aggregates allowed operating and capital costs, subject to annual inflation
BG	For defining the OPEX for the first year of regulatory period are considered cost for the base year. For the following years, costs are calculated with indexation with inflation.
HR	As OPEX are included: costs of network maintenance, costs of loss coverage in the network, costs of gross salaries, other staff costs, other business-related costs; revenue should cover OPEX and CAPEX.
CY	Split into controllable and non-controllable OPEX

CZ	Incentive regulation (revenue cap) with yardstick benchmark; other elements: eligible costs, eligible depreciation and amortisation, RAB (fixed assets, investments in progress, leased assets, no working capital), WACC
DK	Both CAPEX (grid expansion, cables, substations) and OPEX (maintenance, overhead) are recognized, subject to regulator's efficiency checks.
EE	N/A
FI	Cost-effectiveness in both operational expenditures (OPEX) and network development. OPEX is regulated through pricing and the collection of unit prices serves as a form of scrutiny; efficiency, quality, **innovation, and investment incentives** are considered with changing regulation methods at the beginning of the regulation period
FR	N/A
DE	OPEX (non-controllable and controllable costs); TOTEX efficiency comparison
GR	OPEX (non-controllable and controllable costs), depreciation, RAB (assets and approved investment plans, working capital), WACC and WACC premium
HU	CAPEX and OPEX (including **flexibility services**)
IE	CAPEX and OPEX with flexibility mechanism that allows the DSO to reallocate allowances between OPEX and CAPEX (bi-directional); other performance incentives associated with continuity of supply, estimated restoration time accuracy, customer satisfaction, **smart metering**, stakeholder engagement, worst-served customer, timely issuing of connection offers, **visibility**, flexibility, DSO/TSO coordination, and independent role of the DSO
IT	New investments, depreciation, grants. For standard costs, changes in the driver
LV	Includes CAPEX and OPEX
LT	Considers TOTEX with OPEX and CAPEX
LU	Revenue cap based on value of regulated assets, WACC, depreciation, operating expenses
MT	N/A
NL	CAPEX, OPEX and WACC. **Software** is included in RAB.
PL	N/A
PT	TOTEX with operating costs (net of additional income), controllable and non-controllable costs and investment costs
RO	TOTEX with controllable and non-controllable costs and investment costs
SK	Costs associated with **innovative grid measures** are considered eligible for inclusion in the RAB (fixed assets, no working capital). WACC mechanism provides stable returns on RAB investments. Efficiency factor applied to controllable OPEX.
SI	Controllable OPEX (efficiency score, general productivity), uncontrollable OPEX, CAPEX (depreciation, regulated return on assets)
ES	Remuneration for investment, OPEX, extended lifetime of assets, cost of other regulated tasks (metering, invoicing, grid planning, etc.) which are set according to reference values, calculated with the number of clients (providing **incentives for efficient operation**) and quality incentives.

SE	TOTEX with meters and **IT systems** included in RAB

13.Capacity maps

- 22 of 27 countries provide some form of capacity map
- In 17 countries, the provided maps cover the entire national territory; in 4 countries, coverage is at the DSO level, and in 1 country at the TSO level. Some overlap between national and DSO-level coverage may occur, as certain countries have only one DSO.
- Available capacity is typically displayed either as a list of substations with their corresponding free capacity or through a color-coded categorization system.

	Level **- Country** **- DSO** **- Other**	**Type** **-Map** **- List of (sub)stations/transmission lines** **- Other**	**Indicator** **- Quantitative** **- Traffic light system** **- Other**	**Link**
AT	Country	Map displaying the locations of substations, including details on the region, grid operator, and both booked and available capacity. Additionally, a list is provided for each DSO, outlining their respective substations including the update date.	Quantitative: Booked and available capacity in MVA, as legally required under §20(1) ElWOG.	https://www.ebutilities.at/verfuegbare-netzanschlusskapazitaeten
BE	Country	Geographic overview by substation or zone, for a selected target year, grid user type (load, generation, storage), and flexibility level (defined by allowed energy curtailment).	Estimates the additional MW that can be hosted at a single location—based on assumptions such as planned infrastructure, reserved capacity, and connection criteria—without requiring grid reinforcements. Does not account for constraints like short-circuit currents, voltage limits, or spatial constraints.	https://www.elia.be/en/customers/connection/grid-hosting-capacity
BG	Country	A single interface allows users to search by area unit or region to check for available capacity, specifically for RES producers. Additionally, a map with transmission lines and substations indicates available capacity per substation.	Capacity availability is presented on a binary yes/no basis, while the map additionally displays the remaining capacity as a quantitative value for each location.	https://ermzapad.bg/bg/za-klienta/uslugi/prisedinyavaniya/proverka-za-nalichie-na-kapacitet-na-erm-zapad-za-vei-proizvoditeli/ https://webap

				ps.eso.bg/capacity/
CY	Country	A comprehensive map and list of all substations are provided, including detailed information on both total and available capacity at each substation. Additionally, data on the capacity of connected RES is included, categorized by type.	Quantitative and colour categorization.	https://www.arcgis.com/apps/dashboards/134fdd8988d44ade8dd33b5c1c26ca65
CZ	DSO	Data is displayed by voltage level (low V., HV, VHV) and includes information on applications within the specified area.	The likelihood of available capacity for connecting a production plant is indicated using a color-coded system. Additionally, available distribution capacity on 110 kV lines and 110 kV/HV distribution transformers is provided.	https://www.cezdistribuce.cz/cs/distribucni-soustava/volna-distribucni-kapacita https://www.cezdistribuce.cz/cs/pro-vyrobce/volna-distribucni-kapacita-pro-pripojovani-vyroben
DE	Country/DSO	The development of a common DSO platform is currently underway and legally required (§14e EnWG). At present, the platform only allows users to identify their grid operator and access a link to the operator's website. Some DSO provide information about available capacity in their respective grid area.	N/A	https://www.vnbdigital.de/ https://www.stromnetz.berlin/anschliessen/anschluss-mittel-hochspannung/repartierung/ https://snap.mitnetz-strom.de/ https://netzanschlusspruefung.westnetz.de/public/occ/form?lang=de
DK	Country	The map provides an overview of the estimated available capacity within the 50–60 kV distribution network and the 132–150 kV transmission network for the connection and integration of new power generation assets. The maps depict power lines	Colour categorization.	https://storymaps.arcgis.com/stories/eb5b387e376f49b8996d5e7c47fbdd37

		across various voltage levels and use colour coding to indicate the available capacity in different regions.		
EE	DSO	Map displaying medium voltage power lines.	Colour categorization.	https://elektrilevi.ee/en/liitumised/vabad-voimsused https://vla.elering.ee/
ES	DSO	i-DE offers online tools that allow users to identify their grid operator. Like e-distribucion, they offer access to a map displaying substations along with their available capacities.	Colour categorization and quantitative.	https://www.i-de.es/grid-connection/energy-generation/capacity-map https://www.edistribucion.com/en/red-electrica/Nodos_capacidad_acceso.html
FI	Country	Map provides an overview of Fingrid's and its customers' existing grid (≥110 kV), along with planned projects and their development stages. Project details are based on available data, and locations are indicative. The map supports regional planning by visualizing estimated grid connectivity for future production and consumption.	N/A	https://www.fingrid.fi/en/grid/grid-connection-agreement-phases/grid-scope/
FR	Country	Map of available connection capacity for battery storages per substation.	Colour and quantitative.	https://analysesetdonnees.rte-france.com/reseaux/cartostock
GR	Country	The power absorption capability of RES stations in the Interconnected Network is presented in a list by geographical area, detailing substation and transformer data, RES capacity, thermal and short-cycle margins, and availability by	Quantitative; Traffic Light	https://apps.deddie.gr/WebAPE/main.html#

		municipality and regional directorate.		
HR	Country	Map-based tool displaying technical data relevant to the development of renewable energy projects, focused on the 110/x kV distribution grid level.	The map indicates the name and coordinates of each transformer substation, the installed transformer capacity (in MVA), and the available capacity, classified according to DSO-defined categories A-D.	https://www.gridone.hr/en/map/
HU	N/A	N/A	N/A	N/A
IE	Country	Interactive heatmap tool showing available transformer capacity at substations across different voltage levels (Low V., MV, HV), with separate views for demand and generation. Includes filtering by voltage level, capacity range, and other parameters.	Colour-coded visualization indicating the network's ability to support new demand connections or integrate large-scale generation, based on current available capacity.	https://www.esbnetworks.ie/services/get-connected/renewable-connection/network-capacity-heatmap
IT	Country	Interactive Critical Areas map for prospective producers to assess distribution network connection feasibility. It provides a territorial classification by network criticality level, with features like zooming, provincial selection, and color-coded saturation levels.	Network criticality is shown using colours. Users can also access detailed lists by province, including critical or non-concessionaire municipalities, HV/MV sections with flow reversal, and saturation levels per municipality.	https://www.e-distribuzione.it/a-chi-ci-rivolgiamo/produttori/aree-critiche.html?idMappa=f09ed9f7e46244d38a58551bfe2164a0
LT	N/A	N/A	N/A	N/A
LU	N/A	N/A	N/A	N/A
LV	Country	Map displaying various categories, including available capacity at substations, power line construction and maintenance, as well as cost calculations for new connections. Additionally, AST (TSO) provides a map for connections to the transmission grid.	Quantitative: E.g. free consumption and generation capacity in MW or connections costs in €.	https://karte.sadalestikls.lv/lv/atslegumi-elektrotikla https://www.ast.lv/en/content/connections-transmission-grid
MT	N/A	N/A	N/A	N/A
NL	Country	National electricity grid capacity map composed of layered views: an	Displays real-time indicative data on available transport capacity, congestion status,	https://data.partnersinenergie.nl/capacit

		overview of congestion, a TenneT high-voltage layer, and regional grid operator layers (medium voltage). It is interactive and publicly accessible, offering views for both offtake and feed-in.	contract queue information, and planned grid expansions. Includes network operator logos with direct website links and tools to identify the relevant operator.	eitskaart/totaal/afname
PL	TSO	List of substations and groups of substations owned by PSE S.A.; pdf file.	Quantitative	https://www.pse.pl/obszary-dzialalnosci/krajowy-system-elektroenergetyczny/informacja-o-dostepnosci-mocy-przylaczeniowej
PT	Country	Geographic visualization of HV/MV substations showing their areas of influence along MV lines, with quarterly updates and forecasts of hosting capacity for power generation in the distribution grid.	For each HV/MV substation, hosting capacity is assessed based on existing or compromised electricity production centres connected to the high and medium voltage buses.	https://e-redes.opendatasoft.com/pages/capacidadees/capacidade_rececao_rnd/
RO	Country	The map displays 10 zones alongside the 110 kV transmission grid and interconnections, with availability data provided for multiple years.	Quantitative and colour categorization.	https://web.transelectrica.ro/harti_crd_tel/
SE	N/A	N/A	N/A	N/A
SI	Country	SODO Kart provides a geographical overview of possible connection points in terms of the potential of the existing network to connect larger generation installations (over 50 kW) directly to the existing electricity distribution network. This does not include the connection of individual self-supply generating installations which are connected to	Quantitative and colour categorization.	https://www.eles.si/en/res-hosting-capacity-of-slovenian-transmission-network https://www.sodo.si/sl/o-omrezju/sodokart

		the internal network of the system users.		
SK	Country	Overview of total and free installed generation capacity in three major distribution systems, categorized by energy source, in accordance with grid connection allocation rules (Chapter S4, Document S).	Quantitative	Installed power | Slovak electricity transmission system, Plc.

14.Flexible connection agreements

Note: The data on flexible connection agreements are not complete for all 27 MS. N/A thus indicates that data is not available in the table below.

- At least 10 countries have some form of flexible connection agreement already implemented
- In 5 countries flexible connection agreements are being tested or prepared for adoption by legal acts

	Time Limit - Unlimited/Limited - Legislative Basis	**Reduction of Network Costs - Yes/No**	**Incentives (Administrative/Financial) - Yes/No/Partially**
AT	Limited. No explicit legislative basis; indirectly derived from the obligation to connect (§46 ElWOG). Refer to Processing time for connection requests.	No	No
BE	Region of Wallonia demands the possibility of modulating injection capacity for assets > 250 kVA if the DSO requires it.	N/A	N/A
BG	N/A	N/A	N/A
CY	N/A	N/A	N/A
CZ	The Lex RES 3 prepares the ground for flexible connection agreements by introducing legal and technical frameworks, but the specific rules and tools for their implementation are not yet finalized.	N/A	N/A
DE	Yes, §17 EnWG and §8a EEG. §14a also allows dimming of actual load on a specified minimum in return for reduced network costs.	Yes for §14a.	N/A

DK	DSO offer FCAs if customer accepts partial curtailment within constrained periods of time	Yes	N/A
EE	N/A	N/A	N/A
ES	No regulatory framework exists yet; it is under elaboration.	N/A	N/A
FI	Additional service agreement or tariff allowing the DSO to adjust connection operation.	No	No
FR	Flexible connections are already used for DER producers, particularly at the transmission level, and regulatory sandboxes are enabling DSOs to test such connections. The legal framework permits non-firm connections in three cases: anticipated connections with temporary power modulation, alternative offers that reduce connection costs with limited uncompensated curtailment, and intelligent offers allowing connections at saturated substations with compensated curtailment. These mechanisms aim to facilitate DER integration while managing grid constraints and investment.	N/A	N/A
GR	N/A	N/A	N/A
HR	Interim solution with clearly defined duration.	N/A	N/A
HU	Regulatory codes allow for non-firm capacity contracts, but only for a limited circle of system users (new power plants and storage providers) and for a fixed purpose (economic efficiency). DSOs can design the contracts with some leeway, but data on these arrangements is barely shared.	N/A	N/A
IE	N/A	N/A	N/A
IT	N/A	N/A	N/A
LT	N/A	N/A	N/A
LU	N/A	N/A	N/A
LV	N/A	N/A	N/A
MT	N/A	N/A	N/A

NL	Limited until the completion of grid expansion works in the congestion area.	Yes	Compensation options include a fixed monthly fee for asset availability, a call-out fee per day of activation, payment per curtailed MWh, and reimbursement for missed SDE subsidies and Guarantees of Origin (GvOs), calculated retrospectively.
PL	N/A	N/A	N/A
PT	Decreto-Lei 15/2022 provides for the allocation of 'capacity with restrictions', which shall be proposed by grid operators, and implemented through a Restricted Access Agreement. The general conditions for these agreements are specified by Diretiva n. º 3/2025. Terms are agreed between the parties in the injection capacity reservation title.	No empirical data are yet available	The regulatory framework facilitates the solution to encourage faster grid connection (Decreto-Lei 15/2022)
RO	From June 2025, new Romanian grid connection permits will include "Operational Limitations" allowing the grid operator to curtail power output, even to zero, during congestion to ensure grid stability (ANRE Order 20/2025).	N/A	N/A
SE	No explicit restriction on use of flexible connection agreements.	N/A	N/A
SI	The government has adopted a proposal to amend the Electricity Supply Act, introducing flexible grid connection options. Adopted on March 27, 2025, the Act is not yet in force, pending parliamentary approval and official publication.	N/A	N/A
SK	Not yet available, expected to change from 1st of July 2025 or 1st of January 2026.	N/A	N/A

15.Treatment of grid connection requests

- Almost all countries apply the first-come, first-served principle for grid connections.
- Exceptions exist in some countries, where, for example, prioritization is based on strategic projects (GR), added social value (ES), technical considerations for safe and efficient grid operation (NL), or the promotion of small-scale assets (SI).

	Method/Principle - First-Come-First-Serve - Prioritization (How)
AT	First-Come-First-Serve
BE	N/A
BG	First-Come-First-Serve DSOs shall indicate the reasons for the refusal and the necessary measures to eliminate them, including ensuring conditions for connecting the facility, in accordance with the network development plans and a timeframe to address them
CY	First-Come-First-Serve. The primary priority in assigning grid capacity is to ensure the reliability of the network. Subsequently, priority is granted to existing users to maintain a stable electricity supply. Additionally, connections critical to public services, such as hospitals, are given special priority.
CZ	First-Come-First-Serve
DE	There is an obligation to connect in a transparent and non-discriminatory manner; however, no detailed specifications or prioritization procedures have been established to date (EnWG §17 (1)).
DK	First-Come-First-Serve
EE	First-Come-First-Serve
ES	First-Come-First-Serve. In some cases, the social value of the project may be considered.
FI	N/A
FR	There is an obligation to connect in a transparent and non-discriminatory manner (Article L342-12). First-Come-First-Serve. However, RES production requests may be prioritized under Article 15 of the law for the acceleration of RES development, provided they are located within priority zones (S3REnR) for RES development designated by the TSO.
GR	First-Come-First-Serve. Adjustments for critical infrastructure and strategic projects.
HR	N/A
HU	Until 2025, the pro rata principle applies, with prioritization given to connections to the medium-voltage (MV) network and larger plants (excluding small-scale power plants). From 2025 onwards (planned), grid connections will be allocated through a tender process organized by the NRA, based on connection points and years. Award decisions will follow criteria established by the Ministry of Energy. This process is not an auction; successful tenderers may submit connection requests to the DSO, with connection charges remaining cost-reflective. Connection charges will consist of shallow and deep connection fees determined on an individual basis.
IE	First-Come-First-Serve for small-scale generation (≤ 200 kVA). Assignment conducted in batches for larger generation sites, e.g. group processing of generator applications.
IT	The process comprises the following stages: Application and Evaluation, Capacity Assessment, and Priority Criteria. Priority for connection requests at the distribution level is accorded to (1) projects that facilitate the integration of renewable energy sources (RES), electric vehicles (EVs), and other sustainable technologies in alignment with energy transition objectives, and (2) the requirements of the transmission grid.
LT	First-Come-First-Serve

LU	First-Come-First-Serve
LV	First-Come-First-Serve
MT	First-Come-First-Serve
NL	First-Come-First-Serve. In congested areas, DSOs may apply a priority framework based on three domains: (1) congestion relievers, (2) safety, and (3) basic needs. Attempts to introduce a comprehensive prioritization framework based on social impacts were recently rejected in court.
PL	First-Come-First-Serve. New rules for cable pooling may undermine this strict principle.
PT	Three types of access are distinguished: (1) general access, granted on a first-come, first-served basis for installations intended for self-consumption; (2) access granted pursuant to an agreement with the grid operator, whereby the producer assumes responsibility for connection and grid reinforcement costs; and (3) access allocated through a competitive procedure, with an indicative schedule published by DGEG every three to five years.
RO	First-Come-First-Serve. Effective from 2026, the allocation of electricity network capacity for the connection of electricity production facilities with an installed capacity equal to or exceeding 5 MW shall be conducted through an auction process.
SE	First-Come-First-Serve. However, there is an ongoing recommendation to prioritize allocation for mature projects.
SI	First-Come-First-Serve. Small-scale producers and critical loads may receive prioritization.
SK	First-Come-First-Serve

16.Processing time for grid connection requests

- At least 15 MS have had initial experience of queue problems.

	Queue (definition: regular exceeding of legislative/formal process deadlines in general) Problems Existing - Yes/No + comments	**Legislative Deadlines - Max. processing time**
AT	No. In some cases, operational restrictions may occur despite of an existing grid connection. For example, only self-generated power may be permitted temporarily until the grid reinforcement measures are completed.	The obligation to connect also applies if grid expansion is needed (§46(2) ElWOG). Commissioning is required be completed within a maximum of 1 year for low and medium voltage levels. For high voltage and the transformation stage between high and medium voltage, the period must not exceed 3 years (§46(4) ElWOG). Small RES units ≤ 20 kW must be connected within 4 weeks (§17a (3) ElWOG).
BE	Yes, but mainly locally and for specific industrial connections like data centres or storage (reported for Flanders).	For low voltage connections, the DSO must issue a proposal within 10 calendar days in Wallonia and within 5 working days in Flanders. The connection is generally required to be completed within 15 working days thereafter. In Flanders, if the DSO exceeds the prescribed lead time, it must pay a penalty fee to the applicant,

		ranging from €25 to €100 per day depending on the type of connection.
BG	N/A	DSOs shall establish the conditions and provide a written opinion regarding the connection to the applicant within 14 days; this period may be extended to 30 days if additional documentation is requested.
CY	Yes, delays reported for solar generation.	6-12 months depending on connection type.
CZ	Yes, delays reported for solar generation.	The minimum timeframe from the submission of a network connection request to the issuance of a draft contract is 30 days. However, the overall process may be significantly extended if the DSO/TSO requires the submission of a detailed connection plan.
DE	Minor local issues reported, with individual DSOs introducing local mechanisms to cope.	A maximum processing time of two months for DSOs has been proposed. This deadline is not established by law (§17 EnWG) but is defined by the NRA.
DK	Yes, mainly originating from transmission level issues and mainly affecting generations.	No strict, universally defined deadline for providing a grid connection. Timelines vary significantly depending on the size of the project and the extent of grid reinforcement required. For small size connections grid access may be completed within a few weeks, provided no major infrastructure upgrades are needed. In contrast, complex connections involving large-scale projects, new transformers, or coordination with the TSO may take several months to years.
EE	N/A	The maximum processing times for connection requests are as follows: up to 0.79 kW, 4 business days; up to 15 kW, 30 calendar days; and for capacities above 15 kW, up to 340 calendar days.
ES	Yes, but with strong regional differences. Issues with the queue are driven by permitting wait times.	For connection points at a voltage level below 1 kV, if the requested capacity is up to 15 kW and no network extension is required, the maximum processing time is five days; in all other cases, it is 15 days. For connection points to the distribution network between 1 kV and 36 kV, the maximum processing time is 30 days; for connections above 36 kV, it is 40 days; and for higher voltage levels, up to 60 days.
FI	N/A	N/A
FR	No known issues with queue, but efforts to reform permitting to reduce backlog are under discussion.	According to Article L342-8 of the Energy Code, the connection of a renewable electricity generating facility with an installed capacity of 3 kVA or less must be completed within one month from the date the applicant accepts the connection agreement. For other renewable electricity generation installations, the connection period shall not exceed 12 months, unless duly justified exceptional circumstances apply. Additionally, under Article L342-9, the connection of EV charging stations must be carried out within a maximum of six months.
GR	Yes, especially for small-scale PV. More favourable treatment for community energy projects. Grid expansion would be needed	The timeframe for obtaining a grid connection varies depending on the type and complexity of the request. For residential and medium-sized commercial users, the process can take up to six months, provided no major

	to resolve the queue. There is discontent with the financial risk for delays falling on applicants/investors.	infrastructure upgrades are necessary. For larger connections, the lead time may extend up to two years. Additional delays may occur if the connection request requires further approvals or coordination with local authorities.
HR	N/A	In the case of a simple procedure, the connection process must be completed within 15 days. For complex procedures, the timeframe ranges from 30 days to 12 months, depending on the type and installed capacity of the asset.
HU	Yes, especially generation. Reform to align grid connections with NECP is under way.	30 days is the stated period for administrative procedure. Reported figures are up two years if grid investments are required (Eurelectric, 2025).
IE	Yes, issues at transmission level affect also distribution level capacity. Speculative connection requests and limited control procedures contribute to queue.	Requests are batch processed, but the assignment process and deadlines are subject to change relatively frequently.
IT	Currently little grid scarcity but expected with increasing decentralized generation. Administrative issues arise with long reservation periods; these processes are subject to review.	The maximum lead time for processing grid connection requests depends on the type of connection. For residential connections under 10 kV, the standard processing time is 20 days, with a maximum of 30 days allowed for the physical construction of the connection. For simple medium-voltage (MV) connections, the timeframe extends to 40–60 days, while more complex MV connections may require 90–120 days to complete.
LT	N/A	Can take 3 months or longer.
LU	N/A	Deadlines exist for the DSO's response, with a maximum processing time of three weeks for photovoltaic (PV) connection requests.
LV	N/A	60 days.
MT	N/A	16-36 working days.
NL	Yes, both in generation and consumption. Reform to prioritize based on societal impact was rejected in recent court decision. Process to revise prioritization framework is ongoing.	The maximum lead time for processing new connection requests of less than 3 × 80 A is 18 weeks from the date of the connection request. For requests exceeding 3 × 80 A, the maximum lead times vary depending on the complexity of the connection and may be subject to a 'dynamic regional waiting time' mechanism.
PL	Yes. Significant problems with a high number of rejected connection requests, primarily caused by inconsistent and unclear application conditions and processes. This results in uncertainty, speculative applications, and the blocking of grid connection rights.	The issuance of connection conditions depends on the voltage level of the network to which the investor seeks to connect and occurs within 14 days, 30 days, or up to 3 months from the submission of a complete application. The process is frequently extended due to requests for additional information until the application is deemed complete.
PT	N/A	Timelines vary according to the type of installation, with clear and transparent deadlines established. Applications submitted via the DGEG electronic platform must receive a

		response within 5 days, provided there are no restrictions, along with notification of the reserved injection capacity. If the grid operator issues a positive opinion, the injection capacity reserve title is granted within 10 days. For other types of applications, interested parties may request a cost estimate for the grid connection from the relevant grid operator within 30 days.
RO	Yes, backlog exists especially for generation and at multiple stages of the process. Division of responsibility for the queue between TSO and DSO is complex, as it depends on the size of the connection request. New auction system is being organized for larger generations (expected July 2025).	The deadlines for each step are as follows: 10 working days for the evaluation of submitted documentation; an additional 30 calendar days for establishing the connection solution and issuing the Technical Connection Permit (ATR); and up to 90 calendar days for the design and execution of the connection installation for households, or 30 calendar days for producers.
SE	Yes, with regional disbalance being a major driver. Issues are more prominent in the transmission grid but also acknowledged for distribution grids.	The law mandates that grid connections be completed within a "reasonable time," generally targeted to be under two years unless significant network reinforcements are required. However, "special reasons" may lead to substantial extensions. Large projects can face multi-year delays, sometimes exceeding ten years, particularly when the TSO network is congested. Customers may file complaints with the NRA if lead times are exceeded. While legislation stipulates that connections should be completed within two years, exemptions exist when reasonable justifications for delays are provided.
SI	Yes, rejections for solar generation are reported. Extent varies by region.	90 days.
SK	Connection request volume increasing strongly, but no queuing reported. Strict rules to filter project in early stages.	Within 30 days of receiving a connection request, the DSO shall send a draft Connection Agreement for the connection of the system user's equipment to the distribution system. The draft Agreement must be signed no later than 75 calendar days after issuance. The connection fee is to be paid within 15 days following the signing. The DSO will complete the construction of the electrical equipment necessary for the connection by the date specified in the Connection Agreement.

17.Process harmonization

- 17 countries harmonize at the DSO level and 10 at the national level, with some overlap possible as certain countries have only one DSO

	Level **- Country** **- DSO** **- Other**	**Form** **- Single Platform** **- Hybrid solution** **- Other**
AT	DSO	Single platform or hybrid depending on kind of connection. Some DSOs offer simplified processes for small units ≤ 20 kW.

BE	DSO	Hybrid
BG	Country	Similar processes but no standardization or common platform.
CY	Country	N/A
CZ	Country	Individual platforms for DSOs.
DE	DSO	Hybrid
DK	DSO	Hybrid
EE	DSO	Single One-Stop-Shop Platform.
ES	DSO	The process is facilitated through the DSOs’ electronic platforms, featuring standardized forms and a single point of contact. A fully digital procedure is employed, utilizing a single application form that integrates both the access permit and the connection permit.
FI	DSO	For DSOs with digital processes, application forms are available online and relevant information is provided on their websites. However, the level of detail and comprehensiveness of this information may vary depending on the specific DSO.
FR	DSO	Enedis, the primary DSO, offers an online platform for connection requests, although applications can also be submitted by phone. The procedure varies depending on the customer type: a simplified process is available for residential requests under 36 kVA, while businesses and renewable energy producers must follow different protocols, such as submitting requests through the S3REnR scheme.
GR	Country	N/A
HR	DSO	Hybrid. Forms are available on website.
HU	DSO	Hybrid
IE	DSO	Digital procedure in DSOs homepage.
IT	DSO	Digital procedure in DSOs homepage.
LT	DSO	A one-stop shop approach is provided, enabling the average citizen to manage the connection process independently.
LU	DSO	Technical connection conditions, which are jointly prepared by the DSOs and approved by the NRA, apply uniformly to all DSOs. Applicants must submit several key documents as part of the process, including a complete building permit, an extract from the cadastral plan, and a site plan.
LV	Country	A one-stop shop approach is provided, enabling the average citizen to manage the connection process independently. If additional network development is required, the DSO is responsible for selecting and dispatching contractors to carry out the necessary network upgrades.
MT	DSO	Online forms.

NL	Country	A common online platform is available for requesting grid connections. This platform is shared not only among all DSOs but also with other public utilities, such as water and sewage services.
PL	DSO	Available templates and online submission for each DSO.
PT	Country	A standardized digital platform operated by DGEG manages grid connection requests. For household self-consumption units, applicants register with technical details, after which DGEG notifies E-REDES and provides a link to track the process. Once operational, production, consumption, and feed-in data are accessible via the E-REDES Digital Counter website or app.
RO	Country	Most DSOs offer a digital, user-friendly platform with extensive information, while others provide less developed solutions.
SE	DSO	There is no common digitalization across DSOs. Some DSOs have developed their own platforms, as noted by interviewees, representing examples of progress in this area. However, overall, each DSO maintains individual solutions that are partially digitalized but not fully integrated.
SI	Country	Processes are unified and standardized across DSOs, with digital platforms employed for submission and approval. These digitalized and streamlined procedures meet the relevant EU requirements.
SK	Country	There is unification of processes among DSOs; however, individual DSOs manage specific aspects of distribution grid connections, resulting in minor variations. 2/3 of DSOs offer digital platforms, and informational videos are provided to facilitate the process.

18.Process digitalization

- All countries have at least partially digitalized processes, while 11 countries have achieved full digitalization.

	Level - Fully/No/Partially
AT	Partially. Depending on kind of connection (type, size, new or expansion). Some DSOs offer fully digitalized processes for small units ≤ 20 kW.
BE	Partially
BG	Partially; 1 of 3 DSO fully digitalized.
CY	Partially
CZ	Fully
DE	Partially
DK	Partially
EE	Fully

ES	Fully
FI	Partially
FR	Partially
GR	Partially
HR	Partially
HU	Partially
IE	Fully
IT	Partially
LT	Fully
LU	Partially
LV	Fully
MT	Fully
NL	Fully
PL	Fully
PT	Fully
RO	Fully digitalized for some DSOs.
SE	Partially
SI	Fully
SK	Partially

8.2. Appendix 2: Member state factsheets

Note: The appendix contains the 27 MS factsheets. For simplification purposes, the abbreviation NDP (network development plan) refers to plans at the distribution grid level.

Design features in Austria (AT)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: biennial – ***Public availability:*** *Yes* – ***Length:*** 20-115 pages, but no requirements specified – ***Language:*** German – ***NDP template provided?*** Yes – ***National NDP aggregating the DSO NDPs?*** No – ***Threshold for mandatory NDP development***: 50.000 metering points – ***Key elements of NDP***: Minimum information about current situation, planning principles and methods, current and planned grid development, infrastructure for connecting new generation capacities and loads, already used and planned utilization of flexibility, energy efficiency and energy storages and other resources as alternative option to grid development. NDP must include map and tabular presentation of the respective area of supply and its structural data as well as a detailed list of single projects and programs for grid reinforcement and extension. – ***NDP as Legal basis for investments*** No
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, ***Main deadlines***: 30th September – ***Geographical coverage***: Not explicitly mentioned, each DSO must present their area of supply – **NRA** must reviewed approve the NDP. Adjustments can be required at any time. – ***Consultation process***: Consultation of relevant stakeholder is required and executed. The results must be made public together with the NDP after approval, ***Alignment to TSO NDP?*** Yes, coherence with integrated grid infrastructure plan and current TSO NDP is required, ***Available data basis from TSO*** Yes. Data exchange not mandatory but can be used in the planning process.
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts: Policy goals (e.g. national or regional climate and energy strategies, legislative basis, historical and operational data and extrapolation, data exchange with TSO and their respective NDP, connection requests in short to mid-term planning – ***Consideration of flexibility by EVs*** No, ***HAC*** No, ***Other demand*** No, ***Storage*** No, ***Production curtailment*** No – ***Kind of proposed measures:*** Optimization of grid operation by different contract options (e.g. dynamic tariffs and limited grid use) as well as grid reinforcement and extension. Flexibility procurement no option due to lack of legislative basis.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Mainly energy-based and partly lump-sum ***withdrawal charges varying by*** voltage level and location – Mainly energy-based and partly lump-sum ***injection charges varying by*** voltage level and location – Optional ***variable network charges differentiated by*** season and ToD. ToU is mandatory if applicable in network area – ***Responsible party of tariff methodology***: NRA – ***Charges for storage:*** Paying reduced network charges only applies to PHES storages connected to the distribution grid. Injection is only energy based whereas withdrawal also considers power – ***Cost recovery based on*** average cost – ***Relative weighting of components***: energy > power
Regulation
Incentive based ***regulation*** considering a revenue cap for a 5 year period – ***Components of regulatory asset base*** intangible and fixed assets as well as book values – ***Anticipatory investments in asset base*** Yes, developments are considered and lead to a change of regulated cost base – ***Cost approval/scrutiny***: formal approval by NRA – ***Yardstick***

benchmark method: MOLS and DEA – ***Consideration of investment types*** OPEX adjusted based on price index, general productivity index and individual efficiency factor during regulation period as well as CAPEX adjusted annually based on efficiency-dependent return and encouraged during regulation period by mark-up on WACC – ***Time-dependencies due to base year and regulation period?*** Yes
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Individual capacity mapping – ***Transparency platforms for potential grid users:*** Capacity map exists. DSO must provide transparent information about available and reserved capacity at least 4 times a year. – ***Unification of requirements among DSOs for grid connection*** Yes for the general process, but individual conditions for each DSO ***and its standardization based on*** legislatively set requirements – ***Exemptions to file grid connection requests for*** small assets like EV charging stations < 3.7 kW.
Measures in case of lacking capacity
Assignment of grid capacity based on "First-come-first-serve" with the option for flexible grid connection in case of lacking capacity. – Shallow ***connection charges with*** components based on individual actual costs. Exemptions for RES and PHES storages as well as consumers in energy communities and based on location and voltage level – ***Conditional grid connection*** Yes, in the form of bilateral agreements between power generators and grid operators. Grid operator can impose limits to injection and there is no compensation in case of downward regulation requested by DSO.
Process for grid connection requests
Maximum lead time for processing: Depending on required capacity and voltage level the deadline can vary between 2 and 8 weeks – ***Default action in case of surpassing lead time***: In order to support renewables a grid connection request for home PV < 20 kW must be answered within 4 weeks otherwise it is considered as granted – ***Unification of process among DSOs*** Yes for the general process, but individual conditions for each DSO. ***based on*** legislatively set requirements – ***Fully digitalized process*** No. Some DSOs offer platforms to form requests online. For some an electrical expert must be involved. – ***Number of forms per request to submit***: Large heterogeneity depending on capacity, grid level and if construction is involved.
National grid conditions
Number of DSOs: 114 DSO thereof 15 with more than 50.000 metering points and therefore required to deliver NDP – ***Ownership structure:*** Mainly public – ***Length of grid:*** 270.645 km with 263.875 km in the distribution grid (2023) – **Network losses**: 2.956 GWh in 2023 – ***# of electric vehicles***: 196.448 BEV (11/2024) corresponding to 3.76% of overall vehicles in 2024 and policy target of 1.6 Mio. BEV in 2030 and 100% in 2040 – ***# of charging stations***: 25.590 stations (normal and fast) in 2024 and policy target of 400 (2025), 800 (2027) and 1.500 (2030) for fast charging stations – ***RES-E share:*** *87.8% in 2023 (of the RES share: 10.3% PV and 13.0% wind)* – ***Smart meter rollout:*** 82.45% of grid connection points in 2023 and policy target of 95% in 2024
National particularities
The requirements for network development plans at the distribution grid level are communicated in a highly structured manner by the NRA based on legal frameworks. Standardized templates are provided to ensure uniformity and efficiency in their preparation. Concepts of Citizen energy initiatives, including collective generation facilities, renewable energy communities, and energy sharing, are among the most developed across Europe.

Design features in Belgium (BE)

Note: In Belgium there are different regulatory regimes across the three regions (Wallonia, Flanders, Brussels). In case of differences between the regions, or if information is only available for some of the regions, this has been highlighted in the factsheet.

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Biennial reporting – ***Public availability:*** *Yes* – ***Length:*** 100 pages – ***Language:*** Dutch, French – ***NDP template provided?*** No – ***National NDP aggregating the DSO NDPs?*** No national aggregation of NDPs, but each (regional) regulator presents a summary of the NDPs it receives. – ***Threshold for mandatory NDP development***: No – ***Key elements of NDP***: Flanders: Publication of decision tree that is used by DSO in finding a balance between grid reinforcement or flexibility use + capacity maps showing load of transformers that connect the distribution grid with the transmission grid; Wallonia: Investment plan, development and distribution of budget and overview of structure and key figures of distribution grid
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, Flanders: Article 4.1.19 of the Energy Degree; Wallonia: Article 15 of the Decree of the 12 April 2001, updated in May 2022, ***Main deadlines***: Wallonia: Diverse; Flanders: DSOs must submit their NDP (including the public consultation) to the NRA before 1 October. Then NRA has 90 days to respond and accord. In case the NRA asks for additional information, they get an extension of 30 days. – ***Geographical coverage***: Flanders, Wallonia, and Brussels have their own regional regulator, DSO(s), and DNDP related processes – **Regional NRAs** approve the NDP – ***Consultation process***: Public consultation executed with all relevant network users and the TSO – ***Alignment to TSO NDP?*** Yes, alignment takes place ensuring consistency between the transmission and distribution network operators' scenarios, ***Available data basis from TSO*** Yes
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts Policy targets, prognose of connection requests, external consultant reports. – ***Consideration of flexibility by EVs*** Yes, ***HAC*** Yes, ***Other demand*** No, ***Storage*** Yes, ***Production curtailment*** No – ***Kind of proposed measures:*** Focus on grid reinforcement. Fluvius (Flemish DSO) does mention elements such as: dynamic operation, different tariff types, use of market-based flexibility, technical (obliged) flexibility, local automatic responses.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Energy-based and power-based (Flanders, actual maximum power in Brussels and Wallonia), lump sum (Brussels) ***withdrawal charges varying by*** voltage and (energy-based) time of use ***and exemptions for*** (in Brussels) network users <= 13 kVA pay an energy-based charge and a yearly lump sum fee based on the capacity of their connection; Network users > 13 kVA with peak measurement pay an energy-based charge and a power-based charge (€/kW) based on their actual monthly peak capacity (maximum of the last 12 months) during peak time of use – ***Injection charges*** power-based, lump sum in Wallonia, energy-based in Flanders, none in Brussels ***varying by*** voltage [voltage/location/time/none at all] – ***Variable network charges differentiated by*** periods: Wallonia: seasonal, within-day (2), Flanders: day of week (weekend/holidays), day/night (2), Brussels: day of week (weekend/holidays), day/night (2) – ***Responsible party of tariff methodology***: Regional regulator, regulatory periods of 4 years, yearly adjustment – ***Charges for storage*** injection: Flanders: E-based; Wallonia: P-based - withdrawal: Flanders: E- and P-based; Wallonia: E- and P-based; Flanders: gross withdrawal (net withdrawal + invertor power in case of no smart meter), Brussels: gross withdrawal, Wallonia: gross withdrawal (cap on the grid costs

based on net withdrawal + prosumer tariff) – ***Cost recovery based on*** average cost – ***Relative weighting of components***: energy > power
Regulation
Revenue cap ***regulation,*** which in Flanders focuses on reasonable and efficient cost recovery. Costs are split into endogenous (controllable) and exogenous (non-controllable) costs. Incentives for quality of supply and cost efficiency are provided. – ***Components of regulatory asset base*** in Flanders the RAB consists of tangible fixed assets such as land and buildings, machinery and equipment, installations, furniture and vehicles, fixed assets under lease, fixed assets under construction, other tangible fixed assets) – ***Anticipatory investments in asset base*** No – ***Cost approval/scrutiny***: Approval by regional regulator –***Consideration of investment types:*** In Flanders operating costs depreciation and return on assets are included as part of the endogenous costs, and for exogenous costs a baseline is determined that aggregates allowed operating and capital costs, subject to annual inflation – ***Time-dependencies due to base year and regulation period?*** Yes, for example the use of ‘regulatory balances’ in Flanders – ***Adjustable components during regulation period:*** In Flanders, annual adjustments for inflation and for efficiency incentives are done; Brussels region law allows adjustments for investments, divestments, depreciation and subsidies
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Comparable information tool – ***Transparency platforms for potential grid users:*** No capacity maps exist – ***Unification of requirements among DSOs for grid connection*** Within Wallonia and within Flanders requirements are uniform, but between them differences are present ***and its standardization based on*** regulations
Measures in case of lacking capacity
Deep connection charges with the following components: Individual actual cost (€); Lump sum (€) Contracted power (€/kVA) – ***Conditional grid connection*** Yes, flexible connections where, depending on the capacity limits of the network, a new connection can either be offered grid access on a firm or a flexible basis, or a combination of the two.
Process for grid connection requests
Maximum lead time for processing: A proposal needs to be sent out by the DSO within 10 days for low voltage cases in Wallonia, and withing 5 working days in Flanders. Generally, the connection then needs to be realised within 15 working days. – ***Default action in case of surpassing lead time***: In Flanders the DSO needs to pay a fee to the party that requests the connection for every day that the lead time is exceeded. The fee depends on the type of connection and ranges from 25 to 100 EUR per day. – ***Unification of process among DSOs*** No, requests need to be done at the DSO that is responsible for the distribution network in the location of the desired connection. No shared platform between DSOs to perform connection requests. – ***Fully digitalized process*** No, Flemish network codes state that requests can also be done via letter or phone. – ***Number of forms per request to submit***: In principle the DSO is the only institution that a person or entity that requests a connection has to communicate with. For an electricity connection in Wallonia, one needs to provide the installation acceptance report from an accredited body.
National grid conditions
Number of DSOs: 16 thereof 12 with more than 100k customers – ***Ownership structure:*** Publicly (mainly municipality) owned - ***Length of grid:*** 204k km (Low V. & MV combined) with 6.3 mio. connected customers –**Network losses**: 1.95% of net offtake (2024) – ***# of electric vehicles***: 4.2% BEVs of overall vehicles (2024) – ***# of charging stations***: 44,363 Charge Points (2024)– ***# of HAC per HH***: 6% (2023) of HH – ***RES-E share***: 31.4% in 2023 (of the RES share: 29.7% PV and 54.6% wind) – ***Smart meter rollout:*** *35*% of grid connection points (2023)
National particularities
Belgium has multiple regulators for regulation of distribution network operators (for the different districts: Flanders, Wallonia, and Brussels capital).

Design features in Bulgaria (BG)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: short-term and long-term plans but only to provide information for the TSO's NDP; short-term: every year for period of two years – ***Public availability:*** *No* –– ***Language:*** Bulgarian – ***NDP template provided?*** List of required contents by NRA – ***National NDP aggregating the DSO NDPs?*** No – ***Threshold for mandatory NDP development***: No threshold – ***Key elements of NDP***: measures to improve the efficiency and modernize the existing network; construction of new network facilities; DNDP shall be accompanied by technical, economic and environmental analysis, financial plan and measures to reduce technological costs
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? No, only plans for TYNDP as input and investment plans – ***Main deadlines***: for plans related to price/tariff applications March 31st – ***Geographical coverage***: designated service area – **NRA's role:** NRA approves the investment programs – ***Consultation process***: No – ***Alignment to TSO NDP?*** Yes, according to the Rules for management of electricity distribution networks, DSOs shall provide information for the development plan of the TSO – ***Available data basis from TSO:*** No
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts: Forecasts are based on short-term, medium-term and long-term energy consumption forecasts; the provisions of the development plans of settlements, the plans for regional development and other forecast developments; analyses of determining factors (population size, opportunity for use of other energy carriers, economic development indicators); new connection request of consumers and producers – ***Consideration of flexibility by EVs, HAC, other demand***, ***storage***, ***production curtailment:*** No – ***Kind of proposed measures:*** Grid reinforcements (based on the regulation), transferring overhead power lines underground
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: energy-based, power-based – ***Withdrawal charges vary by*** voltage and customers, household network users have energy-based, non-household network users have mix of energy and power-based tariffs – ***Injection charges vary by*** none – ***Variable network charges differentiated by*** none – ***Responsible party of tariff methodology***: NRA, yearly prices, three year periods – ***Charges for storage:*** no charges – ***Cost cascading:*** from transmission to distribution; explicit payment (separate tariff or tariff element) – ***Cost recovery based on:*** average cost – ***Relative weighting of components***: E>P
Regulation
Type of regulation: Cost-based with capped income 3 years period; yardstick benchmark; technological losses, Z factor and +/- 5%; The average market price used to calculate needed returns to source technological losses from the market – **Components of regulatory asset base:** book value, amortization, any assets acquired through financing from EU or other public funds is excluded from the RAB – ***Conditionality***: No –***Assessment of network quality:*** SAIFI/SAIDI but they are not correlated to investments or costs approval – ***Depreciation method:*** straight line and degressive – ***Depreciation time/ ratio:*** depends on asset type – ***Depreciation consideration:*** pass-through – **Time-dependencies due to base year and regulation period**: Yes; (end of period (3rd year) there is an adjustment if needed) – ***Additional cost adjustments:*** Yes, based on fulfilment of investment program – ***Consideration of anticipatory investments:*** No specific provisions or approvals, investments have to be justifiable with current needs and projects

Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Third party reporting – ***Transparency platforms for potential grid users:*** On one interface, you can search by area to see if there is free capacity (for RES producers) but no information on the exact available capacity – ***Unification of requirements among DSOs for grid connection:*** Standardized based on Regulation 6/2014 (NRA) – ***Exemptions to file grid connection requests:*** No exemption for grid connection requests
Measures in case of lacking capacity
Assignment of grid capacity: DSOs shall indicate the reasons for the refusal and the necessary measures to eliminate them, including ensuring conditions for connecting the facility, in accordance with the network development plans and a timeframe to address them – ***Connection charges:*** Shallow connection charge based on distance, pre-approved tariff within urbanized areas and real costs outside of urbanized areas: first user pays all costs; charge based on contracted power; exemptions: No exemption, discounts or differences, variation based on voltage (No) and location (No) – ***Conditional grid connection:*** No
Process for grid connection requests
Maximum lead time for processing: DSOs shall determine the conditions, prepare and provide a written opinion on connection to the person who submitted a connection request, within 14 days; 30 days with additional document requests – ***Unification of process among DSOs:*** Similar processes but no standardization; no common platform – ***Fully digitalized process*** Only in one of the three DSOs
National grid conditions
Number of DSOs: 4 legally unbundled DSOs – **Threshold for unbundling:** 200 000 customers – ***Ownership structure:*** Two are owned privately by Bulgarian private companies and one is owned by a foreign investor – ***Connected customers:*** 4.5 mio. connected customers – ***Policy targets for electric vehicles and charging stations:*** No specific target in the strategy documents – Current situation (2023): 1586 charging stations in 1126 locations; 14517 EVs – ***Policy targets for HAC per HH:*** No specific target in the strategy documents - number of heat pumps in 2020: 220 000 – ***RES-E share targets:*** 29.4% in 2023 (of the RES share: 32.4% PV and 13.5% wind) – ***Smart meter rollout:*** Smart meters are currently not an approved type of investment by the NRA
National particularities
In Bulgaria there are differences in calculating grid access fees, but the NRA tries to standardize. Investments that are only partially financed are not eligible as part of the RAB. This is a disincentive to participate or invest in innovative, climate-oriented activities. It is necessary to consider the investment cost in addition to the subsidy. Lack of incentives to invest in future-proof network. Significant RES (PV) is connected to DSO level, which leads to operational issues. Generation must be transmitted to other areas to consume. More investment is needed to digitalization, greater attention should be paid to flexibility services.

Design features in Croatia (HR)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Yearly update - HEP ODS, the sole DSO of Croatia, creates a ten-year network development plan of the distribution network with detailed investments in the next three-year and one-year period – ***Public availability:*** Yes, on HEP's website – ***Length:*** 247 pages – ***Language:*** Croatian – ***NDP template provided?*** No template, key requirements are set in the Electricity Market Act and the distribution grid code – ***National NDP aggregating the DSO NDPs?*** There is only one DSO – ***Threshold for mandatory NDP development***: 100.000 customers set by law, but not relevant as there is only one country-

wide DSO – ***Key elements of NDP***: Detailed investment plan for the next one year, three years and ten years.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes – ***Geographical coverage***: National – ***Timeframe***: Jan 2024 to Dec 2033 – ***NRA role*** NRA (HERA) holds its own public consultation, and approves the plan before publishing – ***Consultation process***: 2-step consultation: DSO consults the draft plan with the interested public for min. 15 days, NRA also consults the proposal the final NDP for another min. 15 days. Consultation results are available on HEP's and HERA's websites. The final DNDP for 2024-2033 has been modified according to comments of the consultation process – ***Alignment to TSO NDP?*** According to the Energy Market Law the development plan shall be in accordance with the TSOs TYNDP. The TSO and DSO hold coordinating meetings and align their activities, especially concerning demand forecast scenarios, planning and economical evaluation (CBA) of jointly owned infrastructure, connection of distributed generation having impact on transmission system. – ***Smart meter data access:*** The rollout of smart meters and implementation of AMI is currently one of the most intensive activities in HEP DSO and in focus of current and several future DNDPs. However, smart meters are already an important and indispensable source of data, especially for distributed generation, whose 15-minute active power load diagrams are required for any distribution network analysis or planning. Another very important improvement in planning process accuracy is enabled by use of data from the control meters in the MV/LV substations in the distribution network.
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Scenario building and forecasting: Forecasts of electricity consumption and peak load of the distribution network of HEP ODS were made for five-year periods until 2040 in the study "Forecasting trends in electricity consumption and load on the Croatian distribution network". Connection requests are also included in long-term demand scenarios for DNDPs. – ***Basis for load and production forecasts:*** According to the Energy Market Act forecasts shall be based on the Energy Development Strategy of the Republic of Croatia until 2030 with a view to 2050, the NECP, the Strategy for Physical Planning of the Republic of Croatia and spatial plans, the TSO’s TYNDP. – ***Flexibility forecasting:*** Not yet integrated, but planned, the assessment of needs is ongoing. The DSO has prepared several studies to prepare for the technical and legislative framework for flexibility and is interested in pilot projects for approaches that are alternative to network reinforcements. Currently the system for the use of SCADA and smart metering 15-minutes data is being developed. – ***Kind of proposed measures:*** No measures but “business goals”, mainly focusing on increasing network capacity. Expected increase in investments for connections below 20 kV mentioned.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Charges for withdrawal overall: energy-based, power-based (actual power at peak period); variation by voltage level, no variation by location. ToU E- and P-based. – ***Reactive energy charges*** for both transmission and distribution charges – ***Injection charges*** for both transmission and distribution applied as of 2023. Injection tariffs are variable power based, charged per monthly peak power injected to the grid, equal for all technologies, applicable only to licensed producers (connection power over 500 kW), i.e. prosumers are exempted. However, as prices are regulated (in power until March 31. 2025), currently injection charges both at DSO and TSO level are set at 0 EUR/MW. ***Variable network charges differentiated*** within days (day 06:00-22:00, night 22:00-06:00). specifics: mandatory for connection rate >20 kW, optional for the rest; "public lighting" excluded from ToU; ToU tariffs applied for 50%-75%; <10% of D-connected users have connection rates >20 kW – ***Responsible party of tariff methodology***: HERA (NRA) – ***Update frequency*** 1 year – ***Treatment of storage facilities*** injection charge as of 2023 (see note above). withdrawal: E- and P-based; gross withdrawal. no differentiation / exemption. – **Treatment of prosumers:** No injection charge, E- and P-based, net

withdrawal for households which have their own electricity production. – **Cost recovery based on** forward-looking cost model. The main objective of the approach is to take into account costs change in the next regulatory period (year) and ensure their coverage through network tariffs in next regulatory year. For DSO's network charges the unit price is distinguished for medium voltage connections and for low voltage connections and differ across groups of network users. – ***Residual costs***: the regulator may decide to correct the recognised expenses plus incentives, if the absolute value of the corrected difference between the realized revenue and the recognized costs with incentives in the previous registration year is greater than 3% of the recognized costs increased by incentives in the previous registration year. **Relative weighting of components**: E>P – ***Cost cascading*** from transmission to distribution, from distribution to distribution; explicit payment (separate tariff or tariff element)
Regulation
Type of regulation: cost-based with cost-plus regulation including cost of service, rate of return, 1 year, postage stamp principle used to determine amount of tariff items (equally for all voltage levels and consumers). – ***Components of regulatory asset base*** Asset base includes average value of regulated assets in the beginning of the year and at the end and excludes value of assets received without charge, financed by grants. – ***Anticipatory investments in asset base*** No. Historic cost approach. – ***Depreciation method*** straight line – ***Depreciation time:*** statutory, based on asset type – ***Depreciation consideration:*** amount of allowed annual depreciation is included in CAPEX. – ***Consideration of investment types*** as OPEX are included costs of network maintenance, costs of loss coverage in the network, costs of gross salaries, other staff costs, other business-related costs; revenue should cover OPEX and CAPEX – ***Time-dependencies due to base year and regulation period?*** CAPEX is average value at the beginning and at the end of the year (hence including new investments) – ***Adjustable components during regulation period:*** difference between realised income and acknowledged total costs is taken into account for the next regulation year.
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: The hosting capacity includes all production plants that are connected to the distribution power grid and those that are in the process of being connected. – ***Transparency platforms for potential grid users:*** The Electricity Market Act stipulates that data on the use of the transmission and distribution systems shall be public, updated once a year and published on the webpages (The hosting is planned to be updated quarterly.) ***Unification of requirements among DSOs for grid connection*** not applicable, since only one DSO – ***Technical requirements*** on July 14, 2023, HEP ODS adopted new Rules on connection to the distribution network (in force as of Sept 1, 2023): new procedure for the connection of energy storage producers and operators + preliminary connection procedure, possibility of applying an operational restriction on the use of connected power will be defined in the connection contract. New simplified connection procedure under 11.04 kW. – ***Exemptions to file grid connection requests for EVs, HPs & RES, etc.*** No exemption
Measures in case of lacking capacity
Assignment of grid capacity: no exact information, HEP (and legislation) only states that it connects customers "in a transparent and non-discriminatory manner". According to legislation neither the TSO, nor the DSO may deny access to the new generator based on possible future network limitations or additional costs related to an increase in network capacity. Prosumers: HEP verifies connection possibilities (no information on the criteria and the decision-making process). – ***Connection cost charging fees:*** Deep connection charge based on individual actual cost contracted power; differentiation: producers vs. consumers, no variation based on voltage or location – ***Conditional grid connection***: Yes. New rules (in force since October 2022) allow that the use of network agreement may comprise

provisions regulating operational limitations as an interim solution, with a clearly defined duration and the mutual rights and obligations of the system operator and network user.
Process for grid connection requests
Maximum lead time for processing: 15 days in the simple procedure, in the complex procedure 30 days to 12 months, depending on the type and installed capacity of the connected asset – ***Fully digitalized process*** Yes, forms can be downloaded from HEP's website.
National grid conditions
Number of DSOs: 1 DSO, 2.5 million connected customers, legally unbundled – ***Ownership structure:*** state-owned – ***Length of grid:*** 141 937 km – **Curtailment** RES curtailment 45 GWh (2023) – ***Network losses***: 7.13% losses (2023) – ***E-mobility development:*** ACER reports # of electric vehicles: 7000, EV charging stations: 1000, NECP forecast 2030: 244 413 EVs, total number of charging points to be built in residential areas: 1181. – ***# of HAC per HH***: Number of heat pumps 2023: 4330 (estimate), Policy target for heat pumps 2030: 240.000. - ***RES-E share***: 58.8% in 2023 (of the RES share: 3.8% PV and 23.7% wind) – ***Smart meter rollout:*** 2025 data: 195,665 (82%) advanced meters for network users in the business category; around 1 million (43%) advanced meters for network users in the household category.
National particularities
The Advanced Network Concept of Croatia (described in Article 3, point 62 of Electricity Market Act) acknowledges the need for the modernization of the network, close cooperation between DSOs and network users, the need for automatization and data management, etc. The DNDP mirrors these approaches, and the DSO engages in several pilot projects.

Design features in Cyprus (CY)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Biennial reporting – ***Public availability:*** Yes – ***Length:*** 109 pages – ***Language:*** Greek – ***NDP template provided?*** No – ***National NDP aggregating the DSO NDPs?*** N/A as there is only one DSO – ***Threshold for mandatory NDP development***: No
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes – ***Geographical coverage***: National coverage – **NRA** approves the NDP – ***Consultation process***: Public consultation executed with stakeholders incl. consumers, businesses and environmental groups. Government and local authority bodies are consulted to ensure the plan aligns with national policy strategies and local development needs. – ***Alignment to TSO NDP?*** Yes, the NRA is responsible for the alignment of the TSO and DSO NDPs, ***Available data basis from TSO*** Yes
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts NECP, load forecasting, system and reliability studies, EU targets – ***Consideration of flexibility by EVs*** No, ***HAC*** No, ***Other demand*** No, ***Storage*** No, ***Production curtailment*** No – ***Kind of proposed measures:*** Mainly grid reinforcements. Smart grid and digitalisation is another important part of the NDP.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Energy-based ***withdrawal charges varying by*** voltage – No ***injection charges*** – No ***variable network charges*** but framework allows for season and peak/off-peak – ***Responsible party of tariff methodology***: NRA – ***Charges for storage*** – No storage facilities are connected yet (if so: no withdrawal charge beyond connection charge) – ***Cost recovery based on*** average cost – ***Relative weighting of components***: energy > power
Regulation

Incentive-based revenue cap ***regulation*** – ***Components of regulatory asset base*** depreciated fixed assets, working capital – ***Anticipatory investments in asset base*** No - ***Cost approval/scrutiny***: NRA approval - ***Consideration of investment types*** split into controllable and non controllable OPEX -
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Unification of requirements among DSOs for grid connection N/A as there is one DSO – No ***exemptions to file grid connection requests***
Measures in case of lacking capacity
Assignment of grid capacity based on first-come-first-serve model for most general applications. The aim for the DSO is to balance the capacity for existing users, new connections, and renewable energy integration. Primary priority for assigning grid capacity is ensuring the reliability of the network. Priority is then given to existing users (i.e., to maintain stable electricity supply). Connections that are critical to public services e.g., hospitals are also prioritised. – Shallow ***connection charges with*** multiple components, charges based on €/kVA (different charges for residential and industrial consumers, variation based on voltage and location) – ***Conditional grid connection*** Yes, available but typically applied under specific circumstances where immediate connection to the grid is not possible due to capacity limitations, or other technical constraints
Process for grid connection requests
Maximum lead time for processing: 6 – 12 months (depending on type of connection) – ***Unification of process among DSOs*** N/A (only one DSO) – ***Number of forms per request to submit***: The admin burden can be significant. Several institutions are involved in the process incl. the NRA, the TSO, municipalities and environmental agencies. Requests often require coordination between the NRA, the TSO and local municipalities for land use permits and zoning approval.
National grid conditions
Number of DSOs: 1 (EAC) – ***Ownership structure:*** State ownership - Majority of EAC's shares (>99%) are owned by the Cypriot government – ***Length of grid:*** 26,000 km with 0.6 mio. connected customers - **Network losses**: 4.6% (2018) – ***# of electric vehicles***: 4% BEVs of overall vehicles (2024), Cyprus targets for 20% of all vehicles to be electric by 2030 – ***# of charging stations***: 372 Charging Points (2024) – ***# of HAC per HH***: Heat pumps account for 23% of the final energy consumption in the residential sector (2024), Cyprus aims to double the use of heat pumps in buildings by 2030 – RES-E ***share***: 20.9% in 2023 (of the RES share: 74.4% PV and 20.7% wind) – ***Smart meter rollout:*** 0% of grid connection points (2023)
National particularities
Cyprus currently depends entirely on domestic generation. Interconnectors are in development (e.g. with Israel). This explains why Cyprus is heavily reliant on oil and gas for electricity generation. EAC also operates as a monopoly in electricity generation, transmission and distribution.

Design features in Czechia (CZ)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: DSOs publish a development plan every year that plans for 5-year periods, but only contains the list of expected new investments (these documents do not completely replace DNDPs). – ***Public availability:*** *Yes* – ***Length:*** 3-5 pages – ***Language:*** Czech – ***NDP template provided?*** No – ***National NDP aggregating the DSO NDPs?*** The investment development plans all apply to the DSOs' own areas. There is no summary document – ***Threshold for mandatory NDP development***: No – ***Key elements of NDP***: List of expected investments.

Procedural steps, data collection and governance of NDPs
Obliged by national legislation? No, Energy Act (No. 458/2000 Coll.) oblige DSOs to annually process and publish the expected development of the distribution system, for at least 5 years – ***Geographical coverage***: Each DSO responsible for its designated service area – **NRA's role:** The NRA (ERO - Energetický regulační úřad) monitors and approves investment and network development activities and the investment plan of DSOs. – ***Consultation process***: No –***Alignment to TSO NDP?*** Yes – ***Available data basis from TSO:*** No
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts: There are no scenarios linked to the list of investment development plans in the publicly available documents. – ***Consideration of flexibility by EVs, HAC, other demand***, ***storage***, ***production curtailment:*** No – ***Kind of proposed measures:*** Only grid reinforcements
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: Energy-based, power-based (contracted or rated power) – ***Withdrawal charges vary by*** voltage and time. Some network users (MV or HV) have the option to have energy-based tariff only. However, this option is taken by a fraction of the eligible network users. The rest of the users have a mix of energy- and power-based charges. – ***Injection charges vary by*** none – ***Variable network charges differentiated by*** seasonal periods (monthly or yearly capacity charge), day of week in LV, peak/off-peak. Set by individual DSOs. Optional: users who do not meet conditions are excluded, ToU tariffs applied for 50%-75% of the number of D-connected users – ***Responsible party of tariff methodology***: NRA, methodology is set for 5 years, then adjusted yearly – ***Additional regulation for network operation:*** remote control (certain devices can be blocked in peak hours by the DSO, this is linked to ToU tariffs) – ***Charges for storage:*** injection: no charge (only PHES storage connected); withdrawal: E-based, some exemptions apply; gross withdrawal. (If non-PHES storages were connected, no exemption from power-based component) – ***Cost recovery based on:*** average cost – ***Relative weighting of components***: P>E – ***Cost cascading:*** from transmission to distribution, from distribution to distribution; implicit payment (no separate tariff or tariff element)
Regulation
Type of regulation: Incentive regulation (revenue cap) with 5 years period (currently 2021-2025); yardstick benchmark; other elements: eligible costs, eligible depreciation and amortisation, RAB, WACC – **Components of regulatory asset base:** fixed assets, investments in progress, leased assets, no working capital – ***Regulatory asset value:*** The RAB is based on re-evaluated values of assets commissioned by 2005 (or 2006 – depends on the energy sector) and on historical values of assets commissioned in 2006 (or 2007 – depends on the energy sector) and later. These values of assets are recorded in the annual financial statements. – ***Conditionality***: Yes – ***Yardstick benchmark method: No explicit model,*** regulator sets efficiency targets at the beginning of the RP – ***Time to eliminate inefficiencies in years:*** RP (5 years) – ***Assessment of network quality:*** SAIDI, SAIFI – ***Depreciation method:*** straight line – ***Depreciation time/ ratio:*** depends on asset type – ***Depreciation consideration:*** pass through –***Time-dependencies due to base year and regulation period:*** For each regulated year the eligible cost base is determined on the basis of the actual costs of the last three completed reference years, e.g. regulated year 2023 is based on 2019-21 costs – ***Other components to adjust costs during regulation period:*** Eligible depreciation and amortisation are determined based on the planned values in individual years of the RP. The planned values of the depreciation are adjusted in the year i+2 based on the actual values using the time value of money.
Timely and transparent treatment of grid connection request
Determination of grid connection potential

Methodology for grid hosting capacities: Capacity mapping by DSOs – ***Transparency platforms for potential grid users:*** *Interactive capacity map,* List of available capacity on 110 kV lines and on 110 kV/HV distribution transformers– ***Unification of requirements among DSOs for grid connection:*** The overarching framework is the same, some DSO-specific variations exist, particularly in procedural and local technical details (Energy Act (No. 458/2000 Coll.)
Measures in case of lacking capacity
Assignment of grid capacity based on: FCFS – ***Connection charges:*** Shallow connection charge based on individual actual cost; contracted power; variation based on voltage and location (Difference between network users connecting to rural and urban areas) – ***Conditional grid connection:*** Yes
Process for grid connection requests
Maximum lead time for processing: deadlines for every step: the shortest deadline from the request for network connection to the sending of the draft contract is 30 days. The process can be significantly longer if the DSO also requests a connection plan. – ***Unification of process among DSOs*** Standardization by Decree No. 51/2006 Coll. (minor differences in practice) – ***Fully digitalized process:*** Yes – ***Number of forms per request to submit***: DSOs have online platforms for connection requests. In the case of households, the process is simplified and only needs general information (personal and contact data and technical details).
National grid conditions
Number of DSOs: 3 legally unbundled with more than 100 k customers, which supply the vast majority of the consumers – ***Ownership structure:*** Private and local public ownership – ***Connected customers:*** 6.2 mio. connected customers – ***Policy targets for electric vehicles and charging stations:*** Current situation (2024 June): BEV: 27600; Charging stations: 5201. Policy targets for 2030: BEVs: 200 000 - 450 000; Charging stations: 10485-28250 – ***Policy targets for HAC per HH:*** number of HPs in 2023: 350 000 – ***RES-E share:*** 16.4% in 2023 (of the RES share: 26.3% PV and 6.2% wind) – ***Smart meter rollout:*** 3% smart meter deployment
National particularities
The development of the legal environment of DNDPs are in progress, the requirement of DNDPs would help to give a strategic direction for investments. The current status of smart-meter penetration is lagging behind other EU Member States. Potential fast deployment of smart meters is expected to enhance the optimal grid planning and operation.

Design features in Denmark (DK)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Every 2 years – ***Public availability:*** *Yes* – ***Length:*** *approx. 80 pages.*– ***Language:*** *primarily published in Danish, with summaries or key sections available in English* – ***NDP template provided?*** Yes – ***National NDP aggregating the DSO NDPs?*** *DSO produces its own plan*, the NDPs aren't merged into one national document. The Agency may internally aggregate certain figures (like total battery capacity), but it is not publicly published as a single report. – ***Threshold for mandatory NDP development***: No – ***Key elements of NDP***: 10-year outlook of future demand/production, including relevant capacity maps. Plans highlight grid congestion points, proposed reinforcements, and possible flexibility solutions (e.g. demand response). Also highlighting grid congestion points based on predicted increases in solar and wind production. – ***NDP as Legal basis for investments*** No
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? DSOs must produce NDPs per national requirements. – ***Main deadlines***: Updated biennially. – ***Geographical coverage***: The NDPs cover the entire

national territory, with each DSO responsible for its designated service area – **NRA' role:** The Danish Utility Regulator (DUR) reviews the NDP for compliance; there is no formal "approval" step that legally binds the DSO, but DUR may provide feedback. – ***Consultation process***: DSOs draft the NDPs, which are then reviewed and approved by the DUR. Public consultations are conducted to gather input from stakeholders, and other interested parties. – ***Alignment to TSO NDP:*** *Yes, TSO comments are generally built into the DSO's plan.* ***Available data basis from TSO:*** *No, DSOs have comprehensive rights to use consumer metering data for planning.*
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts: DSOs combine actual connection requests, policy targets, and local stakeholder dialogues (e.g., municipalities, industrial users). – ***Consideration of flexibility by EVs, HAC*, Battery storage** DSOs must explicitly consider **flexibility** in their forecasts, although the level of detail varies across the DSOs. EVs, heat pumps, and storage are included in many DSOs' scenario work – ***Kind of proposed measures:*** Grid reinforcements, new lines or transformers, local flexibility services (e.g., curtailment, demand response).
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: typically combines energy- and capacity-based components. Connection charges are generally "deep," recovering both direct and reinforcement costs, with exceptions e.g. for flexible connection agreements; ***withdrawal charges varying by*** Voltage level (low V vs. HV), Time of use (peak vs. off-peak, seasonal), Power demand (for HV, a portion of CAPEX may be billed via capacity-based charges), User category – some HV or MV users can opt for an energy-only tariff, though the majority adopt a mix of capacity and energy charges. ***Exemptions for*** withdrawal charges are generally, not specific universal exemption; however, flexible connection agreements may yield lower or "shallower" connection charges for users accepting curtailment or partial load constraints. ***injection* charges** Voltage level (above or below 10 kV). Geographical zones (producer-dominated, consumption-dominated, mixed) that affect deep connection fees. Time-of-use factors typically do not apply to injection unless the DSO imposes extra charges for network losses or capacity usage ***varying by*** none at all ***and exemptions for*** : storages are treated like any user consuming and injecting power; no dedicated tariff yet. **Prosumers**: No special discount. They pay for the capacity dimension they impose, including injections. **Flexible connection agreements** (since 2019 for consumers, 2023 for producers): Offer shallower charges if the user accepts curtailment or other constraints. – ***Variable network charges differentiated by*** Time: peak/high-load vs. low-load zones, plus possible weekday/weekend or seasonal variations., Location: zone-based charges for producers or large consumers., Voltage level: Low V vs. MV/HV. – ***Responsible party of tariff methodology***: DSOs design their methodology often coordinated via Green Power Denmark and must submit significant changes to the regulator for approval. – ***Cost recovery based on*** A combination of deep connection charges plus usage tariffs (covering CAPEX/OPEX). DSOs pass recognized costs into a regulated revenue cap, shaping final tariff levels.– ***Relative weighting of components***: High-voltage often ~25% CAPEX via power-based charges, ~75% via time-differentiated energy. Low-voltage primarily time-differentiated energy-based for CAPEX, plus a small lump-sum for metering/admin.
Regulation
Regulation: Overall, Incentive based, using prior-period costs plus efficiency requirements (and a reliability/quality component). Only the application-based supplements have a more "cost-based" element – ***Components of regulatory asset base*** Typically licensed DSO assets, including infrastructure used for distribution. Intangible items (e.g., IT systems) may be included if they serve DSO functions. – ***Anticipatory investments in asset base*** DSOs may propose forward-looking or "anticipatory" investments (e.g., larger cables anticipating future EV load). DSOs bear the risk of "anticipatory" expansion and they must justify

expansions with real near-term demand or face potential shortfalls in revenue. There is no fixed definition of “anticipatory,” – ***Cost approval/scrutiny***: Major investments are scrutinized for efficiency before inclusion in the RAB. – ***Yardstick benchmark method***: straight line, depending on the type of asset – ***Consideration of investment types*** Both CAPEX (grid expansion, cables, substations) and OPEX (maintenance, overhead) are recognized, subject to regulator’s efficiency checks.– ***Time-dependencies due to base year and regulation period?*** Yes
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: The Capacity Map is based on the grid's total current capacity for generation. Then, the capacity used by all existing generation plants is subtracted. Finally, the capacity agreed for use by future, but not yet connected, production plants is deducted. – ***Transparency platforms for potential grid users:*** capacity maps – ***Unification of requirements among DSOs for grid connection*** Yes ***and its standardization based on*** standardized forms – ***Exemptions to file grid connection requests for*** demand installations to the low-voltage grid (≤ 1 kV), from the requirements in these instructions under special circumstances.
Measures in case of lacking capacity
Assignment of grid capacity based on: “first come, first served,” with DSOs more likely to connect projects that pay or demonstrate “maturity” faster. – ***Connection charges with*** Deep connection charge with geographic differentiation for producers >10 kV.– ***Conditional grid connection:*** Yes, grid users can opt for a non-firm portion of capacity at a heavily reduced connection fee.
Process for grid connection requests
Maximum lead time for processing: there is no strict, standard deadline for providing a grid connection. Instead, the timeline varies significantly depending on the project size and the extent of reinforcement needed. “Simple” connections (e.g., a small rooftop solar) can take weeks if no major expansions are needed. for small rooftop solar (under ~10 kW), DSOs must respond within 30 days whether it’s approved or needs more assessment. Complex connections (Large projects) (requiring new transformers or TSO-level projects) can stretch to months or years—permits, environmental approvals, and municipal negotiations. – ***Default action in case of surpassing lead time***: There is no explicit legal penalty or automatic refusal if the DSO fails to connect within the two-year target. Instead, an affected user may file a complaint with the Danish Utility Regulator (DUR) if they believe the DSO has unreasonably delayed the process. The regulator can then investigate and, in some cases, mandate expedited solutions or impose requirements on the DSO. Users can file a complaint with the regulator if they believe they’re unreasonably delayed– ***Unification of process among DSOs*** *Yes* ***based on*** hybrid - ***Fully digitalized process*** hybrid – ***Number of forms per request to submit***: Small-scale users (households, small commercial) typically fill out straightforward application forms. Large-scale projects must submit more detailed technical, financial, and environmental data.
National grid conditions
Number of DSOs: 38/40 (with more than 100 k customers: 10)/ 44 – ***Ownership structure:*** Private and local public ownership – ***Length of grid:*** 165,000 km– ***Curtailed demand and supply and demand***: from 1978 through 2020, Denmark has seen a total loss of 7.85 TWh of wind energy production through a combination of curtailments, faults and failures as well as age-related asset performance degradation. Since 1990 Danish security of electricity supply has been at approximately 99.99%. This corresponds to an average consumer being without power for 40 minutes over the course of a single year. – **# of electric vehicles and charging stations**: 23072 Charge Points, 819 Capacity (kW), 0.08 Share CPs > 150 kW, 169521 # BEVs, 36 Average Speed (kW), aims to reach 775,000 electric cars in 2030. – ***# of HAC per HH***: green heat to more than 1.8 million HH; more than 58,000 homes received district heating in 2022: today, 76.9 per cent of district heating comes from RES, targets to reach 100% by 2030; 40% of commercial buildings that are currently heated with fossil fuels;

Prognosed 2035 target: Individual Heat Pumps: ~15 TWh, Large-Scale Heat Pumps: ~5 TWh – **RES-E *share***: 79.4% in 2023 (of the RES share: 11.5% PV and 65.4% wind) – ***Smart meter rollout:*** Smart grid network initiative: Danish cities are investing in smart grid technology as part of broader smart city initiatives; investing in digital, vendor-agnostic, and cybersecure grid automation solutions
National particularities
Denmark features a relatively high number of DSOs serving a small geographic area, resulting in diverse ownership structures but a unified regulatory framework. Its grid connection processes are notable for allowing flexible (non-firm) agreements to mitigate capacity constraints, and a maturity model ensures only credible projects reserve capacity. The country's Tariff Model 3.0 distinguishes low V vs. HV users in both energy and capacity pricing, and deep connection charges are often geographically differentiated, reflecting whether an area is producer- or consumption-dominated. Denmark features universal smart meter coverage, enabling advanced time-differentiated tariffs and wide-scale integration of EVs and heat pumps. DSOs commonly employ flexible (non-firm) connections and a maturity model to manage capacity constraints, ensuring that only credible projects block grid capacity. Storage is currently treated as standard load plus injection, lacking specialized tariff categories or exemptions. Similarly, prosumers pay standard capacity/energy charges under Tariff Model 3.0, with no unique discounts or rebates. Despite this, high uptake of EVs and heat pumps demonstrates Denmark's strong focus on flexibility; DSOs rely on time-of-use billing, technical requirements, and flexible agreements to maintain grid stability in areas of rapid electrification.

Design features in Estonia (EE)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Biennial reporting – ***Public availability:*** Yes – ***Length:*** 48 pages – ***Language:*** Estonian – ***NDP template provided?*** Yes, Competition Authority has NDP templates in place – ***National NDP aggregating the DSO NDPs?*** One major DSO, the other Imatra Elekter AS is its subsidiary, has ~25,600 customers, and its network development needs are covered in the DNDP of Elektrilevi AS. Other local DSOs may also develop own DNDPs like Elektrivorgu Arengukava. – ***Threshold for mandatory NDP development***: Not yet, but future regulation may introduce threshold – ***Key elements of NDP***: Capacity maps exist, DNDP gives a detailed account on investment principles and needs; Maps in the DNDP show the change in network load and production, making a case for investment. The network development principles are based on the requirements of the standard EVS-ISO 55001 and the requirements described in the relevant legislation. The network development process is iterative and is based on organisational principles.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes (Electricity Market Act paragraph 66 (1-7)) – ***Main deadlines***: DSO submit the estimated demand until 15 April to the Competition Authority. Competition Authority forwards to TSO – ***Geographical coverage***: 95% of the country, service area, some islands have dedicated DSO – ***NRA's role:*** Competition Authority approves and reviews the network development needs of the DSO, TSO and market operator each year. – ***Consultation process***: Public. Consultation has been done. Chapter 6.2 of the DNDP includes direct feedback of the public consultation and answers of Elektrilevi. – ***Alignment to TSO NDP?*** Yes – ***Available data basis from TSO:*** DNDP explicitly refers to Elering (TSO) "Study to determine Estonian electricity demand scenarios, Study no S3, 20/09/2022" and "Energia teekaardi värskendus- teekaart 2023",Rohetiiger.
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings

Basis for load and production forecasts: Two studies on Estonian future energy demand considered most recent and reliable by the DSO at the time of writing the DNDP: "Energia teekaardi värskendus- teekaart 2023", Rohetiiger; "Study to determine Estonian electricity demand scenarios, Study no S3, 20/09/2022"– ***Consideration of flexibility by EVs, HAC, other demand***, ***storage***, ***production curtailment:*** Flexibility is mentioned as a concept in chapter 4.7.1, noting that the market shall provide this service in the most cost-efficient manner. Elektrevi was part of H2020 projects related to flexibility solutions. For example, "Elektrilevi has carried out a procurement of flexible services in the Hiiumaa region in order to find alternatives for investments and timelines. The aim of the flexible services is to enable additional customers to be connected to the network when the capacity of the existing network is exhausted and a new submarine cable between Saaremaa and Hiiumaa is needed to create additional spare capacity. With the new submarine cable, it will be possible to connect an additional 4 MW of electricity to the Hiiumaa grid." – ***Kind of proposed measures:*** Main measures are grid investment, replacement of ageing lines, installation of smart meters.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: energy-based, power-based, lump sum – ***Withdrawal charges vary by:*** voltage and time of use. (1) energy-based only, (2) mix of energy-based and power-based, (3) mix of energy-based, power-based and lump sum, households: additionally (4) mix of energy-based and lump sum, MV connected consumers: lower variable tariffs than low V connected consumers, but higher fixed fees, consumers whose electricity consumption is higher can use network services with network charges, which include lower variable fees and higher fixed fees – ***Injection charges basic method:*** power-based, lump sum – ***Injection charges varying by*** voltage – ***Variable network charges differentiated by*** - periods: day of week (weekend/holiday), day/night and peak (only Nov-Mar); specifics: peak-time tariff optional; ToU optional for household users (97%), mandatory for other users (3%); no exclusions; ToU tariffs applied for >90% of D-connected users [season, TOD] – ***Charges for storage:*** no storage facilities connected to the D-grid; gross withdrawal – ***Responsible party of tariff methodology***: tariff values change when DSO submits an application for new tariff values that is approved by NRA – ***Cost recovery based on*** forward-looking cost model – ***Relative weighting of components***: - E > P – ***Cost cascading:*** from transmission to distribution, from transmission to transmission, from distribution to distribution; implicit payment (no separate tariff or tariff element)
Regulation
Type of regulation: rate-of-return with yardstick benchmarking, variable costs, operating costs, depreciation of RAB, justified return on RAB – ***Components of regulatory asset base:*** fixed assets, working capital, leased assets – ***Cost approval/scrutiny***: cost scrutiny (by ESA) – ***Anticipatory investments in asset base:*** none – ***Depreciation method***: For depreciation of fixed assets, a regulatory CAPEX method is used, which differs from accounting depreciation. In regulatory CAPEX accounting, a principle is used in which, from a certain moment in time, fixed assets are divided into two parts: the old ones and the new investments. All assets acquired before the limit year are considered old ones, and an accelerated rate of depreciation is applied for them; (straight-line method) – ***Depreciation time/ratio***: depends on asset type / average depreciation ratio of DSOs is 3.54% – ***Depreciation consideration***: Straight line
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Comparable information tool. "The available capacities map provides an overview of the unused resource of medium voltage power lines. The map is based on calculations of medium voltage lines and shows which lines do not need costly distribution network construction works in order to create a new network connection with the displayed capacity, thus helping to plan connections to more efficient locations in terms of both production and consumption. The capacities shown on the map

are for information only. The display of available capacities takes into account existing electricity producers, pending and undeveloped connections, but does not take into account available capacities between the distribution and the transmission network." – ***Transparency platforms for potential grid users:*** Yes, online map exists: ."The map of available capacities shows indicative information, and the final answer regarding the connection costs can be obtained by submitting a connection application." – ***Unification of requirements among DSOs for grid connection:*** One major DSO Elektrilevi, no need for harmonisation, but standardised process exists for connection. – ***Exemptions to file grid connection requests for*** No exemptions. Grid connection for nano and micro producers and other producers standardised, with easy-to understand connection procedure and tariffs published on DSO website.
Measures in case of lacking capacity
Assignment of grid capacity based on: "first come, first served," formal process for grid connection. Upon submitting documentation, paying the connection fees, producer is connected if there is grid capacity. If there is no capacity, DSO assesses the cost for grid development and user needs to pay this on top. The connection fee is determined during the preparation of the connection offer. If the transmission capacity of the electricity network is not sufficient and needs to be increased, you will also have to pay for the necessary work and equipment and materials. – ***Connection charges with*** Shallow (under 300 m connection) or deep (over 300 m) connection charge based on Individual actual cost (€); Contracted power (€/MW); exemptions: No exemption, discount or difference, variation based on voltage (Yes) and location (No) / Up to 0.79 kW 0 €; up to 15 kW own use only 639 €; over 15 kW actual cost + cost of Elering – ***Conditional grid connection*** none
Process for grid connection requests
Maximum lead time for processing: Up to 0.79 kW: 4 business days; up to 15 kW: 30 days; over 15 kW up to 340 days – ***Unification of process among DSOs*** One major DSO ***Fully digitalized process*** Yes – ***Number of forms per request to submit***: One-stop-shop at DSO, using digital identification. DSO provides information videos, informational materials, FAQ and links to potential grants as well. Looks user-friendly. Ownership registration of property/consent of owner and detailed plan for connection needed.
National grid conditions
Number of DSOs: 34, of which 32 legally unbundled, one over 100 000 customers – ***Ownership structure:*** State owned and private investors – ***Connected customers:*** 0.6 mio. connected customers – ***Length of grid:*** 63 952 km low, mid and high voltage lines ***Average grid age:*** Avg grid age ~30 yrs – ***Policy targets for electric vehicles and of charging stations:*** 82 273 EVs by 2030, 253 048 by 2040, 666 898 by 2050 – RES-E ***share:*** 31.8% in 2023 (of the RES share: 25.0% PV and 25.8% wind) – ***Smart meter rollout:*** 99% smart meter deployment
National particularities
The age of the network implies high investment needs. Near-complete smart meter coverage provides real-time data and supports network planning. The high level of digitalisation allows consumers to make inquiries from home without having to physically visit the DSO's office.

Design features in Finland (FI)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: biennial – ***Public availability:*** Yes – ***Length:*** 30-70 pages – ***Language:*** Finnish, Swedish, English – ***NDP template provided?*** No template, but common structure and required information set in the Finnish Electricity Market Act (588/2013) and by NRA – ***NDP aggregating the DSO NDPs?*** No – ***Threshold for mandatory NDP development***: None – ***Key elements of NDP***: Key investments, capacity map, plan for using flexibility services, appropriate comparisons of cost-effectiveness of

activities, comparison with previous NDP – ***NDP as Legal basis for investments*** Yes, NDP compels the regulator to permit a specified amount of investments, even if such investments are not deemed necessary
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, ***Main deadlines***: consultation for at least one month (1-31 May), DNDP submission 30 June – ***Geographical coverage***: each DSO must cover its entire service area, definition of distribution network development zones with similar characteristics by each DSO – **NRA** monitors, assesses and reviews the NDPs and can request DSOs to make amendments – ***Consultation process***: public consultation process with relevant network users and TSO, included in DNDP, ***Alignment to TSO NDP?*** Yes, Section 19 of the Electricity Market Act mandates cooperation, ***Available data basis from TSO*** yes, cooperation between TSO and DSO
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts NECP, local energy and climate plans (i.e. Helsinki), national and local development forecast – ***Consideration of flexibility by EVs*** Yes, ***HAC*** Yes, ***Other demand*** Yes, some demand response projects, ***Storage*** yes, ***Production curtailment*** No – ***Kind of proposed measures:*** grid reinforcement, demand response, energy efficiency, energy storage facilities or other resources as alternative to system expansion
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Energy-based, power-based, (monthly capacity-based) ***withdrawal charges varying by*** voltage and time-of-use (E- and P-based) ***and exemptions for*** households and small buildings (E-based + lump sum), industrial consumers (lump sum, P-based, reactive power fee, D-fee) – mainly energy-based, in some cases power-based or lump sum ***injection charges varying by*** none at all ***and exemptions for*** small producers by some DSOs – optional ***variable network charges differentiated by*** season, ToD – ***Responsible party of tariff methodology***: individual DSOs –injection and withdrawal ***charges for storage*** – ***Cost recovery based on*** average cost – ***Relative weighting of components***: E>P
Regulation
Incentive-based ***regulation*** (revenue cap, four years regulation period) – ***Components of regulatory asset base*** fixed assets, working capital, leased assets – ***Anticipatory investments in asset base:*** No formal definition, network development is based on long-term, need-based planning– ***Cost scrutiny***: Electricity Market Act mandates cost-effectiveness in both operational expenditures (OPEX) and network development. OPEX is regulated through pricing and the collection of unit prices serves as a form of scrutiny. Further, efficiency, quality, innovation, and investment incentives are considered with changing regulation methods at the beginning of the regulation period. – ***Yardstick benchmark method***: StoNED (Stochastic Non-Smooth Envelopment of Data) – ***Consideration of investment types*** WACC, CAPEX, OPEX – ***Time-dependencies due to base year and regulation period?*** No base year but annual benchmarking – ***Adjustable components during regulation period:*** Inflation adjustment using the average consumer price index
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: national capacity mapping – ***Transparency platforms for potential grid users:*** Capacity maps exist, easy information on PV connection process – ***Unification of requirements among DSOs for grid connection*** yes ***and its standardization based on*** approval from the Energy Authority for the terms of transfer services and connection services and the principles for determining the fees for connection – ***Exemptions to file grid connection requests*** are not predefined according to legislation
Measures in case of lacking capacity

Assignment of grid capacity based on first-come, first-served basis – Shallow ***connection charges*** for small-scale electricity generation (max. 2 MVA) – ***Conditional grid connection:*** No established and confirmed practice
Process for grid connection requests
Maximum lead time for processing: The connection must be connected to the electricity network within 24 months of making the connection agreement – ***Default action in case of surpassing lead time***: no default acceptance - ***Unification of process among DSOs*** No – ***Fully digitalized process*** Requests are submitted and decisions are provided electronically (e.g., by email) – ***Number of forms per request to submit***: one investigation request; for DSOs with digital process: forms are available online, information available on websites; depending on DSO more or less comprehensive
National grid conditions
Number of DSOs: 77 thereof 20 legally unbundled [threshold: 50,000 customers/DSO] – ***Ownership structure:*** State, local public and private (domestically and internationally held) ownership – ***Length of grid:*** 110 kV ~ 16,300 km (TSO (7300 km)& DSO (8900 km)); 1-70 kV ~ 155,200 km (DSO); 0,4 kV ~259,400 km – ***Average grid age:*** there are network parts from 1960s but mostly newer than 1990 – ***Curtailed demand and supply per year:*** none ***of demand*** and 93,000 MWh ***of production*** in2023 – **Network losses**: 1,700-2,000 MWh in 2016 – ***# of electric vehicles***: 118,000 (4.3%) passenger cars (BEV), 4,500 electric vans (1.3%), 960 electric buses and coaches (9%) in 2024; and policy target of 700,000 passenger cars, 45,000 electric vans (half of which all electric) in 2030 – ***# of public charging stations***: [4,204 in 2024 and policy target of 2,000 in 2020 and 25,000 in 2030 – ***# of HAC per HH***: 1.4 Mio. Heat pumps in 2022, 44% of HH in 2020 and no policy target exist but forecasts estimate a growth of yearly 100.000 heat pumps – RES-E ***share***: 52.4% in 2023 (of the RES share: 1.6% PV and 39.3% wind) – ***Smart meter rollout:*** 99.5 % of grid connection points – ***National particularities***: planning, constructing and maintaining of distribution networks have to ensure no outages longer than 36 hours outside urban areas from beginning of 2029, which leads to weatherproofing; this has been under discussion, as it might cause over-investments
National particularities
Finland has an almost full smart meter roll-out driving consumption data available for consumers. However, so far there is a low implementation of flexibility, especially regarding variable tariffs. For the network regulation the method decisions are published before the start of the upcoming regulation period, and these method decisions determine how the allowed or target revenues are set for the period. Regarding anticipatory investments the DSOs are very heterogeneous and no clear definition exists, however it is assumed that smaller DSOs mainly owned by municipalities have a lower risk tolerance, than bigger DSOs with international investors. High engagement in participation of NDP consolidations is due to high interest by electricity consumers, easy and short questionnaire and DSOs have to achieve a certain share of responses, otherwise redo the survey. Some DSOs created an AI to evaluate the responses.

Design features in France (FR)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Biennial reporting – ***Public availability:*** Yes – ***Length:*** 184 pages – ***Language:*** English, French – ***NDP template provided?*** No – ***National NDP aggregating the DSO NDPs?*** No, but one DSO (Enedis) covers >95% of the connections – ***Threshold for mandatory NDP development***: 100.000 clients – ***Key elements of NDP***: Investment trajectories are presented in the NDP, but they are national forecast trajectories and are not binding.
Procedural steps, data collection and governance of NDPs

Obliged by national legislation? Yes, in Article L322-11 of the "code de l´énergie", ***Main deadlines***: [No information] – ***Geographical coverage***: National coverage – **NRA** approves the NDP – ***Consultation process***: The DSO consults all the network users concerned, the public electricity distribution concession authorities, and the TSO concerned on the network development plan. – ***Alignment to TSO NDP?*** Yes, alignment is present, amongst other by means of regional renewable energy master plans (S3REnR). The TSO develops these plans in agreement with the DSOs – ***Available data basis from TSO*** Yes
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts NECP, DSO prospective 2050 study, joint TSO-DSO study, prognose of annual number of connection additions – ***Consideration of flexibility by EVs, HAC, other demand, storage, production curtailment*** All no, NDP scenario does not include flexibility, but in the NDP descriptions of possible flexibility types (and pilots) are mentioned. It mentions "Currently, flexibility potentials appear to be at an early stage of permeation for the distribution network, hence its absence in this NDP baseline trajectory. However, this does not preclude future flexibility resources, and the regular update of the NDP will be an opportunity to re-evaluate this assessment." – ***Kind of proposed measures:*** Mainly grid reinforcements. Pilots on flexibility are mentioned.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Energy-based, power-based (contracted or rated power), and lump sum ***withdrawal charges varying by*** voltage and time of use (MV users: power- and energy-based, low V users < 36 kVA: energy-based) - lump sum ***injection charges varying by*** voltage - optional (for all users who have access to time-of-use) ***variable network charges differentiated by*** periods: seasonal, peak/off-peak; specifics: 16 peak and 8 off-peak hours – ***Responsible party of tariff methodology***: NRA, 4 year regulation period, yearly adjustment – Withdrawal (energy- and power-based and lump sum ***charges for storage*** – ***Cost recovery based on*** incremental costs, the coefficients are adjusted proportionately to recover the charges for historical infrastructure, which deviate from the marginal cost of infrastructure development (multiplicative adjustment) – ***Relative weighting of components***: energy > power
Regulation
Incentive-based revenue cap ***regulation*** – ***Components of regulatory asset base*** fixed assets – ***Anticipatory investments in asset base*** No - ***Cost approval/scrutiny***: Approval by NRA – ***Yardstick benchmark method***: [No information] – ***Consideration of investment types*** non-controllable and controllable costs, depreciation costs, taxes, fair margin
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Comparable information tool – ***Transparency platforms for potential grid users:*** direct customer service for PV by DSO – ***Unification of requirements among DSOs for grid connection*** N/A, one DSO covers 95% of connections ***and its standardization based on*** digital platform – ***Exemptions to file grid connection requests for*** EV charging stations and RE production (especially producers below 36 kVA or for certain big projects with significant impact on the energy transition)
Measures in case of lacking capacity
Assignment of grid capacity based on first-come-first-serve principle usually, but RE production requests can be prioritised under Art. 15 of the law for acceleration of RE production, if located in the "Schemas Regionaux de Raccordement au Reseau des Energies Renouvelables - S3REnR", zones of priority RE development published by the TSO. – Shallow ***connection charges with*** multiple components: Individual actual cost (€), lump sum, distance (€/m), contracted power (€/MW) (variation based on voltage, location, and connection firmness (discounts for interruptible connection agreement.) – ***Conditional grid connection*** Flexible connection agreements were being tried in 2022 with a sandbox: testing flexible connections for DER producers. Legal framework allows the DSO and TSO

to propose a non-firm connection for producers in three distinct cases: 1. “Anticipated connection” / 2. "Alternative offer", 3. "Intelligent offer"
Process for grid connection requests
Maximum lead time for processing: ~2 months (DSO must sent connection proposal within 1 month from receipt of complete connection request, after acceptance of applicant, DSO has one month of connection time) – ***Default action in case of surpassing lead time***: [No information] – ***Unification of process among DSOs*** No (but there is one DSO that represents >95% of the connections) – ***Fully digitalized process*** No, Enedis (the main DSO) has an online platform but the request for can also be done over phone. – ***Number of forms per request to submit***: Enedis (DSO >95% of connections) has an online platform. The procedure is different for homes (simplified for requests under 36kVA), businesses and RE producers (request through the S3REnR scheme).
National grid conditions
Number of DSOs: 138, 1 with >95% of connections (Enedis) – ***Ownership structure:*** Mainly indirect public ownership – ***Length of grid:*** 1.4 million km with 40.2 mio. connected customers - ***Average grid age:*** [No information] – ***Curtailed demand and supply per year:*** [No information] – **Network losses**: 6.4% (2018) – ***# of electric vehicles***: 2.32% BEVs of overall vehicles (2023) – ***# of charging stations***: 119,255 Charge Points (2023) – ***# of HAC per HH***: 16% (2023) of HH, political goal of producing 1 million HPs in France by 2027 – ***RES-E share***: 30.0% in 2023 (of the RES share: 15.5% PV and 33.8% wind) – ***Smart meter rollout:*** 94% of grid connection points
National particularities
Since 2018, Enedis has been offering a data-sharing service to manage collective self-consumption. Furthermore, S3REnR plans (TSO-DSO collaboration, TSO in lead), enables pooling of infrastructure costs with energy producers and local authorities to better integrate renewables.

Design features in Germany (DE)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: biennial – ***Public availability:*** *Yes* – ***Length:*** 10-50 pages – ***Language:*** German – ***NDP template provided?*** No, but common methodology specifying inputs from DSOs (principles and regional scenarios) – ***National NDP aggregating the DSO NDPs?*** Only aggregated expansion plan for the 6 planning regions – ***Threshold for mandatory NDP development***: 100k connections for issuing own NDP; small DSOs need to support DSOs in their planning region (defined by BDEW, the German energy association), not excluded are small DSOs that curtail more than 3% of the yearly generation of their wind and PV plants (§ 14d (8) EnWG) – ***Key elements of NDP***: Focused only on network expansion planning (DNEP), full network development plan by TSOs, mainly overview of DSOs high- and medium voltage network, the status of the planning and approval procedures, the estimated costs and the expected completion date. – ***NDP as Legal basis for investments*** No requirement for approval of the DNEP, but input to NDP which is the legal basis for investments and responsibility of TSOs.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, DNEP for DSOs those with 100k+ customers, NDP then follows formalized legal requirements directed at TSO and NRA, ***Main deadlines***: 31st Oct., lead time of 10 months for publishing of regional scenarios to be used as input – ***Geographical coverage***: Division into 6 regional plans at the distribution network level, with each region having an aggregated expansion plan, based on common national methodology – **NRA** comments, approves and can request amendment for the NDP – ***Consultation process***: Yes for NPD, including publication of consultation process, scenario framework and regional plans. No requirement for consultation process to be public by individual DSOs,

but binding requirement to use regional scenario framework., ***Alignment to TSO NDP?*** Yes, common methodology – ***Available data basis from TSO*** Yes
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts: Regional scenarios developed in line with TSO NDP and under consultation of the NRA and TSOs – ***Consideration of flexibility by EVs*** No, ***HAC*** No, ***Storage*** Yes, with acknowledgement of high uncertainty ***production curtailment*** Not separately specified in regional NDP, receives attention in national Monitoring by NRA – ***Kind of proposed measures:*** Measures developed according to NOVA principle (Network optimization before reinforcement before expansion), but all measures covered. Individual DSOs responsible for network expansion plan in their realm.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Mainly energy-based, static and energy- and power-based for higher voltage customers ***withdrawal charges*** (for low voltage customers, incl. optional lump sum component, for higher voltage levels also power component included) ***varying by*** voltage, variation by time-of-use is planned and applies to controllable consumption units *(§14a EnWG, see grid connection requests)* ***and exemptions for*** storage, grid-friendly controllable consumption units and industrial consumers. Negative (=payback) ***injection charges varying by*** voltage for production units without other subsidy commissioned before 2018/2023 - optional ***variable network charges*** for consumers ***differentiated by*** TOD – ***Responsible party of tariff methodology***: Ministry of economic affairs, updated annually in collaboration with NRA – ***Charges for storage:*** negative injection charge ; withdrawal: E- and P-based – ***Cost recovery based on*** average cost – however: new process for re-distribution of costs for integration across DSOs due to regional disparities in burden of integration starts from 2025 (BK8-24-001-A) – ***Relative weighting of components***: energy- > power-components
Regulation
Revenue-based ***regulation*** with year period for efficiency gains ***Components of regulatory asset base*** are subject to upcoming reform that will change the current pure focus on CAPEX as interest rate cost basis – ***Anticipatory investments in asset base*** not restricted by regulation, however lacking definition imposes risk for DSOs – ***Cost approval/scrutiny***: formal approval by NRA – ***Yardstick benchmark method***: so far DEA the preference (in incentive regulation ARegV), new process has DEA and SFA under consideration, revision process ongoing. – ***Time-dependencies due to base year and regulation period?*** Yes, also under revision. – ***Adjustable components during regulation period:*** Investments in new assets after the base year led to an adjustment of CAPEX (no distinction between replacements or expansions), CAPEX in-period top-up
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Load flow analysis implemented differently across DSOs, often conservative assumptions (e.g. simultaneity factor = 1). Process under revision to allow higher utilization. – ***Transparency platforms for potential grid users:*** Capacity maps mandated by law but not nationally standardized, heterogeneity by DSO. – ***Unification of requirements among DSOs for grid connection*** Yes for handling, no for detailed process ***and its standardization based on*** common platform and new legal obligations – ***Exemptions to file grid connection requests for*** small assets (e.g. charging stations < 11kw)
Measures in case of lacking capacity
Assignment of grid capacity based on Obligation to connect in a transparent and non-discriminating manner (not further specified, no prioritization procedure) – ***Connection charges with*** Shallow connection charge (only direct cost), deep connection charges or rejection of connection for exceptional economic burden – ***Conditional grid connection*** Yes (§17 2(b) ENWG) but not widely applied. More in focus in national debates is that DSOs

can dim assets in case of congestion events in exchange for lower network fees (§14a ENWG).
Process for grid connection requests
Maximum lead time for processing: 2 months standard period, but 1 month for small renewable assets (<30kw since 2024), complex rules and grandfathering for larger assets. – ***Default action in case of surpassing lead time:*** Small assets can be directly connected if DSO does not fulfil legal obligations. – ***Unification of process among DSOs*** *Yes* for requirements (§ 8 Abs. 6 EEG 2023), no for processing with DSOs, but ***based on*** common national register for assets – ***Fully digitalized process*** No, central DSO platform links to websites of each DSO; there strong heterogeneity between the processes – ***Number and length of forms to submit***: strong differences by asset class, pre-conditions and size, in many cases separate procedures when connection involves construction. Exemptions and expeditions for renewable assets ("EEG" assets)
National grid conditions
Number of DSOs: ca. 870 thereof 80 legally unbundled [threshold: 100 k customers/DSO] – ***Ownership structure:*** private and local public ownership – ***Length of grid:*** ca. 1,900 k km (thereof HV grid ~ 96 k km; MV grid ~ 520 k km; LV grid ~ 1,120 k km) – ***Curtailed demand and supply per year:*** 27 TWh (mainly production) in 2023 (thereof 42% RES, 80% caused by transmission & 20% by distribution grid) – **Network losses**: 27 TWh in 2023 – ***# of electric vehicles***: 2.5 mio. in 2023 and policy target of 15 mio. in 2030 – ***# of charging stations***: 120.6 k in 2022 (fast charging > 150 kW: 0.13%) – ***# of HAC per HH***: 1.8 mio. in 2023 and policy target of 6 mio. by 2030 – RES-E ***share***: 52.2% in 2023 (of the RES share: 23.6% PV and 50.7% wind) – ***Smart meter rollout:*** 1.03 % of grid connection points in 2022 and policy target of 95% of targeted groups in 2030
National particularities
Highly heterogeneous DSOs (organizational structure, progress on digitalization, customers base), many exemptions for smaller DSOs to relieve organizational burden. Disbalance between wind power in the north and demand concentration in the south leading to high redispatch costs at transmission level, with repercussions for lower grid levels.

Design features in Greece (GR)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Biennial reporting – ***Public availability:*** Yes – ***Length:*** 92 (+200 Annex) pages – ***Language:*** Greek – ***NDP template provided?*** No – ***National NDP aggregating the DSO NDPs?*** N/A as there is only one DSO – ***Threshold for mandatory NDP development:*** No
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes – ***Geographical coverage***: National coverage (including the mainland grid, the non-interconnected islands and the interconnected islands) – **NRA** approves the NDP, the Ministry of Environment and Energy is involved in aligning the plan with national energy policies and long-term strategic goals. If the development plan affects high-voltage transmission grid, Independent Power Transmission Operator (IPTO) coordination is required. – ***Consultation process***: Public consultation process is executed. Draft NDP is published for public consultation by the DSO on their website. DSO then reviews feedback and submits a revised NDP to the NRA along with a summary of the public consultation process. – ***Alignment to TSO NDP?*** Yes ***Available data basis from TSO*** Yes
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts NECP in terms of electricity demand forecasts, and renewable energy development targets, 10-year IPTO plan for detailed electricity demand and generation forecasts. – ***Consideration of flexibility by EVs*** Yes, ***HAC*** No,

Other demand: demand side management, ***Storage*** Yes – ***Kind of proposed measures:*** Mainly grid reinforcement.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Energy-based, and power-based (actual power at specified time for MV users, contracted or rated power for low V users) ***withdrawal charges varying by*** voltage – No ***injection charges***) – ***Variable network charges:*** mandatory for users who are subject to ToU; users who are not equipped with smart meters are excluded (users with capacity <85 kVA), ToU applied for less than 10% of D-connected users ***differentiated by*** periods: seasonal; specifics: capacity charge applied during predefined peak periods, no charge in other times – ***Responsible party of tariff methodology***: DSO (subject to NRA approval), 4 year regulation period, yearly adjustment - ***Charges for storage:*** no storage facilities are connected to the distribution grid – ***Cost recovery based on*** average cost – ***Relative weighting of components***: energy > power
Regulation
Revenue cap ***regulation*** including a reasonable rate of return on investment – ***Components of regulatory asset base*** Fixed assets, working capital, assets under construction – ***Anticipatory investments in asset base*** No – ***Cost approval/scrutiny***: NRA approval (rolling and sharing mechanism applies on actual controllable OPEX to provide stable incentives for efficiency improvement) –***Consideration of investment types*** OPEX (non controllable and controllable costs), depreciation, RAB (assets and approved investment plans, working capital), WACC and WACC premium – ***Time-dependencies due to base year and regulation period?*** Yes, year 1-2 (actual) and year t-1 (estimates); allowed revenue is adapted to single year regulation periods – ***Adjustable components during regulation period:*** modifications to approved development plans during a regulation period are considered in ex post treatment of CAPEX
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Reporting by DSO via web-based tool – ***Transparency platforms for potential grid users:*** easy information on PV connection process – ***Unification of requirements among DSOs for grid connection*** N/A (only one DSO)
Measures in case of lacking capacity
Assignment of grid capacity based on first-come-first-served queuing system. (When there is insufficient network capacity, the user is placed in a queue and must wait until the required upgrades or expansions are made to the network.) Exceptions are made for critical infrastructure or strategic projects identified by DSO – Shallow and deep ***connection charges with*** fixed and variable components; individual actual cost (€); lump sum; distance (€/m); contracted power (€/MW); variation based on voltage, location, and type of user (producer / consumer) (Typically the connection charges are shallow, covering the costs directly associated with connecting the user to the network up to the point of connection. In cases of large-scale generation projects, deep connection charges may apply, where the user bears the full cost of network reinforcement. This is dependent upon the connection agreement between the DSO and the user.) – ***Conditional grid connection*** Yes. Conditions typically involve network upgrades (if existing grid infrastructure does not have the capacity to accommodate the new user) or pending regulatory approvals (if connection is subject to regulatory or environmental approvals). Conditional connections may also be granted based on specific technical conditions e.g. specific performance standards. Connection remains conditional until all requirements are fulfilled.
Process for grid connection requests
Maximum lead time for processing: varies with the type of connection and complexity. For residential or commercial users (small, medium), it can take up to 6 months assuming no major upgrades are required. For larger connections, this might take up to 2 years. Lead time can be extended. – ***Unification of process among DSOs*** N/A (only one DSO) -

Number of forms per request to submit: There is no 'one-stop-shop' approach in Greece, hence requests and approvals often take longer than the designated times provided above.
National grid conditions
Number of DSOs: 1 (HEDNO) – ***Ownership structure:*** Fully owned by PPC (Public Power Corporation) which is publicly listed and majority state-owned – ***Length of grid:*** 239,232 km with 7.7 mio. connected customers - **Network losses**: 9.7 % (2017) - ***# of electric vehicles***: 0.21% BEVs of overall vehicles (2023), and policy target of 30% in 2030 (BEVs or PHEBs) – ***# of charging stations***: 7k Charge Points (2024) – ***# of HAC per HH***: Heat pump density of 35 per 1000 residents (2024) – RES-E ***share***: 48.2% in 2023 (of the RES share: 33.9% PV and 44.0% wind) – ***Smart meter rollout:*** First phase of smart meter rollout will involve the installation of 3.12m meters between 2023-26.
National particularities
Unique geographical challenges with plethora of small islands and remote regions. These are more expensive to maintain and operate using grid infrastructure. There is a need for robust interconnection with each other and between Greece and its neighbouring regions.

Design features in Hungary (HU)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Annual reporting of 10-years development plans – ***Public availability:*** Yes – ***Length:*** 100 pages + annex – ***Language:*** Hungarian – ***NDP template provided?*** Main elements of methodology and document structure set in Operational Code – ***National NDP aggregating the DSO NDPs?*** Yes, one NDP for the TSO and all DSOs. The network licensees prepare their plans simultaneously, with the lead of the TSO, broken down into content units along common control points. – ***Threshold for mandatory NDP development***: No (there are no small DSOs) – ***Key elements of NDP***: Planned investments are listed per network operator. No capacity maps exist, but allocated capacities for >0.5 MW RES power plants are published on the NRA's website to incentivise colocation. It is planned to create a map based on this list.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes – ***Main deadlines:*** Public consultation starts in December, decision on acceptance in February – ***Geographical coverage***: National coverage – ***NRA's role:*** The NRA approves the DNDPs, no other approval is needed. – ***Consultation process***: Continuous consultation with sectoral stakeholders. The draft NDP is published for public consultation by NRA on its website. The consultation period is one month (January). – ***Alignment to TSO NDP?*** There is one integrated TSO-DSO development plan – ***Available data basis from TSO:*** Continuous data exchange.
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts: National targets and assumptions set by strategic documents (NECP); customer requests of large consumers – ***Consideration of flexibility by EVs, HAC, other demand***, ***storage***, ***production curtailment:*** Injection factors of such technologies are considered as load reducing factors – ***Kind of proposed measures:*** Only grid reinforcements. The integration of flexibility services in line with flexibility market development and the DLR into the NDP methodology is under continuous development and implementation.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: Energy-based, power-based, lump sum – ***Withdrawal charges vary by*** voltage. For low V users <3x80A: only E-based and lump sum, for other users: also P-based. Net withdrawal fees for prosumers <50kW (for 10 years from installation, if the request was made util 09/2023, and the installation is completed until 01/2026) – ***Injection charges vary***

by none (no injection charges) – ***Variable network charges differentiated by*** none (new tariff scheme is available for smart metered PODs from 2025 with 3 time-zones daily – day, peak and off-peak time period –, but these zonal charges are currently identical; plus metered P charge component currently on zero value) – ***Charges for storage:*** Injection: no charge; withdrawal (>3x80A): E- and P-based, lump sum; gross withdrawal – ***Responsible party of tariff methodology***: NRA, yearly – ***Cost recovery based on:*** average cost – ***Relative weighting of components***: E>P – ***Cost cascading:*** from transmission to distribution, from transmission to transmission, from distribution to distribution; implicit payment (no separate tariff or tariff element inside transmission and inside distribution)
Regulation
Type of regulation: Hybrid regulation (revenue caps) with 4 years period (currently 2025-2028), yardstick benchmark (concerning the O&M costs) and quality element. – ***Components of regulatory asset base:*** Fixed assets. Network assets: book value, non-network assets: book value. – ***Cost approval/scrutiny***: NRA determines the fees, which are calculated on the basis of the recognised cost pool. – ***Yardstick benchmark method:*** The efficiency benchmarking involves assessing the operators' individual costs against the services they provide and determining each operator's cost efficiency compared to the other operators. – ***Anticipatory investments in asset base:*** Not mentioned, but practically approved (if completed or planned for the given year) – ***Assessment of network quality:*** SAIDI, SAIFI, outage rate – ***Depreciation method***: Straight line – ***Depreciation time/ ratio***: Depends on asset type – ***Depreciation consideration***: Based on company's accounting policy - ***Time-dependencies due to base year and regulation period?*** Base year for next period: 2023 – ***Adjustable components during regulation period:*** Annual adjustment of network tariffs (The annual network tariff adjustment formula accounts for WACC, inflation (CPI) and wage indices, new investments, forward electricity price changes for network losses, differences between actual and forecasted revenue,); minus connection charges.
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: National level, with coordination of the DSOs – ***Transparency platforms for potential grid users:*** No detailed capacity maps exist, easy information on PV connection process available – ***Unification of requirements among DSOs for grid connection:*** Standardized by law and NRA – ***Exemptions to file grid connection requests:*** None.
Measures in case of lacking capacity
Assignment of grid capacity: Until 2025: pro rata principle, with prioritization of connections to MV network and larger plants (in case of non-small scale power plants); From 2025 (planned): Tender for grid connection by connection points and connection years, organised by the NRA, decisions based on criteria set by the Ministry of Energy (not auction. The winners of the tenders can apply for connection requests at DSOs, but the connection charges must remain cost-reflective – ***Connection charges:*** Shallow and deep connection charge based on Individual actual cost (€); Contracted power (€/MW); exemptions: RES conditional to additional flexible asset deployment (aFRR) ; low V/MV vs HV consumers, variation based on voltage – ***Conditional grid connection:*** Regulatory codes allow for non-firm capacity contracts, but only for a limited circle of system users (new power plants and storage providers) and for a fixed purpose (economic efficiency). DSOs are able to design the contracts with some leeway, but data on these arrangements is barely shared.
Process for grid connection requests
Maximum lead time for processing: 30 days – ***Unification of process among DSOs:*** The procedures are broadly similar but not fully identical. – ***Fully digitalized process:*** Not fully digitalized, but there are digital options for submission of the requests (it is not mandatory by law) – ***Number of forms per request to submit:*** Many documents (e.g. property register sheet, copy of the land registry map, completed application form, declaration of consent to contract, power of attorney for a qualified mechanic, site plan, copy of signature and company certificate (if legal entity), tenancy agreement (if requested by the

tenant), condominium deed of incorporation, site plan prepared by the applicant, profiling questionnaire, commercial acceptance declaration)
National grid conditions
Number of DSOs: 6 legally unbundled DSOs – ***Ownership structure:*** Two 100% state owned, three partially state owned, one private – ***Connected customers:*** 7.5 mio. – ***Policy targets for electric vehicles and charging stations:*** No specific target in the strategy documents – ***Policy targets for HAC per HH***: No specific target in the strategy documents – ***RES-E share:*** 19.5% in 2023 (of the RES share: 76.0% PV and 7.2% wind) – ***Smart meter rollout:*** ~20% smart meter deployment
National particularities
Due to the rapid increase in PV penetration (plans for 2030 have already been reached), TSO and DSOs are facing huge challenges, DSOs also face challenges due to <50 kW rooftop PV penetration on low V circuits. Connection times are very slow, traditional network development needs to evolve, and the better use of the existing network needs to be encouraged. RRFs are accelerating progress, but physical constraints (e.g. lack of sufficient construction capacity) and availability of technicians are limiting the pace of development.

Design features in Ireland (IE)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: biennial – ***Public availability:*** *Yes (announced)* – ***Length:*** not yet available – ***Language:*** English – ***NDP template provided?*** No – ***National NDP aggregating the DSO NDPs?*** only one DSO in Ireland – ***Threshold for mandatory NDP development***: only one DSO in Ireland – ***Key elements of NDP***: no NDP available yet
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, ***Main deadlines***: at least every two years - ***Geographical coverage***: no NDP available yet – **NRA** approves the NDP and can make amendments – ***Consultation process***: public consultation process with all relevant system users and TSO, ***Alignment to TSO NDP?*** Yes, ***Available data basis from TSO*** no NDP available yet
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts no NDP available yet, from “Electricity distribution network capacity pathways consultation report”, base scenario: targets set in Climate Action Plan 2023 for 2030 (51% CO2 emissions reduction in 2030 and zero emissions in 2050) – ***Consideration of flexibility by EVs*** no details yet, DNDP is supposed to include the use of demand response (Art. 22b (3a) S.I. No 20/2022), ***HAC*** see EVs, ***Other demand*** see EVs, ***Storage*** see EVs, ***Kind of proposed measures:*** no information, since DNDP not yet available
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Energy-based, energy-based and lump sum, or energy-based, power-based and lump sum ***withdrawal charges varying by*** voltage, time-of-use (energy-based), available meter ***and exemptions for*** unmetered connections (public lighting), low V Business Customers (maximum demand) → no time-of-use tariffs – no ***injection charges*** – mandatory and optional ***variable network charges differentiated by*** ToD and type of user – ***Responsible party of tariff methodology***: DSO (subject to NRA approval) – withdrawal ***charges for storage*** – ***Cost recovery based on*** average cost – ***Relative weighting of components***: E>P
Regulation
Incentive-based ***regulation*** with cap and collar system (revenue-based), but also other performance incentives associated with continuity of supply, estimated restoration time

accuracy, customer satisfaction, smart metering, stakeholder engagement, worst-served customer, timely issuing of connection offers, visibility, flexibility, DSO/TSO coordination, and independent role of the DSO – ***Components of regulatory asset base*** fixed assets, assets under construction – ***Cost scrutiny***: formal approval by NRA - ***Yardstick benchmark method***: none, price control approach is used – ***Consideration of investment types*** CAPEX and OPEX with flexibility mechanism that allows the DSO to reallocate allowances between OPEX and CAPEX (bi-directional) – ***Time-dependencies due to base year and regulation period?*** No – ***Adjustable components during regulation period:*** uncertainty mechanism in place, which adjusts revenues to address newly identified system requirements (i.e. new domestic connections, pay-as-you-go meters, large customers, low carbon technology, force majeure, system control, low V model); flexibility mechanism (see above); innovation and R&D mechanism
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: individual DSOs initiative – ***Transparency platforms for potential grid users:*** direct customer service for PV by DSO, interactive capacity maps – ***Unification of requirements among DSOs for grid connection*** Yes, only one DSO in Ireland ***and its standardization based on*** common online form available at DSO website – ***Exemptions to file grid connection requests for*** micro-generation < 6 kVA
Measures in case of lacking capacity
Assignment of grid capacity based on "First-come-first-serve" for generation up to 200 kVA, assignment in batches for larger generation sites, i.e. group processing of generator applications – Shallow ***connection charges with*** fixed and variable components – ***Conditional grid connection*** yes, non-firm contracts are used by DSO: conditional connection of DG on MV/HV level where parallel MV/HV transformers are in place. New pilot project planned/started in 2024.
Process for grid connection requests
Unification of process among DSOs Yes, as there is only one DSO – ***Fully digitalized process*** Yes, digital procedure on DSO's website – ***Number of forms per request to submit***: 1 form for generation up to 200 kVA
National grid conditions
Number of DSOs: 1 thereof 1 legally unbundled – ***Ownership structure:*** ring-fenced subsidiary of ESB Group, which is state-owned – ***Length of grid:*** 172,000 km – **Network losses**: 6.75% in 2023 – ***# of electric vehicles***: goal of 175,000 passenger EVs in 2025 and policy target of 30% of private car fleet in 2030 – ***# of HAC per HH***: policy target of 400,000 heat pumps by 2030 – RES-E ***share***: 40.4% in 2023 (of the RES share: 4.6% PV and 84.4% wind) – ***Smart meter rollout:*** 54% of grid connection points in August 2023 and policy target of 100% in 2025
National particularities
Only one DSO and one TSO in the country with high incentives of working together (e.g. in the multi-year DSO/TSO work plan of the joint system operator program)

Design features in Italy (IT)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: biennial – ***Public availability:*** *Yes* – ***Length:*** 200 pages – ***Language:*** Italian – ***NDP template provided?*** No, no template is provided, but ARERA (Italian NRA) offers guidelines that DSOs must follow when developing their NDPs. ARERA also holds DNPs public consultations for all Italian DSOs with > 100,000 connections. – ***National NDP aggregating the DSO NDPs?*** Yes, ARERA (Italian NRA) published aggregated outcomes of the DSOs NDPs in the Annual report. – ***Threshold for mandatory NDP development***:

100,000 connections – ***Key elements of NDP***: Investment table is present. No capacity maps exist. Map with expected regional incremental capacity [MW] and % for 2025 compared to 2022. Geographical maps that visualize expected number of connections per region exist.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, National Legislation requests the development of the DSOs NDPs in DECRETO LEGISLATIVO 210/21, Articolo 25, comma 5, ***Main deadlines***: from 2025 onwards, DSOs every two years submit NDPs for public consultations at the end of March, public consultation lasts at least 42 days, final NDP document is submitted to the Regulator at the end of June of the same year. – ***Geographical coverage***: National coverage. – **NRA** ARERA approves the investment required and can ask the DSOs to make modifications to the submitted NDP. NDPs are also submitted to the Ministry of Environment and Energy Security. – ***Consultation process***: public consultation (6 weeks long) - the DSOs need to submit to the NRA the observations received with indication of the modifications done to the original DNDP, ***Alignment to TSO NDP?*** Yes, there is alignment with National TSO (Terna) in the NDP, data is published at an aggregated level by the NRA, ***Available data basis from TSO*** Yes
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts Fit for 55 (FF55) 2030 -> 55% CO2 emissions reduction in 2030 and zero emissions in 2050 ; Late transition (LT) 2030 and 2040 -> in line with PNIEC (Italian National energy and climate plans) ; Distributed Energy (DE IT) 2040 in line with ENTSO-G and ENTSO-E. – ***Consideration of flexibility by EVs*** Yes, forecast considers load from EV charging stations – ***Other demand*** more efficient domestic lighting and appliances. Other flexibility forecasting is included as part of the four scenarios but not quantified explicitly in table – ***Kind of proposed measures:*** Connection of generation plants & HV MV LV connections; load evolution; improvement of service quality as per NRA continuation & reliability standards; adaptation to environmental regulation; increased resilience; digitalization & technological innovation.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Overall energy-based, power-based, lump sum; ***withdrawal charges varying*** on D-level P-based and lump sum; additionally, E-based for public lightning and public charging points for EVs; ***and exemptions for*** no customers. – No ***Injection charges*** *and* ***no exemptions***, no ***variable network charges.*** – ***Responsible party of tariff methodology***: NRA, regulation period of 8 years, divided into two subperiods of 4 years, yearly adjustment – ***Charges for storage*** free-of-charge capacity increase for small low V clients during night hours and Sunday, injection: no charge; withdrawal: no charge; relevant tariff has no energy-based component, storage is not subject to network tariffs. – ***Cost recovery based on*** average cost – ***Relative weighting of components***: P > E; from transmission to distribution, from distribution to distribution; explicit payment (separate tariff or tariff element).
Regulation
Hybrid ***regulation,*** with a cost-of-service (rate-of-return) regulation applied to the CAPEX and a cap applied to the OPEX (a different regime applies to DSOs with fewer than 25k connections – where allowed OPEX and CAPEX are based on different parameters). The current regulatory framework for distribution will end in 2024 and the conventional treatment of CAPEX and OPEX is expected to shift to a TOTEX approach. – ***Components of regulatory asset base*** fixed assets, working capital, assets under construction. Historical cost for bigger companies. Standard unit cost (sectoral average) for smaller companies. Both are revalued for inflation and are net of depreciation and grants. –***Cost approval/scrutiny***: NRA approval ex-post –***Consideration of investment exists*** for new investments, depreciation, grants. For standard costs, changes in the driver. – ***Time-dependencies due to base year and regulation period?*** Yes – ***Adjustable components during regulation period:*** Allowed revenue is adjusted annually by rewards or penalties

based on performance incentives such as OPEX efficiency improvement, quality of supply and network resilience.
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Third party reporting (e.g. TSO) - ***Transparency platforms for potential grid users:*** No – ***Unification of requirements among DSOs for grid connection*** Yes ***and its standardization based on*** technical requirements defined in Norma CEI 0 -16 'active and passive consumers to the HV and MV electrical networks of distribution Company'.
Measures in case of lacking capacity
Assignment of grid capacity based on time windows: process consists of: Application and Evaluation, Capacity Assessment & Priority Criteria. Priority is given to 1) projects that support the integration of renewable energy sources (RES), electric vehicles (EVs), and other sustainable technologies in line with energy transition goals and 2) transmission grid needs. – Shallow ***connection charges with*** based on Distance (€/m) contracted power (€/MW); exemptions: Consumers vs other network users; small RES/CHP generators and other generators, variation based on voltage. – ***Conditional grid connection*** Yes, flexible connection allows users (e.g. renewable generation plants) to access the grid in a conditional mode. Cable pooling does not exist at distribution level yet, but TSO and NRA are working on a pilot project.
Process for grid connection requests
Maximum lead time for processing Depends on the type of connections: For residential connections under 10 kV, the standard time is 20 days, maximum construction of connection is 30 days; for simple MV connections, it extends up to 40-60 days; and for more complex MV connections, it can extend up to 90-120 days. – ***Default action in case of surpassing lead time***: DSO needs to pay a fee to the connection requestion party, of which the amount depends on the number of days that the standard lead time is surpassed (25 EUR per day if the lead time is within double the standard lead time; 50 EUR per day if the lead time is in between double and three times the standard lead time; 75 EUR per day if the lead time exceeds three times the standard lead time). – ***Unification of process among DSOs*** No – ***Fully digitalized process*** Yes, digital procedure in DSOs homepage (at least for e-distribuzione). – ***Number of forms per request to submit*** residential connections (<10 kV) standard time is 20 days, simple MV connections standard time can extend up to 40 - 60 days, more complex MV connections can extend up to 90-120.
National grid conditions
Number of DSOs: 123 (8 with more than 100k connections, 4 with more than 500k connections), 1 that covers >85% of connections: e-distribuzione – ***Ownership structure:*** Mainly private and local public ownership – ***Length of grid:*** 1.2 million km with 37.1 mio. connected customers - ***Curtailed demand per year:*** *4 TWh (2022)*– **Network losses**: 7.1% (2017) – ***# of electric vehicles***: 0.58% BEVs of total vehicles (2023) – ***# of charging stations***: 54k Charge Points (2024) – ***# of HAC per HH***: 14% (2023) – RES-E ***share***: 38.1% in 2023 (of the RES share: 25.6% PV and 18.8% wind) – ***Smart meter rollout:*** 99.6% smart meter deployment.
National particularities
High number of DSOs with regional variations, high penetration of DER. DSOs in Italy are transitioning from passive to active network management. There is a strong emphasis on coordination between DSOs and TSO to manage grid stability and integrate ancillary services.

Design features in Latvia (LV)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Annual reporting, 10 year plan (2024-2033) to be replaced with biennial reporting – ***Public availability:*** Yes – ***Length:*** 55 pages – ***Language:*** Latvian – ***NDP template provided?*** No, but the Latvian "Regulation Regarding the Electricity Transmission System Development Plan" Law lists the requirements. – ***National NDP aggregating the DSO NDPs?*** Yes, One major DSO. – ***Threshold for mandatory NDP development***: 100 000 customers – ***Key elements of NDP***: demand scenarios, KPIs (SAIDI, SAIFI, outages), new connections, EVs, PV, investment plan.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes. *Decision No. 1/5/LV of the Public Utilities Commission of 28.05.2020* required the development of DNDP, ***Main deadlines:*** DSO submits the DNDP by 31 August. Regulator sets up a public consultation within 3-7 business days for all interested parties. The Regulator approves or refuses the plan and makes request for modification. If modifications are needed, Regulator sets deadline for the new plan to be re-submitted. – ***Geographical coverage***: National coverage – ***NRA's role:*** Regulator approves explicitly – ***Consultation process***: Public consultation required by the abovementioned National legislation, ***Alignment to TSO NDP?*** No indication of alignment with TSO part from public consultation, ***Available data basis from TSO:*** National Energy Strategy, TSO Ten-Year Network Development Plan (TYNDP) are consulted
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts: 3 scenarios, Crisis/optimist/base electricity demand (DNDP assumption) – ***Consideration of flexibility by EVs, HAC, other demand***, ***storage***, ***production curtailment:*** No explicit flexibility modelling – ***Kind of proposed measures:*** Grid reinforcement, improve quality (SAIDI, SAIFI, outages), development of a smart distribution grid, smart metering.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: energy-based, power-based (contracted or rated power) – ***Withdrawal charges vary by*** voltage – ***Injection charges vary by*** none, microgenerators <11.1 kW are exempted – ***Variable network charges differentiated by periods:*** No ToU tariffs, previous tariff system was streamlined and ToU tariff were scrapped – ***Charges for storage:*** no storage facilities are connected to the D-grid – ***Responsible party of tariff methodology***: NRA – ***Cost recovery based on:*** average cost – ***Relative weighting of components***: E > P – ***Cost recovery through injection tariff:*** 0.2% – ***Cost cascading:*** from transmission to distribution, from transmission to transmission, from distribution to distribution; implicit payment (no separate tariff or tariff element)
Regulation
Type of regulation: revenue-cap with 2-5 years period including OPEX and CAPEX– ***Components of regulatory asset base:*** fixed assets, intangible investment (does not include inventories and assets under construction) – ***Cost approval/scrutiny***: ex-post treatment of capital costs. Book value as per financial reports (taking into account asset revaluations carried out before 31st December 2021 by the operator at replacement cost value) – ***Anticipatory investments in asset base:*** Tariffs are based on justified historical costs and forecast of any other future costs (taking into account official forecast of inflation) – ***Depreciation method***: According to International Accounting Standards (IAS) and operators accounting policy (straight line is mostly applicable) – ***Depreciation time/ ratio***: depending on asset type – ***Depreciation consideration***: depreciation is a part of capital costs in the tariff – ***Time-dependencies due to base year and regulation period?*** no RAB

adjustments during RP; WACC is set yearly – ***Adjustable components during regulation period:*** none
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: One DSO reporting – ***Transparency platforms for potential grid users:*** Easy information on connection process – ***Unification of requirements among DSOs for grid connection:*** One DSO –***Exemptions to file grid connection requests:*** None.
Measures in case of lacking capacity
Assignment of grid capacity based on FCFS – ***Connection charges:*** Deep connection charge based on Individual actual cost (€); Nominal current; exemptions: Smaller network users vs other network users, variation based on voltage – ***Conditional grid connection*** none
Process for grid connection requests
Maximum lead time for processing: Approximately 60 days. Connection can take few days or several months – ***Unification of process among DSOs:*** One DSO. Digital platform for connection (e-st.lv) – ***Fully digitalized process:*** Yes – ***Number of forms per request to submit***: One-stop shop, average citizen can manage without help. If further network development is needed, DSO selects and dispatches contractor for network development.
National grid conditions
Number of DSOs: 11, of which 1 legally unbundled with over 100 000 customers – ***Ownership structure:*** Public and private ownership – ***Connected customers:*** 1.1 mio. ***# of electric vehicles***: 5300 EVs by end of 2023 – ***# of charging stations***: create 2000 charging points for EVs by 2030 – ***# of HAC per HH***: No indication on heat pumps or HAC in DNDP – RES-E ***share***: 54.3% in 2023 (of the RES share: 6.1% PV and 6.0% wind) – ***Smart meter rollout:*** 99% smart meter deployment
National particularities
Technical grid condition related to older Russian network configuration with huge, under-utilized network, which need to be financed. New connections are sited in other parts of the network. There are no signals or price incentives for grid users to site their connection to parts of the grid where there is ample capacity. Demand side flexibility issues are not integral part of system planning.

Design features in Lithuania (LT)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Biennial reporting, 10-year plan (2024-2033) – ***Public availability:*** Yes – ***Length:*** 47 pages – ***Language:*** Lithuanian – ***NDP template provided?*** No – ***National NDP aggregating the DSO NDPs?*** No other DSOs; document took into consideration the Ignitis Group strategy and other country-level strategic documents. – ***Threshold for mandatory NDP development***: 100 000 customers – ***Key elements of NDP***: Map visualising investment need in 10 kV and 35 kV network exists
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, Art 39 (2) of Republic of Lithuania Law on Electricity – ***Main deadlines:*** 10-year distribution network development plan, to be updated every 2 years, submitted by 1st December after public consultation for Regulator NERC – ***Geographical coverage***: National coverage – ***NRA's role:*** After public consultation, NRA approves the DNDP. – ***Consultation process***: Public consultation was performed with TSO and other stakeholders; materials were available online in national language. The final DNDP along with the Q&A is available online. – ***Alignment to TSO NDP?*** LITGRID TYNDP and NECP was considered – ***Available data basis from TSO:*** TSO TYNDP

The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts: Base scenario: historical trends extrapolated; NECP roadmap scenario: accelerated electrification and heat pump installation as suggested by NECP and other strategic documents. – ***Consideration of flexibility by EVs, HAC, other demand***, ***storage***, ***production curtailment:*** Consideration of flexibility conditional on smart metering data. ESO assessed the flexibility of heat plants in urban Vilnius area, which was found not available due to current regulation. As for other types of flexibility, not explicitly considered. EV not considered. – ***Kind of proposed measures:*** Grid reinforcements, which relate to replacement of ageing network as well as connection of new customers due to increased electrification. Roll-out of smart meters allows for better network management.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: energy-based, power-based, lump sum – ***Withdrawal charges vary by*** voltage and time of use (energy-based) – ***Injection charges vary by*** not applied – ***Variable network charges differentiated by*** peak hours – ***Charges for storage:*** injection: no charge (no storage facilities connected yet); withdrawal: E-based; gross withdrawal. Batteries <1MW exempted from all network tariffs; Batteries >1MW: the energy for charging the battery, which later will be used for T-network stability is not charged with T-tariff nor D-tariff – ***Responsible party of tariff methodology***: NRA, yearly – ***Cost recovery based on:*** average cost – ***Relative weighting of components***: E > P – ***Cost cascading:*** from transmission to distribution, from distribution to distribution; implicit payment (no separate tariff or tariff element)
Regulation
Type of regulation: price cap with 5 year regulatory period, quality element and TOTEX, RAB, WACC, technical losses considered – ***Components of regulatory asset base:*** fixed assets– ***Cost approval/scrutiny***: cost approval by NRA – ***Assessment of network quality:*** SAIDI, SAIFI– ***Depreciation method***: straight line –***Depreciation time/ ratio*****:** depending on asset type– ***Depreciation consideration*****:** all depreciation of regulated assets is integrated into revenues – ***Adjustable components during regulation period:*** the regulated price caps are adjusted each year following a change of the inflation rate (OPEX), new investments, depreciation and change of WACC (CAPEX), the electricity price (technical losses) and the ROI adjustment from previous period.
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: quotas and priorities assigned at TSO level, then this allocation is assigned to the DSO grid. RECs among the priorities, to prevent commercial producers from taking all capacity. – ***Transparency platforms for potential grid users:*** Grid maps on ESO site. Seminars & workshops about PV installation & grid. – ***Unification of requirements among DSOs for grid connection:*** Standard IT platform for grid connection and flowchart of tasks to be done at the website of DSO exist. – ***Exemptions to file grid connection requests:*** None.
Measures in case of lacking capacity
Assignment of grid capacity based on FCFS – ***Connection charges:*** Shallow and deep connection charge; exemptions: No exemption, discount or difference, variation based on voltage – ***Conditional grid connection:*** None
Process for grid connection requests
Maximum lead time for processing: Can take 3 months or longer – ***Unification of process among DSOs:*** One major DSO, no need for unification – ***Fully digitalized process:*** Digital platform for submitting requests, standardised process – ***Number of forms per request to submit:*** One-stop shop, average citizen can complete without help. Owner's consent/ownership papers, contractor's permit and documentation electrical wiring

National grid conditions
Number of DSOs: 5, of which 1 legally unbundled, with over 100 000 customers – ***Ownership structure:*** State owned, private investors – ***Connected customers:*** 1.9 mio. connected customers – ***Policy targets for electric vehicles and of charging stations:*** Base scenario: +13 000 EV charging stations by 2033; NECP roadmap scenario: +190 000 EV charging stations by 2033; 8700 EV charging station in 2023 – ***Policy targets for HAC per HH***: Base scenario: 185 000 heat pumps by 2033; NECP roadmap scenario: 279 000 heat pumps by 2033; 80 000 heat pumps in 2023 – RES-E ***share:*** 36.5% in 2023 (of the RES share: 15.3% PV and 57.1% wind) – ***Smart meter rollout:*** 58% smart meter deployment
National particularities
Major replacement of overhead lines with underground cables and smart-meter rollout to ensure better planning and operation of the grid. Network investments enhance the possibility of integration of renewables.

Design features in Luxembourg (LU)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: biennial – ***Public availability:*** Yes, Creos, TSO and largest DSO, will submit the first DNDP to the NRA in autumn 2025 – ***Language:*** English – ***NDP template provided?*** No template provided, but the NRA works on a document with recommendations for DNDP creation, currently under private consultation, to be published. – ***National NDP aggregating the DSO NDPs?*** No – ***Threshold for mandatory NDP development***: Unclear, but ministry has asked all DSOs to set up a plan – ***Key elements of NDP***: Investment plans with concrete projects, costs, timeline and purpose and potentially CBA for 110 kV and 65 kV. For 20 kV identification of weak points.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, ***Main deadlines***: Scenario development in one year, development plan in next year – ***Geographical coverage***: Basically national coverage due to size of largest DSO, smaller DSOs responsible for their grids – The **NRA** has to approve the scenarios as well as the actual plan. It may make recommendations to the network operators with a view to modifying their plan. – ***Consultation process***: Public consultation executed by DSO (1 month). System operators shall consult all relevant system users and the relevant (extra) high voltage system operator – ***Alignment to TSO NDP?*** Creos as the largest DSO and TSO aligns the plans internally, TSO Creos must also be consulted by other DSOs, ***Available data basis from TSO*** Yes, because TSO is also largest DSO and transmission and distribution NDPs shall also be based on the NECP.
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts: DNDPs shall be based on the NECP – ***Consideration of flexibility by EVs*** Yes, ***HAC*** Yes, ***Other demand*** Yes, demand side management, dynamic line rating, ***Storage*** Yes, ***Production curtailment*** Yes – ***Kind of proposed measures:*** Main result: Grid reinforcement investment lists. Grid optimisation and strengthening measures before expansion. Flexibility services are considered by a reduction of the load forecasts based on the identified load forecast. Stakeholders are being approached to identify the technical potential and actual willingness to flexibly steer their electricity demand. Dynamic line rating is applied.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Energy-based, for higher voltage customers also power-based, for low voltage level higher energy-based network tariff for all energy consumed above a specific power level threshold ***withdrawal charges varying by*** voltage (All customers with lump sum payments for

metering) –***Injection charges:*** No – ***Variable network charges:*** None – ***Responsible party of tariff methodology***: NRA, 4 year regulation period, yearly adjustment – Withdrawal (energy-based) ***charges for storage*** however no storage facilities connected yet to distribution network – ***Cost recovery based on*** average cost – ***Relative weighting of components***: energy > power
Regulation
Incentive-based revenue cap ***regulation*** with 4 year period – ***Components of regulatory asset base*** fixed assets – ***Anticipatory investments in asset base*** [No information] – ***Cost approval/scrutiny***: NRA approval – ***Yardstick benchmark method***: [No information] – ***Consideration of investment types*** Revenue cap based on value of regulated asset, WACC, depreciation, operating expenses –– ***Adjustable components during regulation period:*** annual review of the maximum allowed revenue, RAB remuneration, work in progress remuneration, depreciation, quantity factor and indexes for controllable costs and specific pass-through items will be adjusted.
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities/ Transparency platforms for potential grid users: Grid capacity maps are under development – ***Unification of requirements among DSOs for grid connection*** Every DSO has its own procedures. Application process between Creos offering a fully digitalised process and Sudenergie are quite different based on their respective websites – ***Exemptions to file grid connection requests:*** At Creos, all connections require a request, but timelines and application processes are different. For EVs in single family homes, 11kW are always granted permission. Calculations for multi-family homes necessary. For PV, the electrician decides whether he involves Creos to identify the technically correct connection applications or if he is experienced enough to just receive a digital approval based on documentation and photos.
Measures in case of lacking capacity
Assignment of grid capacity based on First-come-first-serve. At Creos, capacities are initially reserved for one year (shall be reduced to six months) and will be extended by one year each time documentation is submitted on the project actually being continued – Shallow ***connection charges with*** individual actual cost (€), lump sum; (€) contracted power (€/MW) components (variation based on voltage and location) – ***Conditional grid connection:*** There are existing cases where exemptions from the current legal framework have been made. These include the connection of certain bus depots, where a higher connection capacity during night-time was allowed for fleet charging, to allow for greater utilisation of the grid. It is expected that these exemptions will form the basis for future legislative amendments concerning flexible connections
Process for grid connection requests
Maximum lead time for processing: Depends on technology, for PV 3 weeks – ***Default action in case of surpassing lead time***: For PV, if no reaction after 3 weeks, plant can be connected – ***Unification of process among DSOs*** Every DSO has its own procedures. Creos, largest DSO, offers a fully digitalised process. Technical connection conditions, drawn up jointly by the DSOs and approved by the NRA, apply for all DSOs. – ***Fully digitalized process*** Biggest DSO Creos uses online platform – ***Number of forms per request to submit***: 4-5 documents needed for households: complete building permit, extract from the cadastral plan, site plan, basement plan for a single-family house or, in the case of a residence, a plan of the technical room as well as a plan of the basements, certificate from the Electricity Service issued by the Architect's Administration (for connections within the territory of the City of Luxembourg)
National grid conditions
Number of DSOs: 5 thereof 1 with more than 100k customers: Creos (which also covers >95% of customers) – ***Ownership structure:*** Mainly direct and indirect public ownership –

Length of grid: 11,374 km with 0.3 Mio. connected customers – ***Average grid age:*** [No information] – ***Curtailed demand and supply per year:*** [No information] – **Network losses**: 3.7% (2018) – ***# of electric vehicles***: 5.62% of overall vehicles (2023), target of 49% by 2030 mentioned in NEPC – ***# of charging stations***: 3,078 Charge Points (2024) – ***# of HAC per HH***: 1% of HH (2019), no policy target – ***RES-E share***: 18.0% in 2023 (of the RES share: 24.7% PV and 36.4% wind) – ***Smart meter rollout:*** 98.9 % of grid connection points.
National particularities
Biggest DSO and TSO are the same entity (Creos).

Design features in Malta (MT)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Biennial reporting – ***Public availability:*** Documents from Enemalta (DSO) not found and not publicly available. Until 2024, Enemalta has failed to file a NDP in line with the requirements expressed in the national legislation (S.L. 545.34). The reporting requirement had not been enforced by the Regulator (REWS). The National Audit Office (NAO) has published a High-Level Review of Enemalta's Planning and Investment in the Local Electricity Distribution Network, highlighting the need for stronger planning function by Enemalta. NAO was forwarded with two plans covering periods 2022-2027 and 2024-2031 (both not publicly available): the 2022-2027 plan is an undated four-page document while the 2024-2031 document is more extensive. Both documents have not been made publicly available. – ***Length:*** no NDP documentation available – ***Language:*** no NDP documentation available ***NDP template provided?*** No – ***National NDP aggregating the DSO NDPs?*** N/A (only one DSO) – ***Threshold for mandatory NDP development***: N/A (only one DSO) – ***Key elements of NDP***: Not available, the DSO NDP is not publicly available.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, by National Legislation S.L. 545.34 – ***Main deadlines***: Not publicly available – ***Geographical coverage***: national coverage – **NRA** approves the NDP – ***Consultation process***: consultation process is not defined neither in the national legislation (S.L. 545.34) nor in DSO/NRA website
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts Enemalta used peak demand forecast modelled by the Energy & Water Agency (EWA) in 2019. – ***Consideration of flexibility by EVs, HAC, other demand, storage, production curtailment:*** Information is not available as Enemalta has not made NDP publicly accessible. – ***Kind of proposed measures:*** Information is not available as Enemalta has not made NDP publicly accessible.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Energy-based (actual maximum power) and lump sum ***withdrawal charges varying by*** time-differentiated kWh or kVAh tariff for consumers > 5GWh, kVAh tariff instead of kWh tariff possible for non-residential premises service consumers with rated capacity > 100 A – lump-sum ***injection charges*** – ***Variable network charges differentiated by*** periods: EV charging: day of week (weekend), outside off-peak (normal charges) and off-peak, large consumers: day/night; specifics: only for EV charging points and non-residential consumers > 5000 MWh or 5500 MVAh. Users with consumption <5 GWh/y are excluded; EV charging points without capable meter are excluded. – ***Responsible party of tariff methodology***: DSO (subject to NRA approval), 5 year regulation period, yearly adjustment - withdrawal (energy and power based) and lump sum ***charges for storage*** – ***Cost recovery based on*** average cost – ***Relative weighting of components***: energy > power.
Regulation

Rate of return ***regulation*** with incentive/price-cap. – ***Anticipatory investments in asset base*** No – *Disclaimer: Please note that obtaining comprehensive information on tariff regulation in Malta proved challenging due to limited availability of online sources.*
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: National capacity reporting. – ***Transparency platforms for potential grid users*** HV distribution system map is present on Enemalta website. Enemalta has a live outage map. – ***Unification of requirements among DSOs for grid connection*** N/A (only one DSO) – ***Exemptions to file grid connection requests for*** RES.
Measures in case of lacking capacity
Assignment of grid capacity based on Obligation to connect in a transparent and non-discriminating manner (not further specified, nor prioritisation procedure established). – Shallow and deep ***connection charges*** based on Individual actual cost (€); lump sum (€); contracted power (€/MW); exemptions: Smaller network users vs. other network users, variation based on voltage (No) and location (No). – ***Conditional grid connection*** yes, available for renewable energy systems and EV meter with prior regulator approval.
Process for grid connection requests
Maximum lead time for processing between 16 and 36 working days – ***Unification of process among DSOs*** N/A (only one DSO) – ***Fully digitalized process*** Yes, online form and approval from regulator for RES and EV meters. – ***Number of forms per request to submit***: online forms and customer service assistance is available. Average expected administrative burden.
National grid conditions
Number of DSOs: 1 (Enemalta) – ***Ownership structure:*** Local public ownership (public by law). ***Length of grid:*** 2,000 km with 0.3 million connected customers –**Network losses**: 6.2% (2023) of total electricity output – ***# of electric vehicles*** 1.13% BEVs of overall vehicles (2023) – ***# of charging stations*** 113 Charge Points (2024), aim to increase the number of public charging points to 1,572 – ***# of HAC per HH***: Average of 78 heat pumps per 1000 residents, no policy target – RES-E ***share***: 10.7% in 2023 (of the RES share: 97.0% PV and 0.0% wind) – ***Smart meter rollout:*** 93.39% smart meter deployment.
National particularities
Until 2024 the DSO Enemalta failed to comply to the national legislation, by not submitting any forms of NDP to the regulator. The regulator RWES has not enforced requirements / issued penalties. In 2024, the DSO has submitted a first NDP for the period 2024 – 2031. Even though national legislation requests the DSO to publish the NDP on its website, the NDP is not available there.

Design features in the Netherlands (NL)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Biennial reporting – ***Public availability:*** Yes – ***Length:*** 125-202 pages – ***Language:*** Dutch – ***NDP template provided?*** No template is provided, but a legally binding document with information to be presented exists – ***National NDP aggregating the DSO NDPs?*** No, but the regulator does provide a letter to the Ministry with a summary of key elements per DSO DNDP – ***Threshold for mandatory NDP development***: No – ***Key elements of NDP***: Capacity maps and geographical maps that visualise investments per region exist. NDP includes table with planned investments up until substation level.
Procedural steps, data collection and governance of NDPs

Obliged by national legislation? Yes, Elektriciteitswet 1998 Art. 21. requests all system operators to develop 'Investeringsplannen' (=Investment plans / DNDPs), ***Main deadlines***: DSOs must publish the draft DNDP for consultation to stakeholders by November / December, for a period of 4 weeks. They must then submit the draft DNDP to the NRA and the Ministry latest on the first of January. The NRA then has 12 weeks to review the draft DNDPs. In this period the NRA can submit additional information requests to the DSOs. – ***Geographical coverage***: Per DSO region – **NRA** approves the NDP – ***Consultation process***: Public consultation process is executed. In an Annex to the DNDPs, DSOs provide responses to consultation inputs from all types of stakeholders ('Zienswijze'), ***Alignment to TSO NDP?*** Yes, shared scenarios are used, ***Available data basis from TSO*** Yes
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts PBL calculations, RES-region bids, SDE subsidy requests, public and private project developments, system studies (i.e. II3050 system study and pMIEK (provincial multiyear program infrastructure energy and climate)), ElaadNL expectations on growth of EVs – ***Consideration of flexibility by EVs*** Yes, ***HAC*** Yes, ***Other demand:*** demand response from industry, power-to-gas – ***Storage*** Yes– ***Kind of proposed measures:*** Mainly grid reinforcements. Based on the 'National Action Plan Congestion' (LAN), new types of contracts are suggested, with 'group contracts' as first contract type that is desired to be provided. Flexibility markets and 'cable pooling' offering for wind and solar generation projects are being used.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Energy-based, power-based (contractual and actual power) and lump-sum ***withdrawal charges varying by*** voltage – lump-sum ***injection charges varying by*** voltage - Optional (only for non-households > 3 x 80A in low V network (very limited in application)) ***variable network charges differentiated by*** periods: day of week (weekend), normal/low tariff (energy based) – ***Responsible party of tariff methodology***: NRA, regulatory period of 3 – 5 years, yearly adjustment – withdrawal (energy and power-based) and lump sum ***charges for storage*** – ***Cost recovery based on*** average cost – ***Relative weighting of components***: power > energy
Regulation
Incentive-based price-cap ***regulation*** – ***Components of regulatory asset base*** Fixed assets and certain intangible assets (such as software) are included, no working capital – ***Anticipatory investments in asset base*** No – ***Cost approval/scrutiny***: NRA approval (ex-ante) - ***Yardstick benchmark method***: yardstick competition is used to determine static efficiency parameters – ***Consideration of investment types*** CAPEX, OPEX and WACC – ***Time-dependencies due to base year and regulation period?*** Yes – ***Adjustable components during regulation period:*** WACC is adjusted yearly, X-factor for efficiency adjustments.
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Individual DSOs initiative – ***Transparency platforms for potential grid users:*** (online) capacity maps are available – ***Unification of requirements among DSOs for grid connection*** Yes ***and its standardization based on*** common regulation and platform
Measures in case of lacking capacity
Assignment of grid capacity based on first-come-first-served generally, however in areas with congestion, as of 2024, DSOs can apply a predetermined priority framework.

The framework has 3 domains: 1) congestion relievers; 2) safety; 3) basic needs (e.g. drinking water, schools) – Shallow ***connection charges with*** individual actual cost (€) or lump sum (€) distance components – (no differences based on voltage or location) – ***Conditional grid connection*** DSOs can enter 'dispatch limitation contracts' with system users to temporarily limit the use of their contracted firm capacity.
Process for grid connection requests
Maximum lead time for processing: For requests regarding new connections < 3 x 80 A: Within 18 weeks after connection request; for requests regarding new connections > 3 x 80 A: maximum lead times differ based on complexity and possible use of a 'dynamic regional waiting time' – ***Default action in case of surpassing lead time***: For requests regarding new connections < 3 x 80 A: prolongation of lead time to 52 weeks; for requests regarding new connections > 3 x 80 A: depends on complexity – ***Unification of process among DSOs*** Yes ***based on*** a common online platform where one can request a grid connection. The platform is not only shared between all DSOs, but also other public utilities (e.g. water, sewage) – ***Fully digitalized process*** Yes – ***Number of forms per request to submit***: Unclear how many forms need to be filled in. It seems that there is one point of contact (the digital platform) and that all information requests need to be entered in here.
National grid conditions
Number of DSOs: 6 thereof 3 with more than 100k customers – ***Ownership structure:*** Municipality (and province) owned – ***Length of grid:*** 257,671 km with 9.0 mio. connected customers –**Network losses**: 4.7% (2018) – ***# of electric vehicles***: 4.95% BEVs of overall vehicles (2023) – ***# of charging stations***: 174k Charge Points (2024) – ***# of HAC per HH***: 7% of HH (2023), no policy target– ***RES-E share***: 46.4% in 2023 (of the RES share: 36.5% PV and 50% wind) – ***Smart meter rollout:*** 90% of grid connection points.
National particularities
The DSO (& TSO) industry organisation ('Netbeheer Nederland') has a taskforce that focuses on harmonisation of DNDPs.

Design features in Poland (PL)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: reporting period of DNDPs min. 6 years, biennial updates – ***Public availability:*** Yes, on DSOs' websites – ***Length*** 10-100 pages, national language. – ***NDP template provided?*** Yes, template ("questionnaire") for 2026-2031 provided for the 5 big unbundled DSOs, this structure will be mandatory for the next update. Currently DNDPs have very diverse structures. For small DSOs for small DSO-s (<100.000 customers) no template, but a special "guideline". The five big DSOs and the TSO coordinate for the 110 kV grid. – ***National NDP aggregating the DSO NDPs?*** No – ***Threshold for mandatory NDP development***: min. 100.000 customers – ***Key elements of NDP*** Different in each DNDP, some are very detailed with demographic analysis, risk analysis, use of external funds, etc., others only contain an investment plan. Only a grid capacity map at TSO level is fully publicly available.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, the main legal basis is Article 16 of the Act of 10 April 1997 (Energy Law) - ***Main deadlines*** deadline for submitting the NDP and its update to URE: 30 April of given year, prior to submission: public consultation of min. 21 days – ***Geographical coverage***: Each DSO's plan pertains to its specific service area. – **NRA's role:** URE (NRA) approves the draft DNDPs and its updates (in consultation with the minister responsible for energy) (no URE and ministry approval for DSOs supplying less than 300 customers). Updates need to be in line with the assumptions resulting from the "KET

Charter" (task force initiated in 2021 by the president of the NRA to implement transparent distribution electricity policy). – ***Consultation process:*** public consultation process of binding nature. The draft DNDP the updates have to be consulted with interested parties prior to the submission to URE's president. Consultation results need to be made available on the DSO websites. A summary has to be presented to the NRA president – ***Alignment to TSO NDP?*** Plans for the development of the transmission grid and the 110kV distribution network are coordinated between TSO and the 5 biggest DSOs.

The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings

Basis for load and production forecasts: The deadline to submit the national Network Codes on Demand Response falls only in March 2025. The current template provided by the NRA does not include the section on DR. **Models applied for forecasts:** Data supplied in the NDP needs to be consistent with data supplied to the NRA for tariff approval (otherwise justification needed). – ***Consideration of flexibility in forecasting*** No, but DNDPs acknowledge the need for more flexibility due to more distributed generation. The flexibility needs assessment required by Art 19e of the EMD is due by April 2025, since the template for DNDPs does not include such a section, DSOs are currently not providing the input data. It was flagged by PTPiREE and the Regulator. DSOs are waiting now for the Network Code on Demand Response template as a guideline on how to collect such data.
Kind of proposed measures: Modernisation of the outdated existing grid infrastructure, smart grid technologies to improve energy management, reducing losses and increasing network efficiency; smart grids for flexible demand side management; AFIR - charging capacity expansion; large-scale and household-level storage; digitalisation and automatization.

Appropriate network tariff regimes and regulatory incentives

Tariff structure

Charges for withdrawal overall energy-based, power-based (contracted or rated power), lump sum; variation by voltage level and ToU, no locational variation. – ***Injection charges*** never applied ***Reactive energy charges*** both for transmission and distribution charges – ***Variable network charges differentiated by*** periods: seasonal (2), day of week (weekends/holidays), peak/off-peak (3, 2 peak, 1 off-peak); set by individual DSO. Mandatory for HV network users when DSO only offers ToU tariff groups (10%), optional for others (>90%); no user is excluded; ToU applied for 10%-25% of D-connected networks users – ***Responsible party of tariff methodology***: URE (NRA) ***update frequency*** 1 year ***additional regulation*** capacity fee (surcharge) set by the law is applied to all end users, depending on whether the withdrawal is similar in peak and off-peak hours or not. – ***Treatment of storage facilities*** no injection charges; withdrawal E- and P-based, lump sum; no differentiation / exemption – ***Treatment of prosumers*** no injection charge, E- and P-based and lump sum, prosumers pay the same withdrawal charges as consumers but can withdraw 70-80% of the energy they inject into the grid free of charge. – ***Cost recovery based on*** average cost – ***Relative weighting of components***: E>P – ***Cost cascading*** from transmission to distribution, from distribution to distribution; implicit payment (no separate tariff or tariff element)

Regulation

Regulatory regime Mixed (cost of service with elements of revenue cap and elements of quality regulation), currently one year, but will be updated, quality element, return on capital (determined also by quality regulation factors) and OPEX, depreciation, property taxes, losses and pass-through costs – ***Components of regulatory asset base*** Fixed assets, assets under construction, intangible assets – ***Regulatory asset value*** re-evaluated assets – ***Links with NDPs*** The energy enterprises involved in the transmission or distribution of electricity prepare network development plans for their area of operation in terms of satisfying current and future demand for electricity, for a period not shorter than three years. This excludes the TSO that must prepare the plan for a ten-year period, and DSOs that must prepare plans for at least five years. The plans are updated every three years. ***Regulatory***

approval of cost recovery cost scrutiny – ***Depreciation method*** straight line – ***Depreciation time*** Economic useful life (EUL) is set according to requirements of accountancy law for adequate groups of fixed assets. For transformers and substations economic useful life is 30-40 years. – ***Depreciation consideration*** a component of allowed revenue. – ***Other component to adjust cost*** annual RAB adjustment
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities individual DSOs initiative – ***Transparency platforms for potential grid users*** no capacity maps exist. – ***Technical requirements*** Energy Policy of Poland until 2040 target: By 2025, 85% of connection contracts should be completed in 12 months (currently more than 50GW queuing for being accepted) – ***Unification of requirements among DSOs for grid connection*** No – ***Exemptions to file grid connection requests for EVs, HPs & RES:*** Micro installations (RES below 50 kW installed electric power) have simplified procedure, detailed in national regulations. PV with a capacity of less than 2 MW, mounted on buildings and connected to the distribution network have shorter deadlines for connection, issuing a building permit, entry in the register and issuing a concession.
Measures in case of lacking capacity
Assignment of grid capacity based on principle of equal treatment, however serious issues with a high amount of rejected connections. These are mainly due to lack of uniform and coherent application conditions and processes, which lead to uncertainty and speculative applications and blocking of grid connection rights. The TSO proposed time-limitation rules on new and existing permits to free the blocked capacities of transmission and distribution grids. The proposal is to be published, an auction system is being considered, which might include some quality elements to increase the chances of small players. As of August 2023: new rules for cable pooling (connecting two or more RES installations, such as wind and PV farms, to the same interconnection point. – ***Connection cost charging*** shallow connection charge based on individual cost; exemptions: producers vs storage vs consumers; RES vs. co-generation; EV charging infrastructure vs other consumers, variation based on voltage, location and other: first connection. – ***New policy*** a recent amendment to the Energy Law makes it possible to diverge from the shallow charges (shared on default to 50-50%) and for the connected entity to pay a large proportion ("open market terms") – ***Conditional grid connection:*** Yes, cable pooling
Process for grid connection requests
Maximum lead time for processing: The issuance of connection conditions depends on the voltage of the network to which the investor wishes to connect, and takes place within 14 days, 30 days or 3 months from the date of submission of a complete application. The procedure is often prolonged by a call for supplements until the application is regarded complete, so the procedure can take one year or longer. ***Unification of process among DSOs:*** No. ***Fully digitalized process*** Yes, TSO and DSO shall make available templates on their websites, enabling electronic submission. – ***Number of forms per request to submit:*** Utility scale: No information on the number of forms, but typically lengthy and complex procedures (especially for onshore wind) Small scale: Often different forms according to the asset to be connected (e.g. single-family building, storage device, EV charging station, etc.), usually 1 online form + attachments.
National grid conditions
Number of DSOs: 184 thereof 5 legally unbundled [threshold: 100 000 customers] – ***Ownership structure*** public, partly public and private. –***Connected customers:*** 19.1 mio. connected customers – ***Length of grid:*** 16 133km transmission grid, 990 000 km transmission and distribution network – ***Average grid age:*** approx. 30 years. – ***Curtailed demand and supply per year:*** not monitored – **Network losses**: 4.45 % (2018) – ***Policy targets for of electric vehicles and of charging stations:*** charging capacity is expected

to grow from 230 MW currently (2024) to over 342 MW by the end of 2025, and to 1,515 MW by 2030. ACER: EV stations: 7000; EV vehicles 57000. Policy targets in NECP WAM scenario: 950 000 EVs and 4700 electric busses by 2030. ***Policy targets for HAC per HH:*** 32.1% RES-H target for 2030, by 2040 all heat demand supplied by district heating and low- and zero-emission individual sources. Estimated heat pump stock (excl. air conditioners) 600 - 750 000. – ***RES-E share***: 25.8% in 2023 (of the RES share: 25.4% PV and 52.3% wind) – ***Smart meter rollout:*** currently 38% smart meter deployment (Febr 2025). target to install smart meters for 80% of the consumers by 2028, 100% roll-out by June 2031.
National particularities
The President of the ERO initiated the KET Charter (Charter for Effective Transformation of Distribution Networks in the Polish Power Sector ("KET")) in November 2022. This is an agreement between the Energy Regulatory Office and the five largest distribution system operators to create a stable regulatory environment for investments in the modernisation of transmission networks and their adaptation to the needs of distributed energy. The growing number of data centres raises the issue of speculative booking of hundreds of megawatts of connection capacity, similar to renewable energy systems.

Design features in Portugal (PT)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Biennial updating of 5-year plan, the current plan is for 2021-2025; 2026-2029 under consultation – ***Public availability***: Yes – ***Length:*** 198 pages plus annexes, 1090 pages total – ***Language***: Portuguese – ***NDP template provided?*** Yes, mandatory elements to be included are specified. – ***National NDP aggregating the DSO NDPs?*** Only one DSO NDP related to the high and medium voltage network. Investment needs of low voltage networks that occur at higher voltage levels are taken into account but not included. – ***Threshold for mandatory NDP development:*** Only one DSO at MV, HV level. – ***Harmonization within a MS:*** Only one DSO prepares DNDP, including grids at the MV and HV level. ***Key elements of NDP***: Legal framework, scope and content, Principles and criteria for planning, Development strategy, Network planning and objectives, Development of delivery points, Consumption and load forecast, Strategic environmental assessment, Risks of non-delivery of objectives, Characteristics of the network and planned improvements, Total investments, investment plan for 2021-2025. **Actionability:** Capacity maps included for HV and MV networks, planned investments, environmental assessment are included.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes – ***Main deadlines***: The proposed plan has to be submitted by 15 October (5 yrs and updates in even numbered years) to the Directorate General for Energy and Geology (DGEG) and the NRA (ERSE). – ***Geographical coverage:*** HV and MV networks on Mainland – ***NRA's role:*** It has to publish a notice in the Official Gazette, five days in advance of the public consultation (30 days) and publish materials on its website. At the end of the consultation, it has to prepare a report in 22 days, and send to DGEG and TSO and DSOs. After the submission of public consultation report, 30 days are available for DGEG, NRA and the TSO to discuss their opinion and decide on the required amendments. – ***Consultation process***: Public consultation is organised by ERSE (NRA), documentation published onsite, summary and questions included. There are specific timeframes for professional and public consultation, discussion of results with DGEG, ERSE and TSO to determine amendments, and for sending the final proposal to the Government for approval (formal approval by the Council of Ministers). – ***Alignment to TSO NDP?*** The plan is elaborated taking into account the development plans of the TSO. TSO receives the proposal of the plan. It provides opinion, and may suggest changes and amendments.

The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts Aligned with the NECP and the Roadmap for Carbon Neutrality. Consumption forecast is based on historic data with daily resolution, using a hybrid model incorporating multiple linear regression models together with neural network models. Included variables are related to macroeconomic trends, temperature effects, calendar effects, consumption inertia, energy efficiency, electric vehicle use, self-consumption. National and international forecasts and outlooks were considered also. – ***Consideration of flexibility by EVs HAC***, ***other demand***, ***storage, production curtailment:*** Regulation requires flexibility options to be considered as alternatives to conventional investments. Flexibility mechanisms are included in the plan, reducing the need for additional investments by optimizing existing resources. – ***Kind of proposed measures:*** Renovation and rehabilitation of assets, grid reinforcements, digital transformation, automation and remote control of the network, intelligent supervision and operation systems.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic Method: Energy-based, power-based (contracted and actual peak power) – ***Withdrawal charges vary by*** voltage, and time, tariffs are E- and P-based. – ***Injection charges*** are not applied. – ***Reactive energy charges*** exist for both withdrawal and injection – ***Variable network charges differentiated by:*** periods: seasonal (2), day of week (weekend), Specifics: ToU signal energy-based, and power-based, peak power variable €/kW/day for peak period, - Mandatory for HV-, MV and low V customers with contracted power >41.4 kVA with ToU structure of 4 periods, mandatory for low V customers with contracted power between 20.7 kVA and 41.4 kVA with ToU structure of 3 periods, optional for low V customers with contracted power <20.7 kVA; - Users not equipped with ToU meters are excluded; – ***Charges for storage:*** No injection charge. Intermediate consumption exempted to avoid double payments, withdrawal cost applies to final consumption. – ***Cost recovery based on*** incremental cost model. – ***Relative weighting of components***: P>E – ***Cost cascading***: from transmission to distribution, from distribution to distribution; explicit payment (separate tariff or tariff element)
Regulation
Type of regulation: Incentive regulation, (revenue-cap (TOTEX: OPEX+CAPEX) + profit/loss sharing mechanism, with 4 years period (currently 2022-2025). Quality elements included – ***Components of regulatory asset base:*** operating costs (net of additional income), controllable and non-controllable costs and investment costs. Historical costs. – ***Cost approval/scrutiny***: Formal approval by NRA – ***Yardstick benchmark method***: COLS and SFA in parametric models and DEA in non-parametric models for efficiency benchmark – ***Anticipatory investments in asset base:*** Investments included in the DNDP are taken into account. – ***Assessment of network quality:*** Incentive mechanism covering quality of service, losses reduction and services related to smart grids – ***Depreciation method***: Straight-line – ***Depreciation time/ratio***: 5-40 years, depending on asset type – ***Depreciation consideration***: RAB does not automatically adjust every year due to the revenue cap on TOTEX. However, the profit/loss sharing mechanism calculated after the end of the regulatory period considers the annual real RAB adjusted for new investments, write-offs, and depreciation – ***Time-dependencies due to base year and regulation period?*** Considered for TOTEX initial cost base and profit/loss sharing mechanism. – ***Adjustable components during regulation period*** RoR updated ex-post each year; the WACC (pre-tax) applied in the RP is indexed on the Portuguese ten-year bond benchmark and depends on its evolution with a cap and a floor. The allowed revenues from each activity are adjusted after two years based on real, audited values. Adjustments are incorporated into allowed revenues of the year with the appropriate financial update.
Timely and transparent treatment of grid connection request
Determination of grid connection potential

Methodology for grid hosting capacities: "Reception capacity" is the maximum value of apparent power that can be received at a given point, calculated with a given theoretical probability of risk, for a given time horizon and physical configuration of the network, considering the operational safety criteria and grid planning. Published values: approximations via evaluation of consumption and production values. Connection requests are evaluated on a case-by-case basis. ***Transparency platforms for potential grid users:*** Capacity values per substation are accessible online, maps and tables available via the open data portal, and are updated quarterly. – ***Unification of requirements among DSOs for grid connection***: Standardised process to be performed online. – ***Exemptions to file grid connection requests:*** No reservation of injection capacity is required in case of a) generation units below 1 MVA, b) hybridisation, c) downgrading or upgrading of the self-consumption system (by a certain amount – below 20%), and d) retrofits.
Measures in case of lacking capacity
Assignment of grid capacity based on first come first served principle, easier access by smaller and self-consumer installations, sharing connection lines is also possible – ***Connection charges:*** Deep connection charge based on individual cost (€); distance (€/m); and contracted power (€/MW). In case of producers' charges, for reinforcement, expected benefits to new connections are considered. The share of costs to be born varies by voltage level and requested power: Charge for network reinforcement varies between producers vs. consumers. – ***Conditional grid connection:*** Restricted/non-firm connection is possible, new regulation sets the conditions to be included in Network Access Agreements between owners of generation or storage facilities and the network operators.
Process for grid connection requests
Maximum lead time for processing: different according to type of installation, and the type of grid connection, clear and transparent timelines are set. In case of the general procedures, applications submitted to DGEG electronic platform shall be replied in 5 days in case of no restriction, and the amount of reserve capacity security is notified. Injection capacity reserve title is issued within 10 days if the opinion of the grid operator is positive. In case of other applications, interested parties can request an estimate of the cost of grid connection from the respective grid operator within 30 days. – ***Unification of process among DSOs based on*** digital, electronic platform operated by DGEG. – ***Fully digitalized process:*** Simple process for self-consumers, with the help of E-REDES, request submitted through the electronic platform, process can be monitored online – ***Number of forms per request*** depends on the type and size of plants – ***Default action in case of surpassing lead time***: Automatic approval.
National grid conditions
Number of DSOs: 13, of which only one with more than 100 k customers – ***Ownership structure:*** Private ownership – ***Connected customers/features:*** 6.4 M, 234.669 km network and 46 TWh distributed energy (2023) in Mainland, 273 410 customers and 9 452 km grid (2023) in Acores and Madera. No exact information on curtailed demand or supply, only planned outages. However, they occur more and more frequently, and can reach more GWs. Distribution loss (2023) 7.8%. – ***Policy targets for electric vehicles and charging stations***: Presently, the No. of charging points are 8139 AC, 3035 DC, and there were around 130000 fully electric cars in Nov 2024. The national goal is to have 100% electric vehicles by 2050 with an intermediate target of 36% by 2035. The market share of newly bought plug in and BEV is 14,7%, only BEV, 10,6% – ***Policy targets for HAC***: Share in total heating energy consumption: 38% in 2025, 41% in 2030, according to NECP projections, no specific goal. – ***RES-E share***: 63% in 2023 (of which 14.5% PV and 38.3% wind) – ***Smart meter rollout:*** 99% smart meter deployment, goal: 100% by 2025.
National particularities
Advanced digitalization of processes, user friendly, on-line registration and licensing procedures. High penetration of smart meters, good accessibility of data via online platform. Broad stakeholder involvement in regulatory process. Encouraging analysis of available digital data, e.g. by students.

Design features in Romania (RO)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Biennial for 10 years plan; annual investment plan; 5-years investment plan in the reference year of a regulatory period –***Public availability:*** Yes – ***Length:*** ~100 pages/DSO – ***Language:*** Romanian – ***NDP template provided?*** No – ***National NDP aggregating the DSO NDPs:*** No harmonised document – ***NDP template provided?*** No – ***Threshold for mandatory NDP development***: No threshold – ***Key elements of NDP***: Investment plan with schedule, expenses, changes from previous plans, status of previous projects.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, ***Main deadlines:*** Submission to NRA: by July 1 of the year preceding the 10-year period (with all supporting documents, and the result of the public consultation) – ***Geographical coverage:*** DSO territory (8 regional territories in the country) – **NRA's role:** The NRA approves the plans individually, no other approval is needed. – ***Consultation process***: Public. Involved stakeholders: county councils, other local and central public authorities, producer associations, consumer associations, etc. (open list). The summary of the observations/proposals received during the public consultation period, including the DSOs resolution regarding the acceptance or reasons for non-acceptance of the proposals received, must be submitted to the NRA together with the NDNP, ***Alignment to TSO NDP?*** TSO-DSO alignment is not required by the Law, but they are involved in the public consultation, ***Available data basis from TSO?*** Yes
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts: Varies among DSOs. There is no scenario analysis in many cases, other refers the NECP WEM and WAM scenarios. Rely on own analysis of consumption patterns consumers activity by voltage levels; number of places of consumption, prosumers. ***Consideration of flexibility by EVs, HAC, other demand***, ***storage***, ***production curtailment:*** No. – ***Kind of proposed measures:*** Grid reinforcements, Digitalisation (intelligent metering and control systems), Dynamic Line Rating
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: Energy-based – ***Withdrawal charges vary by*** voltage. – ***Injection charges vary by*** none. – ***Variable network charges differentiated by*** *none.* – ***Charges for storage:*** injection: E-based (exemptions apply); withdrawal: E-based; gross withdrawal – ***Responsible party of tariff methodology***: NRA, yearly update – ***Cost recovery based on:*** average cost – ***Relative weighting of components***: E>P – ***Cost recovery based on*** average cost] – ***Relative weighting of components***: E>P – ***Cost cascading:*** from transmission to distribution, from distribution to distribution; explicit payment (separate tariff or tariff element)
Regulation
Type of regulation: Incentive regulation (price cap) with 5 years period (currently 2024-2028), yardstick benchmark and efficiency factor – ***Components of regulatory asset base*** Fixed assets, except contributions from third parties.– ***Cost approval/scrutiny***: Formal approval by NRA – ***Anticipatory investments in asset base:*** No. – ***Assessment of network quality:*** number and duration of interruptions – ***Depreciation method***: Straight line – ***Depreciation time/ ratio***: Depends on asset type – ***Depreciation consideration***: Part of regulated revenue. Depreciation is included directly and 100% in revenue – ***Time-dependencies due to base year and regulation period?*** Base year for next period: 2023 – ***Adjustable components during regulation period:*** The NRA calculates annually revenue corrections due to inflation, investment, non-controllable (pass-through) operating and maintenance costs, changes in energy volumes and losses (quantity and price of

losses); WACC can be updated during the RP; if the accomplished value of annual investments is less than 80% of the predicted value taken into consideration, an annual revenue adjustment is made. These annual adjustments are considered at the end of the RP for the final corrections. Outlook: NRA approved new methodologies starting from the fourth RP to harmonise the provisions of the four methodologies.
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Transparency platforms for potential grid users: No interactive map, available capacities are reported only for the transmission system – ***Unification of requirements among DSOs for grid connection:*** No – ***Exemptions to file grid connection requests for:*** None
Measures in case of lacking capacity
Assignment of grid capacity based on First-come-first-serve principle. From 2026: auction allocation of electricity network capacity for connection of electricity production sites, with the installed power of electricity production facilities greater than or equal to 5 MW. – ***Connection charges:*** Shallow and deep connection charges based on Individual actual cost - lump sum; exemptions: Producers vs. consumers, variation based on voltage.– ***Conditional grid connection:*** From June 2025, new Romanian grid connection permits will include "Operational Limitations" allowing the grid operator to curtail power output, even to zero, during congestion to ensure grid stability (ANRE Order 20/2025).
Process for grid connection requests
Maximum lead time for processing: deadlines for every step, e.g.: 10 working days for evaluation of the submitted documentation; +30 calendar days for establishing the connection solution and issuing the ATR (technical connection permit); + 90 c days for design and execution of the connection. – ***Unification of process among DSOs:*** Standardization by NRA – ***Fully digitalized process:*** Fully digital for some DSOs (not all) – ***Number of forms per request to submit***: DSO-specific. Digital, user-friendly platform with many information at most DSOs, less developed solutions at others.
National grid conditions
Number of DSOs: 8 legally unbundled and 33 smaller. – ***Ownership structure:*** Mainly private investors, indirect public ownership – ***Connected customers:*** 9.4 mio. connected customers – ***Length of grid:*** ~90,000km – **Network losses**: 9.1% (2021) – ***Policy targets for of electric vehicles and of charging stations:*** BEV: 2023: 38 thousand. target (WAM): 0.68m by 2030, 4.4 million by 2050. Charging station: current: 1972; targets for 2030: >50kW highway: 2896 >50kWh urban: 13200 – ***Policy targets for HAC per HH:*** 25% of HH by 2050 – ***RES-E share:*** 47.7% in 2023 (of the RES share: 8.7% PV and 27.4% wind) – ***Smart meter rollout:*** 23.3% smart meter deployment (no target in NECP or NES)
National particularities
Romania's distribution network is gradually adapting to decarbonization, with Distribution Network Development Plans (DNDPs) in place, but incentive tariffs are not introduced yet. Slow handling of connection requests and outdated infrastructure remain key challenges.

Design features in Slovakia (SK)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: annually for a period of five years – ***Public availability:*** Yes – ***Length:*** 3 DNDP: 19/32/53 pages – ***Language:*** Slovakian – ***NDP template provided?*** No, but there is a list of required information in 230/2023 Coll. – ***National NDP aggregating the DSO NDPs?*** No – ***Threshold for mandatory NDP development***: 100k connections for issuing own NDP – ***Key elements of NDP***: No capacity maps exist (or covered), DNDPs must contain several details regarding investment plans and costs, but these are hidden in the public versions of DNDPs.
Procedural steps, data collection and governance of NDPs

Obliged by national legislation? Yes (251/2012 Coll.), ***Main deadlines***: November 30 (annually) – ***Geographical coverage***: The DSO submits the plan for its own area – ***NRA's role*****:** NRA and the ministry approves the DNDP. – ***Consultation process***: No public consultation between DSO and NRA – ***Alignment to TSO NDP?*** The DNDP is based on the consumption and other data contained in the TYNDP – ***Available data basis from TSO:*** No
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts DNDPs use load and production data from the TSO's TYNDP as input. – ***Consideration of flexibility by EVs, HAC, other demand***, ***storage***, ***production curtailment:*** No- ***Kind of proposed measures:*** Grid reinforcements; support for the connection and integration of devices producing electricity from renewable energy sources, the development of electricity storage devices and the electrification of transport is ensured not only by the development of the distribution system but also by the renovation of the distribution system, which often means replacement with more energy-efficient devices
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: energy-based, power-based (contracted or rated power) – ***Withdrawal charges vary by*** voltage level – ***Injection charges:*** power-based, ***vary by*** voltage; ***exemption:*** no tariff for ancillary service providers – ***Variable network charges differentiated by*** day of week (weekend), peak/off-peak; specifics: off-peak has to be offered 8 or 20 hours. Optional for all users with access; users who do not meet specifications of Slovak NRA Decree 18/2017 are excluded. ToU applied for 10% - 25% of D-connected users – ***Responsible party of tariff methodology***: NRA; 5 years (but in practice typically 1 year) – ***Charges for storage:*** Injection: P-based (some exemptions apply); withdrawal: E- and P-based; gross withdrawal. (D-connected storages providing ancillary services do not pay any access to the grid charge; storages for commercial purpose pay charge for access for injection or withdrawal based on the higher connection capacity; hydroelectric power plants with capacity <1MW are fully exempted) – ***Cost recovery based on*** average cost – ***Cost recovery through injection tariff***: Yes, approximately 1% – ***Relative weighting of components***: P>E – ***Cost cascading:*** from transmission to distribution, from distribution to distribution; explicit payment (separate tariff or tariff element
Regulation
Type of regulation: incentive-based regulation and price cap with 5 years period (currently 2023-2027); yardstick benchmark and quality element. Further elements: allowed costs, allowed depreciation, RAB, WACC [Cost-based /incentive-based] –***Components of regulatory asset base:*** fixed assets, no working capital – ***Regulatory asset value:*** Expertly appraised value of assets used for regulated activities as at 1 Jan 2011 – ***Yardstick benchmark method:*** efficiency factor applied to controllable OPEX set to 2% – ***Assessment of network quality***: URSO has also regulated the quality of services, which focuses primarily on consumer protection – ***Depreciation method***: regulatory depreciation (technical life cycle of assets) – ***Depreciation time/ ratio***: ratio between 1.25% and 20% – ***Depreciation consideration***: a component of target revenue –***Treatment of capital and operational expenditures:*** No RAB adjustment during RP; In the event of a significant change in the economic parameters based on which URSO approved or set the price, the regulated entity may request an amendment in the price decision. URSO may also initiate a change in the price decision on its own initiative.
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: National capacity mapping – ***Transparency platforms for potential grid users:*** Capacity map exists, available capacities visible at DSO level. (Technical Conditions are also available.) – ***Unification of requirements***

among DSOs for grid connection: Not unified but requirements are similar among DSOs – ***Exemptions to file grid connection requests:*** no exemptions
Measures in case of lacking capacity
Assignment of grid capacity based on First-come-first-serve principle – ***Connection charges:*** Shallow connection charge based on Contracted power (€/kW); exemptions: Producers vs consumers; Different unit charges for households vs. non-households, variation based on voltage – ***Conditional grid connection:*** Not yet available, expected to change from 1st of July 2025 or 1st of January 2026.
Process for grid connection requests
Maximum lead time for processing: Within 30 days of receiving a request, the DSO send a draft Agreement on the connection of the system user's equipment to the distribution system – ***Unification of process among DSOs:*** Yes, however, individual DSOs manage specific aspects for distribution grid connections, leading to minor variations. – ***Number of forms per request to submit***: Digital platforms are available (in 2 out of 3 DSOs) and useful information videos helps the process.
National grid conditions
Number of DSOs: 3 legally unbundled with more than 100 k customers –***Ownership structure:*** Public and private – ***Connected customers:*** 2.7 Mio. connected customers – ***Length of grid:*** low V lines length (sum of 3 DSOs): 88447 km – ***Policy targets for electric vehicles and charging stations:*** In 2023: 10 000; 1808 charging stations in 740 locations – ***RES-E share:*** 24.2% in 2023 (of the RES share: 9.6% PV and 0.1% wind) – ***Smart meter rollout:*** 94.5% smart meter deployment
National particularities
In the case of two of the three DSOs, progress is evident in the field of digitization and general operation. The differences between DSOs can be traced back to ownership and management. Due to the revised market design directive, several changes in regulation are expected in the coming year.

Design features in Slovenia (SI)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: NDP is updated every two years (biennially) with a focus on at least a 10-year planning period. – ***Public availability:*** Yes – ***Length:*** 256 pages – ***Language:*** Slovenian, with certain summaries available in English. – ***National NDP aggregating the DSO NDPs?*** Yes, individual DSO plans are aggregated into a national-level NDP, ensuring consistency. – ***Threshold for mandatory NDP development***: No exact information on any threshold, but according to the European Directive DSOs with fewer than 100,000 connections may be exempt from mandatory NDP development. – ***Key elements of NDP***: No capacity maps exist. The Slovenian NDP includes: Grid congestion analysis; Investment plans for infrastructure expansion; Development of renewable energy sources; Digitalization and smart grid initiatives; Plans for increasing system flexibility and storage capacity. The Electricity Supply Act (ZOEE) states the following must be included as key elements: Focus on medium- and long-term flexibility services; Planned investments for the next 10 years in main distribution infrastructure; Key priorities: Connecting new generation capacities, new customers, and EV charging stations; Use of demand response, energy efficiency, and energy storage as alternatives to network expansion; Assessment of available capacity for distributed generation and energy storage; Priority measures: Enhancing energy efficiency of existing infrastructure through load management, demand adjustments, and system services to avoid costly network expansions.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes, Slovenian national legislation mandates the development of NDPs as specified in the Energy Act (EZ-1-UPB2) and related EU directives.

– ***Geographical coverage***: National coverage, with individual DSOs contributing to the overall NDP. – ***Responsibility of NRA:*** The NRA is responsible for the formal approval of the development plan for DSO. It reviews the submitted plan (including consultation results), may request amendments, and must decide on approval within three months. – ***General stakeholder engagement:*** Consultation executed. The distribution operator must consult with all relevant system users and the system operator about the development plan for the distribution system. The distribution operator publishes the results of the consultation process along with the development plan for the distribution system and submits both the consultation results and the development plan to the agency. – ***Alignment to TSO:*** The distribution operator shall also consult with the transmission system operator before public publication of the development plan.
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Scenario building and forecasting: The NDP bases its scenarios and forecasts on: NECP (National Energy and Climate Plan). National strategies such as the Energy Act and Renewable Energy targets. Connection requests, historical trends, and REPowerEU strategy. – ***Consideration of flexibility by EVs***, ***HAC***, ***other demand***, ***storage***, ***production curtailment:*** EVs: Yes. EV integration is a core part of the NDP; HAC: Yes; Heat pumps and electrification of heating are included in the forecasts. Other demand: Yes; Includes integration of distributed energy resources and demand response systems; Storage: Yes. Focus on battery storage systems and flexibility from pumped hydro storage. – ***Kind of proposed measures:*** Approaches mentioned in the NDP: Grid reinforcements, Flexibility services (Introduction of grid-scale storage systems), Use of On-Load Tap Changers (OLTCs) for voltage regulation. Improved accessibility for EV charging stations and heat pumps; Strategies for congestion management (e.g. increase amount of flexible power plants in redispatch): Implementation of demand response programs to manage peaks, Dynamic load shifting through smart grid technologies, Method for capacity determination: Dynamic Line Rating (DLR): To optimize line capacity based on real-time environmental conditions, Voltage limits and contractual capacity mechanisms.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: Energy-based, power-based. Variation by voltage and time-of-use. – ***Charges for injection:*** Never applied. – ***Variable network charges:*** A new tariff system took effect on October 1, 2024, applying only to network charges. Tariff period differentiation is made by day of week (weekend/holidays), peak/off-peak, and there is a 2-tier structure (energy and capacity charges). According to the new methodology, differentiation is based on voltage levels: HV (VL4: high voltage transmission – consumption at 110, 220, 400 kV); VL4D: HV (high voltage distribution – consumption at 110 kV); VL3: MV at substation busbar HV/MV; VL2: MV (middle voltage: consumption at 35, 20, 10 kV); VL1: LV at transformer station (TS) busbar MV/LV; VL0: LV (low voltage: consumption at 1, 0.4 kV). The time signal (ToU) is per capacity and energy charge, no differentiation among user group. – ***Responsible party of tariff methodology***: NRA, yearly price setting. – ***Treatment of storage facilities:*** Storage facilities connected to the distribution network in Slovenia are generally subject to network tariff charges. However, to promote the construction of electricity storage facilities, a new potential instrument was mentioned in the latest NECP: preparing a legal basis for a 10-year moratorium on network charges for all electricity storage facilities. – ***Cost recovery:*** Cost model: average cost; Cost recovery through withdrawal charges (weight of components): E > P; Cost cascading: from transmission to distribution, from distribution to distribution; explicit payment (separate tariff or tariff element).
Regulation
Type of regulation: Incentive regulation - revenue cap – ***Regulation period***: 1 year; - ***Yardstick benchmark***: Yes - **Quality element**: Yes; - ***Further elements***: Controllable OPEX (efficiency score, general productivity), uncontrollable OPEX, CAPEX (depreciation, regulated return on assets), losses, consumption, incentives, efficiency dependent WACC.

– ***Regulatory approval of DSO investment requests:*** Components of regulatory asset base: Book values of tangible and intangible assets after RAB adjustment, ex ante investments according to development plan, no working capital, no assets under construction. Regulatory asset value: Book value for existing assets, investment value according to development plan for new assets; – ***Regulatory approval of cost recovery:*** Efficiency value taken from national benchmark. Achieved quality of supply level are determined according to the achieved level of supply continuity from the reference level. ***Depreciation method***: straight line. For existing assets, the actual rate of depreciation depends on the asset type; For planned new investments in energy infrastructure 3.33% and for other assets 8.33% - ***Depreciation consideration***: pass-through. – ***Treatment of capital and operational expenditures:*** Consideration of investment types: Both CAPEX and OPEX are considered.
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Comparable information tool. – ***Transparency platforms for potential grid users:*** No capacity maps exist, direct customer service for PV is provided by the DSO.
Measures in case of lacking capacity
Assignment of grid capacity**:* Type: Capacity allocation follows a "First-come-first-serve" basis. Small-scale producers and critical loads may receive prioritization. Is there a formal process? Yes, DSOs adhere to this principle while ensuring fairness and grid efficiency. – ***Connection cost charging fees: Shallow connection charge based on Individual actual cost (€) contracted power (€/MW); exemptions: Some storage facilities vs., variation based on voltage.
Process for grid connection requests
Maximum lead time for processing: Yes, the regulatory framework sets a maximum processing time of 90 days. – ***Default action in case of surpassing lead time***: If the lead time is exceeded, requests are escalated for regulatory intervention. – ***Unification of process among DSOs:*** Yes. Processes are standardized across DSOs and use digital platforms for submission and approval. ***GAP Requirements Fulfilled?*** Yes, digitalized and streamlined processes align with EU requirements. – ***Number of forms per request to submit:*** Not comparable, but the document emphasizes minimizing complexity by centralizing approvals with the DSO or NRA.
National grid conditions
Number of DSOs: There are five DSOs in Slovenia that operate on behalf of ELES under a leasing contract for the distribution network: – ***Ownership structure:*** Regarding their ownership structure, these DSOs are structured as public limited companies (d.d.). Important: As of October 2023, the merger process of the company SODO, d. o. o. (Ltd.), Electricity Distribution Operator (acquired company) with the company ELES, d. o. o. (Ltd.), Electricity Transmission System Operator (acquiring company) has been completed. – ***Grid dimension:*** Approximately 933.000 consumers. – ***Average grid length***: 65,252 km, including LV, MV, and HV networks. 110 kV voltage lines: 908 km, 1-35 kV voltage lines: 17,798 km and 0.4 kV voltage lines: 46,546 km. – ***E-mobility development:*** 3% of overall vehicles in 2024 are electric. – ***RES-E share***: 41.9% in 2023 (of the RES share: 16.7% PV and 0.1% wind) – ***Smart meter rollout:*** 58,2% of grid connection points had smart meters installed in 2018 (it was 50% in 2016), with a policy target of around 80% by 2030.
National particularities
The distribution network has not been designed in the past to host the significantly increased capacities of RES and electrification of heating and transport, so it represents the bottleneck for such a new load on the level of numerous nodes. Consequently, ca. 25% of applications for individual self-consumptions have been rejected in 2024 due to network limitations. On the other hand, many nodes in distribution network operate close to their thermal limits or are even temporarily overloaded (some even during the summer). Therefore, the appropriate

network price signals (also local dynamic) are needed in order to incentivize the efficient use of networks: these have been accomplished with new tariff methodology (in use from 1. 10. 2024)

Design features in Spain (ES)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: Article 32 of EU 2019/944 has not yet been transposed in regulation in Spain. They have a different, national planning system: investment plans have to be submitted annually, with a 3-year planning period (one year mandatory and 2 more years indicative) for large DSOs, and less frequent (every 3 years) for small DSOs. ***Public availability:*** Not mandatory to publish – ***Length:*** varies by DSO and region, 15-20 pages – ***Language:*** Spanish – ***NDP template provided?*** Legislation includes minimum required content. – ***National NDP aggregating the DSO NDPs?*** NRA aggregates and provides an analysis of the plans. – ***Threshold for mandatory NDP development***: Different requirements for large and small DSOs – ***Key elements of NDP***: Minimum content of investment plans: a) data of the investment projects, b) their main technical characteristics, c) their budget, and d) the schedule of implementation.
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? DNDP no, investment plans yes. – ***Main deadlines:*** Detailed in the regulation, submission: 31 May, each year. – ***Geographical coverage***: Regional – ***NRA's role:*** Collection of plans, providing feedback, aggregation and analysis of plans. – ***Consultation process***: No consultation and stakeholders are not involved. ***Alignment to TSO NDP?*** There is no formal communication between TSO and DSOs in the planning process, only informal consultation. – ***Available data basis from TSO:*** Information published in the TNDP of the TSO can be used.
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts based on NECP supplemented with own, self-developed forecasting tools – ***Consideration of flexibility by EVs, HAC, other demand***, ***storage***, ***production curtailment:*** Not yet, it is planned, regulatory sandboxes are launched. – ***Kind of proposed measures:*** Grid reinforcements and digitalization investments, because other type of measure (e.g. flexibility services) are not recognized in the tariff regulation.
Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: Energy-based, power-based (contracted and actual power) – ***Withdrawal charges vary by*** voltage and time, differentiated by consumer type. Time of use differentiation (both E and P based). In case of non-households: 6 periods for E- and P-based ToU, in case of households: 2 periods for P-based ToU and 3 periods for E-based ToU. – ***Injection charges:*** Never applied. – ***Reactive energy charge*** for withdrawal. – ***Variable network charges differentiated by*** periods: seasonal (4), day of week (weekend), and within day ToU (see above). The basis for setting the periods is network capacity use. – ***Charges for storage:*** None of withdrawal or injection charge, storage is not subject to network tariffs due to its beneficial impact on the system and security of supply – ***Responsible party for setting tariff methodology***: NRA, yearly – ***Cost recovery based on:*** average cost – ***Relative weighting of components***: P>E – ***Cost cascading:*** from transmission to distribution, from distribution to distribution; explicit payment (separate tariff element).
Regulation
Type of regulation: Incentive regulation, 6-year regulatory periods (currently 2020-2025). Revenue cap combined with reference network model. Remuneration for investment, OPEX,

extended lifetime of assets, cost of other regulated tasks (metering, invoicing, grid planning, etc.) which are set according to reverence values, calculated with the number of clients (providing incentives for efficient operation) and quality incentives. – ***Components of regulatory asset base:*** RAB is updated every year, by adding new investments and subtracting depreciation. Assets under construction and working capital, subsidies and assets built or financed by third parties are not included. Assets reaching the end of their regulatory lifetime are taken out of the RAB. – ***Cost approval/scrutiny***: Formal approval by NRA – ***Yardstick benchmark method:*** reference investment values used, which are outdated and 10 years old – ***Anticipatory investments in asset base:*** No, and an annual cap is applied on the total D level investments. – ***Assessment of network quality:*** Incentive payment to reduce grid losses and to improve quality of supply – ***Depreciation method***: Straight line method. Regulatory asset lifetime: 40 and 12 for network assets and control centres, respectively. ***Depreciation time/ ratio***: generally 2.5%. – ***Depreciation consideration***: 100% of depreciation is integrated into the revenues. – ***Time-dependence due to base year and regulation period?*** Regulatory parameters are not updated by price indexes within the regulation period. – ***Adjustable components during regulation period:*** RAB is updated every year, by adding new investments and subtracting depreciation.
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Indicative values included in capacity maps, evaluated individually in case of application. ***Transparency platforms for potential grid users:*** Yes, information provided on online platform on accessible capacity – ***Unification of requirements among DSOs for grid connection:*** Yes, with a single point of contact – ***Exemptions to file grid connection requests:*** Self-consumers without feeding in surplus to the grid below 15 kW power, same with surpluses if the production facility is located on urbanized land that has the facilities and services required by urban planning legislation, and vulnerable consumers who meet requirements set in regulation.
Measures in case of lacking capacity
Assignment of grid capacity based on first come first served principle, decided according to the date the guarantee (grid bond) is deposited. In case of lack of capacity, hybridisation of projects can provide an opportunity to connect to the grid. – ***Connection charges:*** Deep connection charge based on lump sum (€); contracted power (€/kW). There are no exemptions, but there is variation based on voltage. Certain refunds might apply according to cost sharing methods between network users. – ***Conditional grid connection:*** No conditional/flexible grid connection is available yet, the regulation is under process.
Process for grid connection requests
Maximum lead time for processing: Connection point to the distribution network at a voltage lower than 1 kV: up to 15 kW and no new network extension installations are required: five days, in all other cases: 15 days. connection point to the distribution network between 1 kV and 36 kV: 30 days, above 36 kV: 40 days, above: 60 days. 60 days (20 days for first reply and asking for corrections in the request, 20 days for correcting, 20 days for acceptance/rejection). – ***Default action in case of surpassing lead time***: default rejection in case of surpassing by the applicant the 20 days for correction, default acceptance in case of surpassing the second 20 days of acceptance/rejection in case of correct application, however, in practice no automatic connection is performed in case of delay, DSO pays penalties – ***Unification of process among DSOs:*** Yes, based on electronic platforms of DSOs, with one point of contact – ***Fully digitalized process:*** Yes – ***Number of forms per request to submit:*** Single application form that covers both the access permit and the connection permit.
National grid conditions
Number of DSOs: 328 small and 5 large DSOs with more than 100 k customers – ***Ownership structure:*** Private: 5 large DSO are part of integrated utilities – ***Connected customers/features:*** around 30 million connected customers, 797,682 km (2022) – ***Policy***

targets for electric vehicles and charging stations: 5.5 million set in NECP for 2030. At present: 30385 Charging Points, 933 Capacity (kW), No. of electric vehicles 466,178. – ***Policy targets for HAC per HH***: No specific target found. At present, the market share of heat pumps in space heating 2024 39.1% (newly bought), the total stock is 1.4 million in space heating and 103 thousand in water heating. – ***RES-E share:*** 56.9% in 2023 (of the RES share: 32.1% PV and 44.1% wind) – ***Smart meter rollout:*** 99% smart meter deployment.
National particularities
Spain has achieved 99% smart meter penetration, which is considered a success in national policy discussions. The country also has well-designed and widely used Time-of-Use (ToU) tariffs, though their documented impact remains limited. However, tariff regulation presents challenges, including a legislative cap on annual investments and the use of outdated standard equipment costs for tariff setting. These limitations hinder forward-looking investments and fail to account for the rising electricity demand driven by electrification, which will ultimately lead to higher payments for network services.

Design features in Sweden (SE)

Appropriate network development planning (NDP)
Regulatory regimes and practices for the design and implementation of NDPs
Update frequency: every two years – ***Public availability:*** *Yes,* NDPs are published for stakeholder consultation. – ***Length:*** Varies among DSOs; for some, up to ~92 pages – ***Language:*** Swedish – ***NDP template provided?*** Yes – ***Threshold for mandatory NDP development***: DSOs with fewer than 100,000 connections may be exempt from mandatory NDP development, implementing the option provided in Article 32(5) of the Electricity Directive – ***Key elements of NDP***: Showing regions with high energy transmission demands, A ten-year investment plan focuses on projects categorized into phases such as "under consideration," "preparatory," and "construction." – ***NDP as Legal basis for investments*** No
Procedural steps, data collection and governance of NDPs
Obliged by national legislation? Yes. DSOs must submit NDPs to the regulatory authority, ***Main deadlines***: updated every 2 years – ***Geographical coverage***: National coverage, with each DSO's plan focused on its licensed area. – **NRA's Role: It** receives and monitors these NDPs to ensure compliance with legislation. It does not formally "approve" each plan in a binding sense, nor does it merge them into one national plan. However, it can request clarifications or additional data if a DSO's plan is unclear or deemed noncompliant. – ***Consultation process***: DSOs conduct stakeholder reviews, gather feedback, and submit final NDPs to regulator. ***Alignment to TSO NDP?*** DSOs coordinate with TSO for scenario alignment (shared forecasts, analysis), ***Available data basis from TSO*** The DSO is responsible for collecting metering data for each customer within the grid area, including data validation and delivery of metered values to the TSO. The DSOs are obliged to report hourly metering values to the suppliers if the customers' meters are read on an hourly basis.
The integration of renewables, the development of charging stations and the electrification of heating and cooling of buildings
Basis for load and production forecasts *Scenarios are typically based on multiple elements: connection requests, policy targets, plus direct consultations with local stakeholders* – ***Consideration of flexibility by EVs***, ***HAC*** Yes, however, the level of detail differs greatly across DSOs. No standardized procedure; "different initiatives" exist for forecasting. Dialogue with stakeholders and integrating relevant EV or heat pump data, ***Other demand*** data centres, ***Storage*** commercial batteries, ***Production curtailment*** Not separately specified – ***Kind of proposed measures:*** - Focus on upgrading and expanding transmission capacity, including new 400 kV power lines and replacing aging infrastructure

Appropriate network tariff regimes and regulatory incentives
Tariff structure
Basic method: *A combination of energy and power* ***withdrawal charges varying by*** voltage level ***and exemptions for*** no ***injection*** **charges** DSOs commonly have a hybrid approach: a fixed or subscription fee, an energy-based component, and increasingly a power-based (capacity) component. ***and exemptions for*** reduced or no tariff today for injection ***variable network charges differentiated by*** time – ***Responsible party of tariff methodology***: DSOs set/adjust tariffs individually, without ex-ante approval by NRA. The NRA is responsible to survey the DSOs tariffs. - ***charges for storage*** – No special tariff in general according to regulation. – ***Cost recovery based on*** average cost – ***Relative weighting of components*** E>P
Regulation
Type of regulation: Revenue cap (ex-ante) ***regulation*** with 4 years period – ***Components of regulatory asset base:*** Fixed assets divided into lines, cables, buildings, shunt reactors, transformers, switchgear, stations, cable cabinet, control equipment, meters, and IT-system (not assets under construction);- Replacement values (after age-adjustment SEK ~226 billion in 2021) – ***Anticipatory investments in asset base*** No – ***Yardstick benchmark method***: Straight line – ***Consideration of investment types*** TOTEX – ***Adjustable components during regulation period:*** Grid components without active customers are deducted from the capital base thereby reducing DSO revenue
Timely and transparent treatment of grid connection request
Determination of grid connection potential
Methodology for grid hosting capacities: Individual Assessment – ***Transparency platforms for potential grid users:*** easy information on PV connection process. Offers only a map of the national grid that displays existing infrastructure, including power lines and substations, but not an interactive one – ***Unification of requirements among DSOs for grid connection:*** TSO sets broad guidelines; each DSO tailors them
Measures in case of lacking capacity
Assignment of grid capacity based on principle of priority – ***connection charges with*** Deep – ***Conditional grid connection*** Not standard
Process for grid connection requests
Maximum lead time for processing: Reasonable time, but no longer than two years if there are not special reasons approx. – ***Unification of process among DSOs*** No. Processes vary among DSOs ***based on*** overarching national regulations – ***Fully digitalized process*** Yes – ***Number of forms per request to submit***: General Forms and Approvals: Inquiry: Initial application for grid connection; Agreement: Principle decision agreement; Application: Line concession application (if needed); Agreement: Connection agreement after approval.
National grid conditions
Number of DSOs: 150/170 – ***Ownership structure:*** State, municipality, private, and foreign ownership – ***Length of grid:*** ~568,000 km – ***Average grid age:*** In 2018, the oldest parts of the transmission grid's 400 kV power lines was of 70 years old and parts of the 220 kV grid are even older. – **Network losses**: 5 TWh network losses in 2021 – ***# of electric vehicles:*** - Total EV in passenger car segment is around 60.6% in 2023; - total fleet of plug-in vehicles surpassing 600,000 units by the first quarter 2024 – ***charging stations***: - 32413 AC charging points & 4753 DC charging points (in 2023); - 126% increase in charging points compared to the same period in 2023. – ***HAC per HH***: - residential boilers 2 TWh in 2016; - fossil fuel free1 by 2030, and by 2045, the sector should be a carbon sink; - no fossil fuels in district heating production by 2030; - phase out all direct use of fossil fuels in; heating buildings by 2030; - in 2020 approximately 50 000 heat pumps were installed in Sweden; -The total energy consumption for heating and hot water in dwellings and non-residential buildings in 2020 amounted to 73,8 TWh.; -In 2020 district heating accounted for 43,1 TWh which corresponds to approximately 58 % of the total energy consumption in dwellings and non-residential buildings. Almost 53 % of the district heating was used in apartment buildings while 35 % was used in non-residential buildings. In single-family houses, district heating

accounted for roughly 12 %.; - In 2020, there were roughly two million single-family houses in Sweden. The number of dwellings with any kind of heat pump amounted to approximately 1 215 000. 95 % of the heat pumps are found in single-family houses, and the total number of heat pumps installed in 2020 amounted to 1 460 000. – ***RES-E share***: 87.5% in 2023 (of the RES share: 2.6% PV and 31.6% wind) – ***Smart meter rollout:*** 100% smart meter deployment
National particularities
In the Swedish legislation of today there are exemptions regarding charges for injection. Microprosumers (<63 A / 43,5 kW) are excluded from charges. Small scale generation (< 1 500 kW) only pay for metering, registration, calculation/settlement and reporting, i.e. a reduced grid fee. Tariff design includes capacity charges that are location-based and differ for consumption and generation in the North-South gradient to reflect the higher demand in the South. DSOs have wide latitude in tariff design (ex-post regulation rather than ex-ante), and the revenue-cap model lacks explicit treatment for “anticipatory” investments. 100% smart meter coverage facilitates time-differentiated tariffs, but storage remains treated as regular load plus generation. On the system side, the grid extends over 568,000 km, with some 400 kV lines. Electrification is surging: over 600,000 plug-in vehicles by 2024, a 126% jump in charging points (now ~37k total), and 1.46 million heat pumps installed (most in single-family homes). Already at 87.5% renewables in electricity (wind ~31.6%, PV ~2.6%), Sweden aims to phase out fossil fuels in heating by 2030, leveraging widespread district heating (~58% of building heat).

8.3. Appendix 3: Methodology and Interview composition

Development of the member state factsheets

We gather data about the practices that are currently in place in all 27-EU MS. The data collection follows a matrix structure. The overview of the EU-27 practices and the design terminology serves to create insights from a MS (column logic) and a design perspective (row logic). **Table 11** illustrates the structure of data collection and examination for the EU-27 practices.

Table 11: Schematic illustration of the structure of data collection and examination for the EU-27 practices

2. Topic area: Appropriate network tariff regimes and regulatory incentives						
2.1. Subtopic Network tariff regimes						
Design category	**Austria**	**Belgium**	**Bulgaria**	**Croatia**	**...**	
Withdrawal charges	...	...	...	...	...	**Row logic: Findings per topic (Chapters 3-5)**
Injection charges	...	...	...	...	...	
Variable network charges	...	...	...	...	...	
Exemptions	...	...	...	...	...	
...	...	...	...	...	...	

Column logic: MS fact sheets (Appendix)

The purpose of assembling this data base is to develop factsheets for all MS that summarize the information in a concise manner. Factsheet templates covering the three topic areas and national grid conditions are used to collect the data. Topic areas, subtopics, design categories (e.g. variable network charges), and examples of their design features (e.g. time-of-use tariffs) constitute the template's structure.

The desk research consists of an initial, overarching collection of secondary data from multi-country studies and an MS-specific collection by MS experts. The process also includes monitoring recent policy documents. Following the first round of research, the gathered data is combined into a MS factsheet. In terms of methodology, the information collection is pre-structured and follows a matrix logic (see **Table 11**). This represents the methodological basis for the first round of information collection and leads to a common template for MS factsheets across the EU 27.

After the initial data collection process, the template is adjusted for streamlining and ensuring consistency. In particular, overlaps between the design categories are removed and answer choices are included in the form of building blocks (e.g. [Yes/No]) or lists of exemplary answers. A systematic foundation for the information required in each MS is thus provided by the data from the multi-country sources. From this, the topic leads provide structure to designated MS experts that conduct the further desk research but receive guidance on what to search for in particular.

The MS experts then take over to complete the MS fact sheets through focused literature review per MS. At this stage, internal documents available in the partner network, written information by the DSOs in national language (e.g. network development plans and online tools such as heat maps), material provided by national authorities and stakeholder reports submitted to national associations are considered.

Completion of knowledge base with interview study

The subsequent interview study complements the findings of the desk research. To address the open points from the desk research, the MS experts collect **qualitative primary data** through interviews in the respective MS. To maximize the added value of each interview, the interviews target gaps in the knowledge base with a focus on specific stakeholders and design categories. The open points raise questions on (1) how certain arrangements work in practice and (2) the trade-offs behind the arrangements. The latter concerns trade-offs between (a) the realization of policy targets and complexity, as well as (b) harmonizing arrangements and accepting structural differences between stakeholder groups and MS. We prioritize knowledge gaps on key design features over the ones on MS specific idiosyncrasies. In addition, the study aims to maintain geographical balance, noting that there is strong heterogeneity across MS that is also shaped by grid conditions and economic situations across MS so that selected practices are needed but not unconditionally transferrable.

Key stakeholders are mapped for the interview study specific to the knowledge gaps in each MS. The focus is on national-level representatives from regulatory bodies, energy ministries, DSOs and their associations, and grid user representations (core stakeholder group). In addition, the interview study includes representatives of companies whose work addresses the implementation of current regulation in the market (i.e. service providers, research organizations). Concerning the multiple combination options of design features, MS and stakeholder groups, we pursue a targeted approach focusing on prioritized aspects of the design features and the affected stakeholder groups. This first round of prioritization is developed from a review of the preliminary fact sheets in the desk research, which is formalized through the first interim report of the study. This is operationalized with the topic leads formulating questions of interest for the design categories. For example, in Topic 1 on network development, the review of desk research showed that in many MS, there are very different documents related to network planning and very little comparability within MS. Hence, for the design category of harmonization of DNDPs, the leading question for interviews was: Is there a document (e.g. by the NRA, Ministry, or DSO industry association) that summarises key outcomes / impacts of the various NDPs?

The interviews are semi-structured, as their primary purpose is to fill knowledge gaps along the design features and categories in light of the information already gathered from desk research. Written consultations can substitute for interviews in cases where only little clarifications are missing or an interpretation of an existing piece of information is needed. This is intended to realize efficiency gains and subject to the decision of the MS expert who gathered the desk research in the first stage. In terms of process, the MS experts in exchange with the topic leads choose the priorities and questions based on the gaps in the desk research. These are checked and confirmed by the topic leads, whereas the execution is done by the MS experts.

This concludes the first phase of the study, i.e. **Task 1**: the data collection for a comprehensive overview across the 27 MS. More information on the interview composition is provided in the last subsection of this Appendix.

Research alignment across MS and topic areas

Tasks 2 to 4 cover the second phase of the study. The common aim across the three tasks is the in-depth assessment of the key design features for network development planning (**Task 2**), network tariff regimes and regulatory incentives (**Task 3**), and grid connection requests (**Task 4**).

To structure the progress in this phase from the descriptive nature of the input data from **Task 1** to the delivery of an in-depth assessment, we then conduct a synthesis of the data collection. The challenge is to transition from data collection at MS level to a comparative analysis at topic level. This also requires alignment across topics.

In a first step, the topic leads extract the design features for each design category from the MS fact sheets of Task 1 and checks the insights against the overview of the design features from the matrix structure. From this, we identify **priority themes** for each topic that warrant further attention. Priority themes can be cross-cutting to design categories when similar issues run through a topic in multiple aspects.

In the second step, **topic-MS combinations for further deep dive** examination are selected. An example for such a combination of topic-by-MS could be: Flexibility integration (topic) in Austria (MS).

The topic-MS combinations for deep dives are selected based in particular on:

a) the geography and grid conditions (in particular, their particularities) to ensure a spread of different characteristics and capture the spatial distribution of MS.

b) the relevance with respect to the in-depth assessment of key design features, which are selected by the topic leads based on a first review of the knowledge base.

c) the availability of data, which will also be an important criterion to select MS practices and can at this point be assessed by MS experts.

Based on these selection criteria, each topic lead prepares a suggested list of topic-MS combination per priority theme. This list is circulated to MS experts, who provide input based on their experience from the desk research. This ensures that data availability risks are mitigated and missed opportunities from overlooked features are avoided. The resulting short lists for each topic area are then brought together in an internal alignment workshop between the Topic leads to discuss the final selection for the deep dives. This was conducted on March 18, 2025.

In-Depth assessment of selected practices

This alignment gives the basis for the analytical work to proceed within the three topic areas towards the further development of the study. Based on the alignment (see section 2.3 above), the final selection of deep dives is made and these practices are analysed in more detail.

This process was adjusted relative to the plan at inception after a review of the data collected in Task 1 and in light of the identified priority themes. Instead of selecting a fixed number of focus MS across topic areas as initially planned, it was deemed necessary to be more flexible and select different MS for each topic area to fit the objective of the study. This is motivated by the findings revolving around heterogeneity and different novel aspects being tried in different MS. In addition, different needs emerged by topic area. For example, in Topic 1, fewer selected practices and more room for comparing aspects *within* a DNDP are deemed appropriate to understand the complexity of network planning. In Topic 2, by contrast, more different design options from different MS needed to be selected with a focus on how they achieve overarching principles (e.g. cost-reflectivity). In Topic 3, the preferred procedure was to stick to selection by design category due to the challenge to differentiate aspects of the process given the high level of fragmentation in the topic area. The current, adjusted approach with topic-MS combinations accommodates these different needs identified by the respective topic leads.

Across all three topic areas, the analysis is based on material collected from both the desk research and the interview study and supplemented where needed through further investigation, in particular from national documentation collected by MS experts. Formal elaboration is the responsibility of the respective topic leads, in order to ensure a comparative perspective and an emphasis on whether selected practices are transferrable across the EU-27.

The deep dives follow a common structure, although scope and focus points vary based on the particularities of the topic area.

Context for the practice briefly introducing the background that renders the deep dive important for the study and explains the conditions under which the action is implemented

Body of content explaining the selected practice or method, tailored to the need of the specific deep dive. For example, regulatory aspects supply more references to legal texts, whereas implementation questions might link to the tools employed.

Evaluation of the practice in the context of the EU-27. This last part is focused in particular on advantages and challenges, as well as the potential for adaptability for other MS.

Formulation of recommendations

In the last phase of the study (**Task 5**), recommendations are developed. These recommendations serve two purposes. Regarding action at the European level, they aim to identify where and how the EU can support the development of distribution grids along the three topic areas. In this context, the study connects with and builds on the **Grid Action Plan**. Regarding the findings that emerge from the deep dives in particular, the recommendations address stakeholders also at the national level. The selected practices give insights on how MS face, address and solve challenges arising through the energy transition in distribution grids across the EU-27. While not all of these insights can be considered best practices with unconditional transferability to all MS, the insights provided therein do offer meaningful information on design options and implementation aspects with relevance for DSOs and NRAs. The recommendations link the findings from the MS level to the policy developments at the EU level: they assess how aspects revolving around distribution grids align with EU objectives and where gaps are apparent.

Interview composition

The interview study was conducted between January and March 2025, with follow-ups in some cases going into April.

Contacts were initiated by MS experts and in national language where possible. The interviews were conducted as semi-structured (see methodology above). Written consultations were used for simpler clarification questions in addition. More than 80 institutions were contacted, some of which suggested alternative contacts.

The stakeholder composition is shown in **Figure 4**.

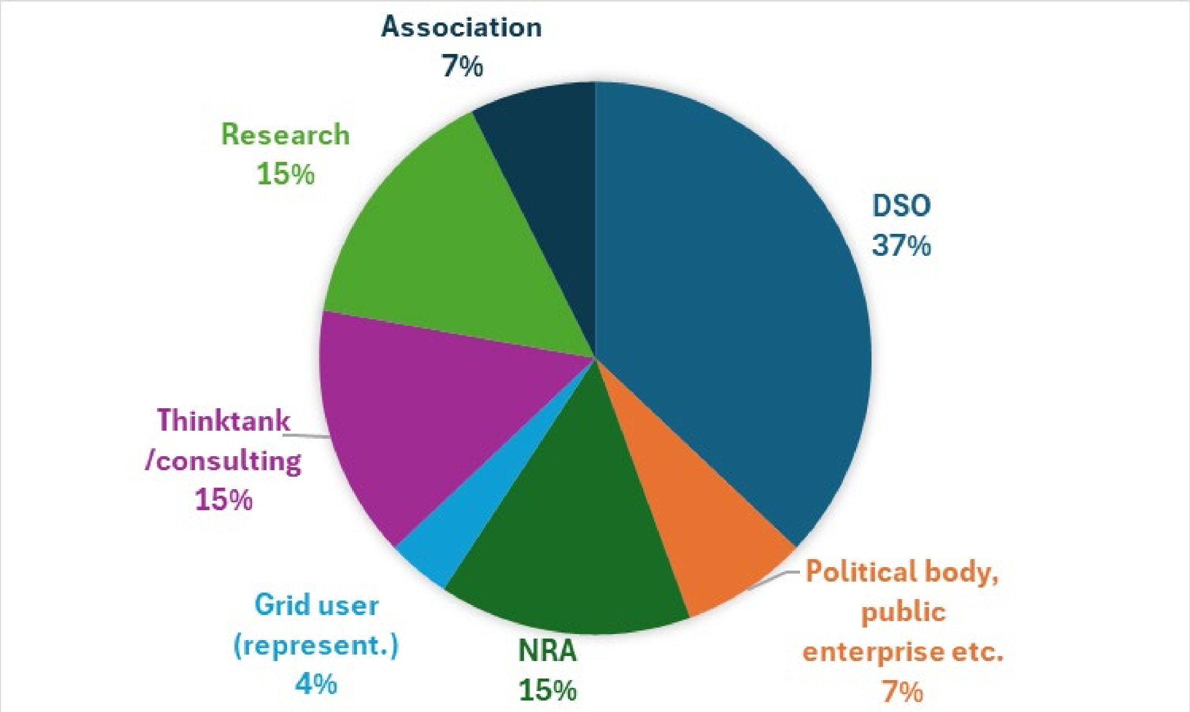

Figure 4: Composition of stakeholders in relative terms

This composition comes from 19 semi-structured interviews and 8 written consultations. **Table 12** contains the list of stakeholders who provided input with the type of organization and the MS they represent/come from.

Table 12: List of stakeholders consulted by MS and organization type

MS	Organization
AT	DSO
BG	DSO
BG	Research
DE	DSO
DE	Thinktank/consulting
DE	Grid user (representative)
DK	Association
DK	NRA
DK	Political body
ES	DSO
ET	NRA
FI	Research (with previous experience working for DSO)
HR	DSO
HR	DSO service provider
HU	DSO
HU	DSO
HU	NRA
IE	Political body
LU	DSO
LV	NRA
NL	DSO
PL	Thinktank/consulting
PL	Thinktank/consulting
RO	Research
SE	Association
SI	Research
SK	Thinktank/consulting

In a small number of MS, it was not possible to complete interviews successfully or the desk research was sufficient to fill all data. In these cases, the fact sheets are based on desk research. These MS are: CY, MT, BE, FR, GR, IT, LT, PT, CZ.

In the case of CZ and DE, additional information was drawn from workshops on relevant topics at the national level. In addition, participation in a closed workshop by ACER in 2024 on network development planning contributed to the knowledge base for the following MS: ES, PT, IT. In addition, feedback from a public stakeholder workshop organized by DG ENER in June 2025 provided information that was duly incorporated (elaborated in the following subsection).

Workshop on distribution grids

The workshop took place on June 27, 2025 and was conducted as a public three hour online session hosted by DG ENER via Webex. **The first session** collected feedback on the study results, especially the recommendations for topic areas 1 and 2 (i.e. network development planning and network tariff regimes). **The second session** included the study results from topic area 3 on grid connection requests, but was also part of the stakeholder consultation for the Commission's upcoming guidance on grid connections. The following summary focuses on input for the study rather than questions on clarification or examples.

Regarding **network development planning** in the first session, stakeholders asked for better distinction between flexibility forecasting and flexibility assumptions and for specific examples of grid-enhancing technologies. DSO representatives raised the need for investment rules to allow DSOs to adapt to changing conditions. It was also pointed out that harmonization at EU level should consider NRA competence on distribution, especially considering heterogeneity across EU DSOs. There is agreement that the aim should be better accessibility, not increasing workload with double structures. In addition, stakeholders noted the importance of considering the evolving policy framework, relating DNDPs to the Electricity Market Directive and the Network Codes.

Written comments (chat function) asked about how enforcement of existing legislation can be ensured, but also pointed to limitations in what DNDPs can serve (i.e. strategic planning, but not planning on a per-asset basis, especially at lower voltage levels). In addition, DSO representatives cautioned that while a common platform for DNDPs could have value, this should only apply to final plans, not consultation, since national bodies are already working on this and there is a risk of overly structured consultation requirements. This information from the chat is closely related to the discussion about harmonization that took place verbally (see above).

Regarding **network tariff regimes**, there were several questions on the recommendations for network tariff design, i.e. how complexity can be handled in MS with many DSOs, how the implementation of dynamic tariffs, and how injections charges can proceed, especially in light of the different pre-conditions present in the MS. Critical points from stakeholders were raised regarding the cost of flexibility use, which is currently not clear how it can be assessed, as well as the consideration of distributional effects and different user groups in practice.

Written comments (chat function) raised additional points to be considered. For anticipatory investments, this concerns the possible tension between allowing anticipatory investments and maintaining efficiency targets. The consideration of energy communities as a new, and specifically local user group in tariff treatment was stated. The questions overall emphasized that stakeholders are in search of best practices and especially practical experience with implementation of novel network tariff designs to understand the value and consequences.

For the second session, the following focuses on summarizing the input received for the study results pertaining to **grid connection requests**. It was noted that the drivers of backlogs should include shortcomings in network planning. In addition, the consideration of "use it or lose it" policies was brought up as a measure for queue management. Several questions related to prioritization were raised, for example regarding the possibility to refuse certain connections, the competition smaller projects (energy communities) face against larger projects, and the distinction between RE projects not being viable while at the same time sound projects remain in the queue because build-out was not planned sufficiently. DSO representatives also emphasized that prioritization schemes do not fall within the competence of the DSOs, who are instead bound by legislation.

Written comments (chat function) provided further input to problems and solutions. Relating to "use-it-or-loose-it" policies, stakeholders noted that they see cases of grid users increasing their capacity limits ex-post, referred to as "uncontrolled growth". Possible solutions from Sweden and Finland making using mutually beneficial loads in prioritization, and from the UK reforming the prioritization scheme were referenced explicitly. Regarding flexible connection agreements, it was noted that an assessment of their activation and market integration would be helpful, and that this discussion links to the network code on demand response. It was also noted that DSOs specifically can help with grid queues by engaging in communication to better understand what grid users need and thus identify ways to use scarce capacity more efficiently.

Stakeholders were also invited to present in the workshop. Presentations were given by: the EU DSO Entity, Wind Europe, Geode, ChargeUp Europe, E.DSO and the European Seaports. From these presentations, it becomes clear that there are divergent views on responsibilities and progress among the various actors, despite a common agreement on the challenge and the need to speed up process. In particular, grid user representatives push for more transparency, harmonization, and faster action in the regulated segment of the energy market and from the DSOs in particular. This group of stakeholders also points to the particular needs of the use cases they represent, e.g. mobility being transnational by default, or seaports serving as industrial complexes with high electricity demand beyond the maritime transport itself. On the other side, DSO representatives note that DSOs stand ready to enable the needed transformation, but that framework conditions need to be adjusted to allow them to act effectively on their new position in an increasingly decentral energy system. In this context, it was also emphasized that while flexibility and flexible connections agreements can help, there is a need to link these discourses more closely to investments and long-term approaches in general.

Getting in touch with the EU

In person

All over the European Union there are hundreds of Europe Direct information centres. You can find the address of the centre nearest you at: https://europa.eu/european-union/contact_en

On the phone or by email

Europe Direct is a service that answers your questions about the European Union. You can contact this service:

– by freephone: 00 800 6 7 8 9 10 11 (certain operators may charge for these calls),

– at the following standard number: +32 22999696 or

– by email via: https://europa.eu/european-union/contact_en

Finding information about the EU

Online

Information about the European Union in all the official languages of the EU is available on the Europa website at: https://europa.eu/european-union/index_en

EU publications

You can download or order free and priced EU publications at: https://publications.europa.eu/en/publications. Multiple copies of free publications may be obtained by contacting Europe Direct or your local information centre (see https://europa.eu/european-union/contact_en).

EU law and related documents

For access to legal information from the EU, including all EU law since 1952 in all the official language versions, go to EUR-Lex at: http://eur-lex.europa.eu

Open data from the EU

The EU Open Data Portal (http://data.europa.eu/euodp/en) provides access to datasets from the EU. Data can be downloaded and reused for free, for both commercial and non-commercial purposes.

MJ-01-25-121-EN-N

Publications Office
of the European Union

doi 10.2833/9351025