

Communication Working Group

Smart Distribution Grid Planning

Casebook

Editor: Susanne Windischberger

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About ISGAN Discussion Papers

ISGAN discussion papers are meant to provide input to the global discussion about smart grids. Each is a statement by the author(s) regarding a topic of international interest. They reflect works in progress in the development of smart grids in the different regions of the world. Their aim is not to communicate a final outcome or to advise decision-makers, but rather to lay the groundwork for further research and analysis.

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Abstract

This casebook is one of the outcomes of ISGAN's Lighthouse Project on **Long-Term Planning and Implementation for the Evolution of Smart Distribution Grids**. ISGAN, the International Smart Grid Action Network under the International Energy Agency and the Clean Energy Ministerial, brings together 25 member states and the European Commission to advance knowledge sharing on smart, clean, and flexible electricity grids. Within this framework, the Lighthouse Project combines contributions from ISGAN's working groups with a dedicated knowledge-sharing process involving internal and external stakeholders.

The casebook examines thirteen cases from ten countries, highlighting innovations in smart distribution grid planning across a structured framework of five planning phases: foresight, strategic decision-making, long-term planning, assessment and decision support, and implementation. These phases are influenced by three cross-cutting framework conditions: legal and governance arrangements, actor coordination and collaboration, and information and knowledge infrastructure. Particular attention is given to the roles of policy makers, regulators, local and regional governments, distribution system operators, utilities, and grid owners.

The cases cover a broad range of themes, including communication and collaboration platforms, network planning tools, predictive asset management, flexibility needs and markets, distributed energy resource management, and integrated net-zero community development. Together, they demonstrate how digital tools, scenario-based planning, interoperability frameworks, flexibility mechanisms, and stakeholder coordination can support more efficient, resilient, and adaptive distribution grids.

The findings show that distribution system operators are actively investing in innovative planning methods and technologies, with clear benefits for customers and communities. At the same time, successful implementation depends on high-quality data, continued technology demonstration, supportive legal frameworks, and evolving actor roles and interactions across the power system.

Executive Summary

ISGAN

ISGAN, the International Smart Grid Action Network, is a Technology Cooperation Programme (TCP) of the International Energy Agency (IEA) and an initiative of the Clean Energy Ministerial (CEM). ISGAN was founded in 2011 and has 25 member states plus the European Commission as members.

ISGAN is an international platform that facilitates the **development and exchange of knowledge and expertise on smarter, cleaner, and more flexible electricity grids**. It enables dynamic **knowledge exchange, technical assistance, peer review, and activity coordination** among its participants and stakeholders. ISGAN is structured into six working groups and is overseen by an executive committee and a chairmanship consisting of one chair and three vice-chairs.¹

Lighthouse Project

One of ISGAN's key activities is the Lighthouse Project, which brings together all working groups to focus on a single central topic supported by a knowledge-sharing initiative. This initiative consists of workshops that promote not only knowledge exchange but also collaboration and co-creation among internal and external stakeholders. It addresses political, economic, technological, and social factors, as well as the interactions among diverse actors, including distribution system operators, municipalities, regulators, technology providers, and end users.

The current Lighthouse Project focuses on *Long-Term Planning and Implementation for the Evolution of Smart Distribution Grids*. This Casebook has been produced as part of that effort.

Casebook

The purpose of this Casebook is to:

- share information on innovations and pilot projects of some ISGAN member countries
- present comparative studies and analysis of these innovative cases
- share information with emerging economies and countries with less developed power grids
- showcase innovations in the field of smart distribution grid planning

This Casebook focuses on the lighthouse topic of smart distribution grid planning and is based on the ISGAN Lighthouse framework in which the five phases of distribution grid planning are:

1. Foresight
2. Strategic decision making
3. Long-term planning
4. Assessment and decision support
5. Implementation

¹ [ISGAN in a Nutshell](#)

These phases are influenced by three framework conditions:

1. a legal and governance framework
2. the actor coordination and collaboration framework
3. the information and knowledge infrastructure

The five phases and three framework conditions create a framework, which is used to structure the results of this work. A particular focus of the project are the actors who contribute and benefit to the innovations: the energy policy makers, regulators, local and regional governments, distribution system operators/utilities, and grid owners.

Overview of cases

This collection of cases contains 15 cases from ten countries. They can roughly be sorted in the following topics:

Topic	Cases
Communication framework or platform	Sweden 1, Sweden 2, Japan 3
Tool for network planning	Austria1, Austria 2, Germany 1, Switzerland
Asset management	Denmark, Germany 2
Flexibility needs and markets	Italy, Spain, Japan 3
DER Management	Australia, Japan 1, 2
Others	Canada (energy community)

Australia: In support of Australia's interoperable energy future, the Australian Common Smart Inverter Protocol (CSIP-AUS) was developed and employed to enable dynamic operational envelopes (DOEs) through a **secure, internet-based communication protocol between utility networks and inverter-based DERs** (e.g., smart inverters) instead of static export limitations. DOEs are time-varying limits on the import and export of power at a customer's connection point (site), which are determined based on prevailing network conditions such as voltage limits, thermal limits, and the available hosting capacity of the distribution feeder. A trial involving more than 400 residential customers was executed, and the protocol is now being implemented across Australia.

Austria Case 1: An Austrian distribution system operator (DSO) developed a tool together with a technology provider that allows **smart meter data-based state estimation of the whole DSO power grid**. This tool guides network measures like network planning and asset management.

Austria Case 2: Austria's second case describes **a method for quantitatively assessing future medium- and long-term grid expansion needs** in medium- and low-voltage networks under different consumption and feed-in scenarios. The assessment is based on scientifically developed future scenarios and considers various grid expansion measures. It enables the derivation of key requirements for grid customers, planning principles, identification of potential grid weaknesses, and insights for future construction standards.

Canada: This case aims to demonstrate Canada's first large-scale fully integrated net-zero energy community and shows that that net-zero is feasible at the community level. Technology-wise, the net-zero community hosts a DC microgrid with connected battery and PV systems. The regulator, the Ontario Energy Board, released a community net metering regulation allowing renewable energy projects in the community development to allow **electricity generation credits across multiple facilities**.

Denmark: In this project, a **complete, software-based toolchain for predictive asset management**, centered around the PAMSEN (Predictive Asset Management Smart Energy Network) toolset was developed. The team created a Neural Weibull Proportional Hazard (NWPH) modelling pipeline that estimates cable-level hazard, reliability and fault vulnerability from GIS, asset and failure-history data. The model is censoring- and truncation-aware and is embedded in a Bayesian nested Monte Carlo simulator, producing risk-aware rankings and uncertainty measures for every underground cable.

Germany 1 (Joint regional scenario): Driven by climate neutrality target and regulatory requirements, DSOs have jointly developed six regional scenarios, shifting from fragmented top-down planning toward **a coordinated approach built on shared assumptions and transparent data exchange**. Working with TSOs, municipalities, and industry associations, these scenarios serve as a common reference for long-term grid expansion plan across the country. The long-term goal is for this process to become standard planning practice, repeatable by the same organisations and replicable by others.

Germany 2 (Schwerte): The core of the approach is the establishment of a **consistent overall process within an asset management system** in accordance with ISO 55001, which systematically translates corporate goals and strategies, such as decarbonisation, into concrete construction measures.

Italy Case 1: Developed a medium- to long-term distribution network planning approach that **evaluates flexibility needs using stochastic power-flow analysis and a dedicated cost-benefit assessment**, replacing the former “plan for any violation” paradigm. The new tools explicitly value technical and financial options such as generator dispatch, demand-side integration, transformer tap control, reactive power management, and online reconfiguration. A large Italian case study showed how DER flexibility affects a grid with many PV plants, high electrification, balanced feeder-level consumption and production, and still relatively low electric mobility.

Italy Case 2: Involves the development of a **new digital portal designed to support efficient territorial planning**. It was created in response to a rapid increase in connection requests to the National Transmission Grid (NTG) and the lack of an effective system for information sharing between Terna and the authorising bodies regarding plant development initiatives. The portal aims to provide the transparent, readily accessible information needed for territorial planning and to support stakeholders involved in the connection process.

Japan Case 1: Japan's innovation was developing a control system for its “Connect and Manage” approach to enable early, cost-efficient renewable interconnections by better utilising existing grid capacity. It addresses the challenge of integrating large volumes of renewables while limiting unnecessary grid expansion and social costs by actively managing congestion through curtailment when grid congestion is expected. The system enabled the introduction of non-firm grid connections, allowing generators of 10 kW or larger in distribution grids to connect earlier even when capacity is insufficient, provided their output can be curtailed during congestion.

Japan Case 2: Japan's second innovation is developing and validating technical solutions for community microgrids that use inverter-based renewable energy sources as the primary power supply. It addresses the challenge of ensuring stable and secure operation during islanded conditions, where conventional protection and restoration schemes may no longer function effectively. Through a NEDO project involving utilities, manufacturers, and research organisations, new approaches were studied for black-start restoration, ground-fault detection, and short-circuit protection. The solutions were successfully demonstrated through field verification tests, providing a pathway for the practical deployment of renewable-powered community microgrids and strengthening power-system resilience against natural disasters.

Japan Case 3: Japan's third innovation is developing a DER Flexibility System to mitigate distribution-grid congestion and enable more efficient integration of renewable energy. It addresses the challenge of accommodating growing volumes of distributed renewable generation without waiting for costly network reinforcement, while reducing renewable curtailment and making better use of existing grid infrastructure. Under a NEDO project, a framework was established in which DSOs, that are the same companies as TSOs can procure and activate flexibility from distributed energy resources through aggregators and a dedicated flexibility platform. The approach enables congestion management at the distribution level by coordinating batteries and other flexible resources, helping defer grid investments, accelerate renewable interconnections, and support the transition to a more flexible power system.

Spain: The Spanish case is part of a Regulatory Sandbox aimed at advancing flexibility and active network management. It centres on the SIORD platform, a national data exchange system that connects all distribution grid stakeholders. SIORD improves the monitoring, control, and coordination of distributed resources and, through interoperability with OMIE's market platform, **enables local flexibility markets where consumers, producers, and aggregators trade services aligned with grid needs.**

Within this framework, S2F will test flexible connection arrangements with variable access conditions—such as peak-hour restrictions or temporary disconnections—alongside local flexibility markets to optimize grid capacity and overall system performance.

Sweden Case 1 (Collaboration platforms): To accelerate and co-create better solutions for grid planning and grid implementation, several collaboration platforms have been established in different parts of Sweden in recent years. The collaboration platforms are structured around a central forum that meets four times a year to **exchange information and coordinate strategic topics.** A dedicated secretariat manages the operational work and ensures continuity between meetings. In addition, specific focus groups were established to foster strategic collaboration in the areas of hydrogen, the power grid, and energy planning. Further activities—such as dialogue meetings, panel sessions, and conferences—are initiated as needed based on emerging priorities and identified demands.

Sweden Case 2 (Collaboration platform in the Skåne Region): Centres on a new collaboration platform gathering regional actors with the ability to jointly create optimal conditions to enable the electrification needed for climate change mitigation, sustainable growth, and societal modernisation.

The **collaboration platform** involves several different actors including **Region Skåne**, the county administrative board (Länsstyrelsen), government of the largest municipalities in the region, the largest local grid operators (in Sweden the grid operators also own their grid), power producers, and industry representatives.

A management group runs the operational and administrative issues of the collaboration platform. The work is guided by a roadmap for 2030 including a clear joint vision, identified needs and suggestions on how to bridge any gaps.

Switzerland: The innovation is a target **network planning tool that creates time series and optimises grid development** based on two pillars: regionalising national scenarios and performing grid planning analyses to define upgrades and investment costs. National adoption targets for PV, heat pumps, batteries, and EV charging are translated to the utility's service territory, and detailed grid models capture topology, assets, and all load and generation connection points. The framework can apply measures such as PV curtailment, smart heat pump operation, and smart EV charging individually at each connection point.

Insights from the case studies

Transition to flexible, active grid management: Power systems are moving from static planning and fixed export limits to dynamic, real-time management using flexible connections, DER control, and active congestion management. This improves grid utilisation and defers costly upgrades.

Digitalisation and data as core enablers: Advanced digital infrastructure, such as interoperable platforms, real-time data exchange, and analytics, is becoming foundational for modern grids, enabling visibility, coordination, and smarter decision-making across all actors.

Market-based flexibility and new business models: The rise of local flexibility markets and aggregators is transforming how grid services are procured, shifting toward market-based approaches that better align DER participation with system needs.

Forward-looking, scenario-based planning: Grid planning is evolving into a probabilistic, scenario-driven discipline that accounts for uncertainty in electrification, DER uptake, and policy. This supports more resilient, cost-efficient investment decisions.

System-wide collaboration and governance: Effective transformation requires structured collaboration across DSOs, TSOs, regulators, industry, and communities, supported by shared data, common scenarios, and coordinated planning frameworks.

Regulatory innovation as a key accelerator: Regulatory frameworks are adapting, through sandboxes, new market rules, and non-firm access models, to enable experimentation, scale innovation, and unlock flexibility.

Growing role of distributed and local energy systems: Community energy systems, microgrids, and high DER penetration are shifting the grid toward a more decentralised, system-oriented model, requiring new technical and operational approaches.

Further insights from the case studies include:

- DSOs invest in the future of their grid planning, they take part in innovative projects, develop new methods, tools and platforms
- Customers benefit from these innovations
- Available data is still crucial for the implementation of new tools
- Technology demonstrations need to be done
- In many cases there is a need to adapt the legal framework in a country or the EU.
- The roles of actors in the power system need to change or their interactions need to adapt to accommodate new methods and tools. Their interaction is essential.

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1. Introduction

Across the globe, power grids are being digitalised and modernised into “smart” systems capable of sensing conditions, communicating, and actively balancing supply and demand in real time. Yet progress is uneven. While some regions are deploying advanced metering, automation, and flexibility markets, others are only beginning to electrify and are building foundational grid capacity.

Europe has the most resilient and interconnected power grid in the world.² In contrast, electrification is in the early stages in many countries, and numerous well-established grids face ageing infrastructure. Alongside these challenges, the energy transition introduces additional layers of complexity: increasing shares of renewable energy, the rise of prosumers, and the emergence of new market roles. Together, these developments require new approaches to planning and operating future power systems, including improved processes, tools, and communication.

In recent years, several European and international publications and regulations have focused on grid planning and distribution grid challenges, for example:

- The Draghi report emphasises that investment in clean electricity generation alone is insufficient; it must be accompanied by parallel efforts to upgrade and modernize grid infrastructure and enhance system integration, including through innovative and digital solutions, to ensure a successful energy transition.³
- In their report, *Electricity 2026*, the IEA calls the current period in time “the age of electricity”.⁴ For the first time in three decades, excluding periods of crisis-related disruption, global electricity demand outpaced economic growth in 2024, trend expected to continue. The report projects a raise in electricity demand by 50% compared to the average growth over the past decade.
- The international Energy Agency (IEA) published a highly relevant report *Electricity Grids and Secure Energy Transitions*.⁵ This report provides a comprehensive overview of the current state of global electricity grids, examining aspects such as grid infrastructure, connection queues, outage costs, grid congestion, generation curtailment, and development timelines. It highlights emerging signs that grids are becoming a barrier to the transition to clean energy and analyses the risks associated with the potential slow pace of grid development and reform. A key finding was that, within the next decade, as much grid infrastructure will need to be built or updated as exists today. Planning the right measures based on data is one of the key topics in the cases in this Casebook.

In Europe the directive (EU)2019/944 sets common rules for the EU’s internal electricity market.⁶ It includes the requirements for DSOs to publish Network Development Plans (NDPs) (Article 32) to establish a forward-looking perspective to 2040. The *EU Action Plan for Grids* highlights the need for faster, more flexible grid development to support Europe’s growing energy needs.^{7,8}

² EU Action Plan for Grids. <https://op.europa.eu/s/Akly>

³ Draghi, M. (2024). *The Future of European Competitiveness—A Competitiveness Strategy for Europe*. https://commission.europa.eu/document/97e481fd-2dc3-412d-be4c-f152a8232961_en

⁴ <https://www.iea.org/reports/electricity-2026>

⁵ <https://www.iea.org/reports/electricity-grids-and-secure-energy-transitions>

⁶ 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). Official Journal of the European Union, L 158, 125–199. <https://eur-lex.europa.eu/eli/dir/2019/944/o>

⁷ EU Action Plan for Grids

⁸ eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52023DC0757

It points out that grid investments, especially for distribution grids, need to be accelerated to handle the large-scale integration of renewables and to avoid delays caused by long permitting processes. The action plan also stresses the importance of reducing bottlenecks by streamlining permitting processes and improving coordination between different stakeholders to ensure faster grid expansions.

The status of distribution grid planning was also a topic in the *Study on network development planning, tariff structures and connection requests for electricity distribution grids*.⁹ Apart from appropriate network planning as the primary strategic process, the study discusses network tariff design and regulatory regimes as well as the timely and transparent treatment of grid connection requests.

In general, the current technological landscape is uncertain. For example, it is estimated that 70%-80% of newly installed DER will be connected to the distribution grid.¹⁰ This has a significant impact on DSOs, making it necessary for them to prepare for planning under uncertain framework conditions.¹¹

Planning under uncertainty at the DSO level is the main theme of this Casebook.

During a workshop on the ISGAN Casebook the participants were asked **in one word: what is the biggest challenge in smart distribution grid planning in your context?**

The answers they gave to this question can be found in the following Figure 1.



Figure 1. Biggest challenges in smart distribution grid planning as identified by participants in a Casebook workshop

⁹ European Commission: Directorate-General for Energy, Fraunhofer Institute for Systems and Innovation Research ISI, Guidehouse, Fraunhofer Research Institution for Energy Infrastructures and Geotechnologies IEG and Regional Centre for Energy Policy Research (REKK), *Study on network development planning, tariff structures and connection requests for electricity distribution grids – Final report*, Publications Office of the European Union, 2025. <https://data.europa.eu/doi/10.2833/9351025>

¹⁰ <https://ieeexplore.ieee.org/document/10579937>

¹¹ <https://www.edsoforsmartgrids.eu/technology-radar>

1.1. ISGAN

While there is considerable attention on the role of transmission grids in the electricity transition, distribution grids have fallen behind and need to accelerate their development to fully digitised smart distribution grids to facilitate the required changes. Complex decisions in an increasingly complex power system require new ways of decision making, planning, and operation. [ISGAN](#), the international smart grid action network established for accelerating smart grid development and deployment, has joined the forces of all six of its working groups to focus on the planning and implementation of smart distribution grids under the framework of the Lighthouse Project.

1.2. ISGAN Lighthouse Project and Framework

The **ISGAN Lighthouse Project on Long-Term Planning and Implementation of Smart Distribution Grids** is an international initiative focused on strengthening how distribution grids are planned and developed under conditions of change and uncertainty.¹²

Distribution grids are moving to centre stage in the energy transition. They need to accommodate accelerating electrification and increasingly distributed energy resources while supporting reliable, affordable and resilient energy systems and wider societal objectives. At the same time, enduring grid decisions are being made amid changing demand, technological development, evolving policy priorities and growing interdependencies between sectors, places and levels of governance.

The Lighthouse Project applies a systems perspective to this planning challenge. It brings together knowledge and experience from ISGAN member countries, Working Groups and external stakeholders to explore innovations in technologies, analytical methods, planning processes, institutional arrangements and actor collaboration. Through international knowledge exchange and co-creation, the project seeks to support planning approaches that are more forward-looking, adaptive, integrated and collaborative.

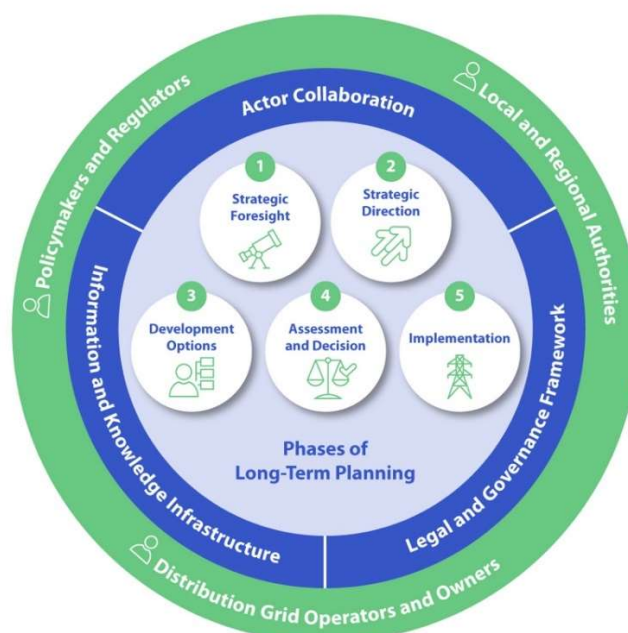


Figure 2. ISGAN Lighthouse Framework for long-term planning of distribution grids

¹² <https://iea-isgan.org/our-work/about-the-lighthouse-project>

A central output of the project is the **ISGAN Lighthouse Framework** (Figure 1).¹³ The Framework provides a common structure for examining the different dimensions of long-term distribution-grid planning and implementation. It connects five planning phases:

1. **Strategic Foresight**
2. **Strategic Direction**
3. **Development Options**
4. **Assessment and Decision**
5. **Implementation**

In practice, these phases overlap and interact, with information, decisions and experience creating feedback across the planning process.

The Framework focuses on three actor groups whose decisions and activities are particularly important and closely interconnected:

- **Policy makers and Regulators**
- **Distribution Grid Operators and Owners**
- **Local and Regional Authorities**

These focal groups operate within a wider actor ecosystem that can include transmission system operators, energy suppliers and aggregators, technology providers, industry and other major energy users, infrastructure and property developers, communities, researchers and civil-society organisations.

Across the actor groups and planning phases, the Framework identifies three enabling conditions:

- **Legal and Governance Framework**
- **Actor Collaboration**
- **Information and Knowledge Infrastructure**

Together, these dimensions help reveal where innovation occurs, which actor relationships it involves, and which wider conditions support or constrain its application.

This Casebook uses the Lighthouse Framework to examine international examples of innovation in long-term distribution-grid planning and implementation. Each case is positioned within the Framework according to the phases, actor groups and enabling conditions to which it most directly contributes. This positioning provides a common basis for navigating and comparing cases from different institutional and national contexts, while recognising that many innovations span several parts of the Framework.

1.3. ISGAN Casebooks

ISGAN has a long tradition of publishing casebooks that showcase successful innovations and pilot projects from around the world. These casebooks help making innovative approaches, tools, and methods accessible to countries looking to adopt similar solutions. Examples can be found on the ISGAN website.¹⁴

In the current **Casebook**, international cases of innovation in the long-term planning and implementation of smart distribution grids were collected, compared and analysed.

The data for the casebook was compiled in the form of a survey. **The methodology** used to gain the data was divided into three parts:

¹³ <https://iea-isgan.org/atest-framework>

¹⁴ <https://iea-isgan.org/case-studies>

1. The template for the Casebook was developed within a workshop with stakeholders from ISGAN, including funding agencies, energy experts and policy makers. They collected the questions in six categories, which can be seen in Figure 3.
2. These questions were implemented into an online survey, to facilitate completion and analysis. The survey was structured into two parts: one about general data from the country as a baseline, and the second part with a description of the innovative case. Apart from a few multiple-choice questions for statistical data, generous space for free text was given to allow for multiple types of answers and different innovations to be described.

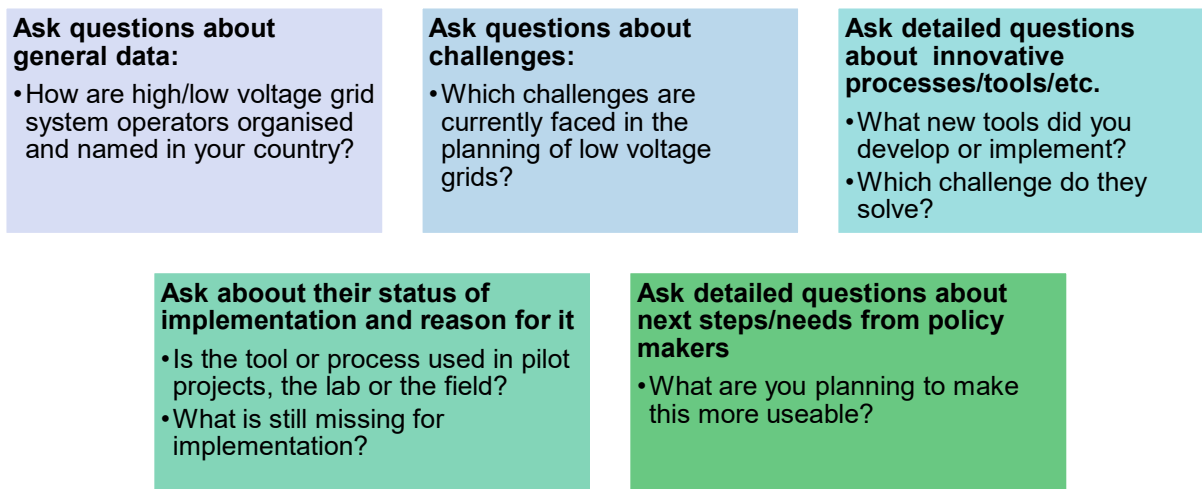


Figure 3. Development of the questions for the ISGAN Casebook template

3. Then, the authors of the Casebook were invited to participate in national meetings with a wide range of stakeholders in order to gather structured feedback, expert opinions, and country-specific insights for the development of the national Casebook chapters. In addition to these meetings, authors also had the option to complete the survey based on their own professional expertise and accumulated knowledge, ensuring that relevant information could still be provided even when stakeholder input was limited or unavailable. This approach allowed for flexibility while maintaining a consistent level of detail and quality across contributions.
4. After the deadline for national casebook contributions all inputs collected were systematically reviewed and analysed by the ISGAN Lighthouse Analysis Team. This analysis aimed to ensure consistency, comparability, and completeness across all national chapters, while also identifying key trends, gaps, and best practices. The standardised template used for this analysis, which guided both the evaluation process and the presentation of results can be found in Appendix A: Questionnaire Template.

1.4. Structure of this document

The Casebook consists of two parts. The first part (Section 2) is the overarching analysis of all cases and of the countries' power systems that contributed to the Casebook. In the second part (Section 3) the individual cases are listed.

2. Overall analysis of results

2.1. Structure and organisation of power systems

When **considering the distribution grid** two different perspectives can be taken: firstly, the technical grid including its different grid levels, and secondly the organisational view of Distribution System Operators (DSOs) and Transmission System Operators (TSOs). The focus of the initiatives in this Casebook is the organisational view. Example topics include what DSOs can do to improve long-term planning, which tools or processes help them, and innovations that have been or can be implemented in the near future to support DSOs. In many cases DSOs themselves were involved in the innovation process for the development of the cases, which is an investment in their future planning processes.

There are several other important actors the DSOs interact with: first and foremost, the transmission system operators (TSOs). There are two different models of DSO/TSO relationships: either all DSOs sit directly under the TSO on the same level (e.g. Denmark) or there are regional and local DSOs in two layers. This means that there are large DSOs directly connected to the TSO and smaller DSOs connected to the larger ones (e.g. Sweden).

All DSOs also interact with their commercial and private customers. In most cases, these customers directly benefit from the innovations.

Other stakeholders that are relevant in this context are power generators, usually several competing companies, the national regulator, markets (day ahead, intraday markets, flexibility markets, balancing market), and the government.

National funding agencies as well as the European Commission finance innovative projects. Universities and research and development organisations work together with the aforementioned stakeholders to conduct research and development projects.

The organisation and nomenclature of power system operators vary significantly across countries, reflecting differences in regulatory frameworks, market liberalisation, and historical development of electricity systems.

In **Australia**, the power grid follows a hierarchical structure where transmission network service providers (TNSPs, acting as the TSOs) operate high-voltage energy highways (typically between 132 kV and 500 kV) to transport bulk electricity from generators across long distances to major load centres. These transmission networks feed into the systems of Distribution Network Service Providers (DNSPs, acting as the DSOs), which manage the last mile of delivery through medium-voltage sub-transmission (typically 11 kV, 22 kV, 33 kV or 66 kV) and low-voltage local lines (nominally 230 V single-phase or 400 V three-phase) that service residential and commercial customers. This organisational framework is overseen by the Australian Energy Market Operator (AEMO), which coordinates the National Electricity Market (NEM) and manages real-time system security, while the Australian Energy Regulator (AER) enforces economic regulation and performance standards for both TNSPs and DNSPs.

In **Austria** there is one TSO, APG Austria Power Grid, and over 120 DSOs. Austria is divided into different grid areas, each of which is served by a specific DSO (e.g. Energienetze Steiermark GmbH, Wiener Netze). There are nine large DSOs and several smaller ones connected to them.

In **Canada**, power system organisation is largely determined at the provincial level. As a result, there is no single national model. Provinces apply different definitions and structures, ranging from vertically integrated utilities to arrangements that separate transmission, system operation, and distribution. Across the country, a mix of TSOs, independent system operators (ISOs), transmission network operators (TNOs), and vertically integrated entities coexist, depending on jurisdiction.

In **Denmark**, transmission and system operation responsibilities are fully integrated within a single entity, Energinet. Energinet acts simultaneously as TSO, ISO, and TNO, owning and operating the high-voltage transmission grid (approximately 132–400 kV), managing system operation and balancing, and ensuring security of supply. There is no separate ISO or TNO. Below the transmission level, local and regional DSOs (also referred to as DNOs, LDCs, or “grid companies”) own and operate the low- and medium-voltage distribution networks and function as regulated natural monopolies. Electricity suppliers and retailers are legally and commercially separate from grid operators and do not own network assets.

The transmission grid is operated by four TSOs in **Germany**, while the DSO operates the distribution level, in which MV is for industrial load and LV for household and small consumers. The DSO also operates HV for large customers. There are 860-880 DSOs in Germany.

In **Italy**, Terna S.p.A. is the sole TSO, managing the high-voltage national grid (~75 000 km). Around 140 DSOs manage the low/medium voltage lines.

In **Japan**, the power system is divided into three levels. An example of the delineation from TEPCO Power Grid is:

- Transmission: 500kV, 275kV
- Sub-transmission: 154kV, 66kV
- Distribution: 22kV, 6.6kV, 200/100V (22 kV may also be classified as sub-transmission).

The voltage levels vary depending on TSO/DSO jurisdiction area. There are 10 DSOs in Japan and all of them are organised directly under the TSO.

Spain follows a more centralised transmission model. There is a single national TSO, while electricity distribution is handled by four large DSOs alongside more than 300 smaller DSOs, each serving fewer than 100 000 customers. This structure combines centralised transmission oversight with a highly fragmented distribution level.

In **Sweden**, Svenska kraftnät (Svk) is the sole state-owned TSO managing the 400 kV/220 kV main grid. Approximately 170 DSOs manage local and regional networks, with Vattenfall, E.ON, and Ellevio controlling 97.7% of regional distribution.

Switzerland has a clearly defined transmission level with a single national TSO, Swissgrid. Distribution is highly decentralised, with around 600 DSOs. These DSOs operate at different voltage levels: some are active across multiple grid levels (levels 3–7), while many smaller DSOs are limited to lower voltage levels (typically levels 5–7) and are connected to regional DSOs.

The total number of DSOs per country is quite independent of the number of inhabitants and differs by an order of magnitude (see Figure 4).

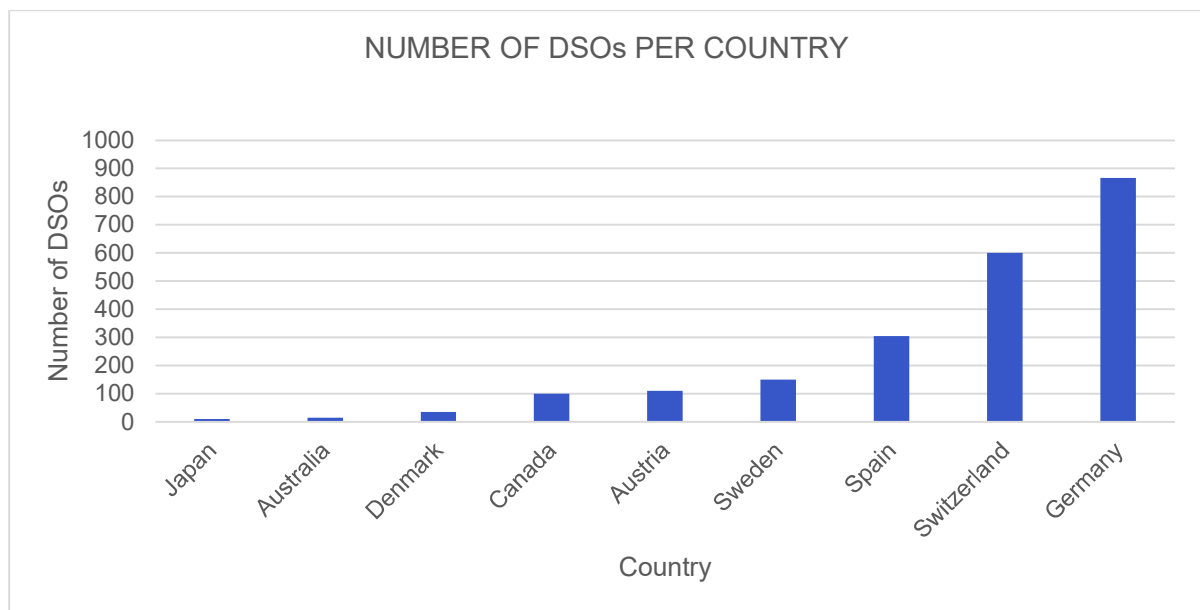


Figure 4. Number of DSOs per country

2.2. Stakeholders involved

Distribution system operators were the main stakeholders contributing to this Casebook. They contributed to 32% of the cases. The second largest groups were energy policy makers (13%) and grid owners (11%). The “others” mentioned in the graph were research organisations (Figure 5).

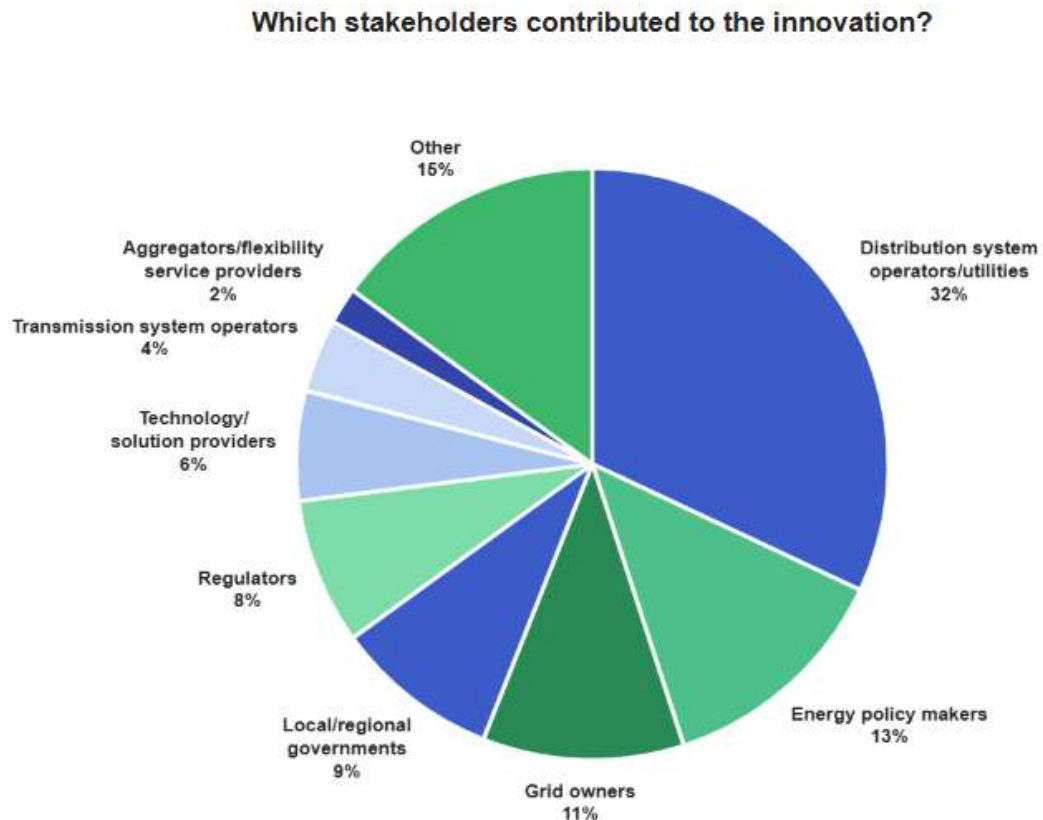


Figure 5. Stakeholders contributing to the innovative cases

While the DSOs were the largest group contributing to the cases, they were also the group most benefitting from the innovations (Figure 6). However, the second largest groups benefitting were the residential customers and prosumers (12%) followed by commercial or industrial customers (8%). Thus, the DSOs have invested to improve the services for both themselves and their customers.

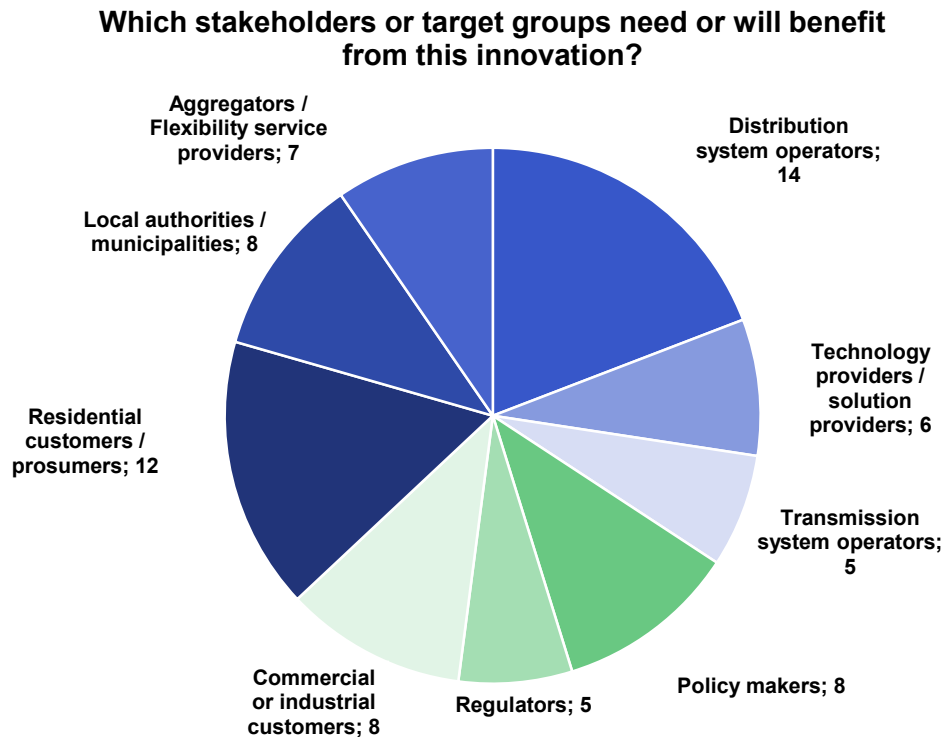


Figure 6. Stakeholders benefitting from the innovation

Most cases had a technical or engineering problem to solve, followed by economical or financial problems. Problems solved included, for example:

- complete, software-based toolchain for predictive asset management
- share best practices for distribution network planning and the use of flexibility
- tool for target network planning (time series creation, optimisation)
- integrated grid planning platform with scenario-based expansion, probabilistic hosting capacity assessment, and connection queue management for wind/repowering/storage
- regional collaboration platforms for cooperative planning
- network monitoring tool consistent overall process within an asset management system in accordance with ISO 55001.

Figure 7 shows the status of implementation for the cases. More than one phase may apply, because tools can be used in the real-world application and still be further developed in an early development stage. Most of the innovations are already in use. For those in development, the necessary next steps for full implementation will be described in the respective case descriptions.

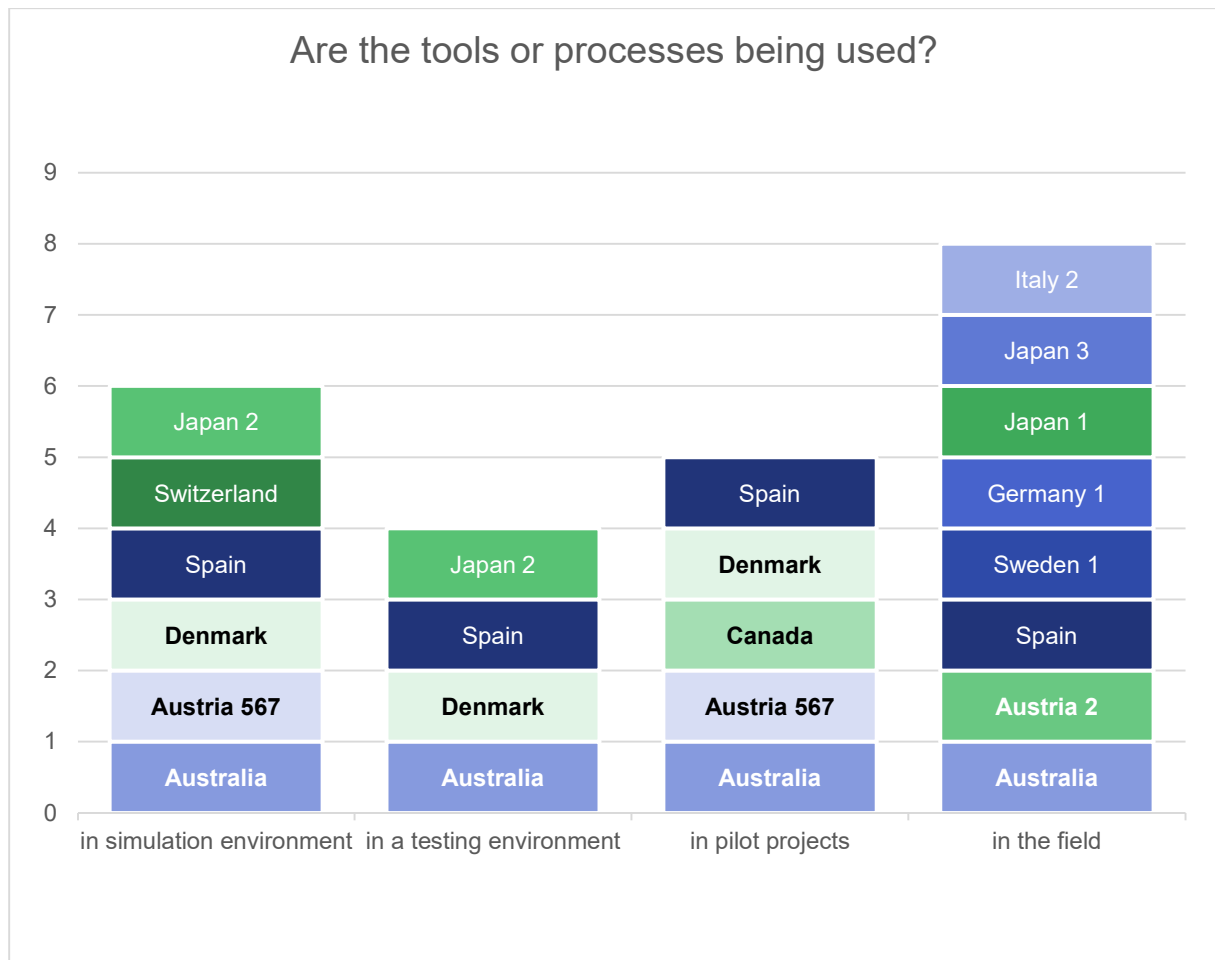


Figure 7. Status of implementation of the innovative cases

2.3. Classification of the cases

This Casebook contains thirteen cases from ten countries. In an overview classification, the cases can be categorised as follows:

Topic	Cases
Communication framework or platform	Sweden 1, Japan 3, Sweden 2, Japan 2
Tool for network planning	Austria 1, Austria 2, Germany 1, Switzerland
Asset management	Denmark, Germany 2
Flexibility needs and markets	Italy, Spain
DER Management	Australia
Others	Canada, Japan 1

The cases submitted were classified into the five phases of long-term planning as shown in Figure 8. Many cases were attributed to several of the phases. There are three cases from Japan and two cases for Austria, Germany, and Sweden. The cases are quite evenly distributed over the phases in the framework, with a maximum of cases in the development options phase.

Phase	Cases
Strategic foresight	Austria 1, Germany 1, Italy 1 and 2, Sweden 1 and 2
Strategic direction	Austria 1, Canada, Germany 1, Italy 1 and 2, Japan 3, Sweden 1 and 2
Development options	Austria, Denmark, Germany 1 and 2, Italy 1 and 2, Japan 1 and 3, Sweden 1 and 2, Switzerland
Assessment and decision	Australia, Austria 1 and 2, Italy 3, Japan 2, Sweden 1 and 2
Implementation	Australia, Austria, Canada, Italy 2, Japan 1, Sweden 1 and 2

Figure 8. Classification of the cases into the five phases of long-term planning

3. Cases

3.1. Australia: Dynamic Operating Envelope (DOE) integration via an interoperable utility-DER communication standard

Author: Nanduni Nimalsiri, Commonwealth Scientific and Industrial Research Organisation (CSIRO)

Contributing authors: Thomas Wearne (CSIRO), Thomas Brinsmead (CSIRO), Michael Elliott (CSIRO), Terijo Lovasz (CSIRO)

Phases addressed: assessment and decision support, implementation

3.1.1. The start

Australia is a global leader in the uptake of distributed energy resources (DER), particularly rooftop solar photovoltaic (PV) systems. Approximately one in three Australian households now has rooftop solar PV, with penetration reaching around 50% in South Australia, Queensland, and Western Australia.¹⁵ The widespread deployment of rooftop solar has led to substantial household power exports into electricity distribution networks, causing some network segments to approach or exceed their hosting capacity, particularly in relation to voltage and thermal limits. To address this challenge, Australian DSOs, known as Distribution Network Service Providers (DNSPs), together with electric utilities, have introduced a range of initiatives aimed at enhancing network capacity and enabling the continued assimilation of distributed solar generation.

One such initiative has been the implementation of export limits at the consumer ‘site’ scale, specifying the maximum amount of power that can be exported to the grid at the customer’s point of connection, as measured by the utility smart meter. These limits have been introduced to manage network congestion and protect distribution networks from voltage and thermal limit violations caused by significant reverse power flows, particularly during weekdays with high solar generation and low residential demand. Historically, these limits were typically set at static (fixed) values—commonly around 5 kW per phase (per site)—and provided a simple and invariably conservative mechanism for maintaining operational performance guarantees.

Although static export limits initially helped mitigate network operational challenges, they have become increasingly restrictive and inefficient as rooftop solar adoption has grown. In particular, static export limits constrain customers even during periods when the network has spare capacity yet may still fail to prevent operational issues during times of high solar generation. Furthermore, they can result in frequent and unnecessary PV curtailment, even when there is no physics-based requirement to do so, and lead to smaller systems being installed than would otherwise be feasible. To address these deficiencies, an Australian innovation known as ‘**Dynamic Operating Envelopes**’ was developed by South Australia Power Networks (SAPN), South Australia’s regulated electricity distributor.¹⁶

¹⁵ <https://www.abs.gov.au/articles/household-solar-electricity-generation-australian-national-accounts>

¹⁶ <https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream>

Dynamic operating envelopes (DOEs) are time-varying limits on the import and export of power at a customer's connection point (site), which are determined based on prevailing network conditions such as voltage limits, thermal limits, and the available hosting capacity of the distribution feeder. Unlike traditional static export limits, which remain fixed regardless of the network state, DOEs vary over time to reflect real-time or forecasted network capacity, enabling higher levels of power exports when the local network can safely accommodate them.

In Australia, the operation of DOEs is enabled through the **Common Smart Inverter Profile – Australia (CSIP-AUS)**.¹⁷ CSIP-AUS is an Australian adaptation of the IEEE 2030.5 (Smart Energy Profile 2.0) protocol, which provides a global standard for secure and interoperable communication between DERs and utility networks.

The innovation is needed by:

DER owners, including both residential and commercial customers, are primary beneficiaries. For example, DOEs can replace a 5-kW static limit with export allowances of up to 10 kW when the network has spare capacity, thereby maximising customer feed-in tariff revenue and improving returns on solar investments.

DOEs also help DNSPs by facilitating the safe accommodation of high volumes of distributed generation. By mitigating technical performance complications associated with reverse power flows during periods of high solar generation, DOEs allow DNSPs to support more efficient use of existing network infrastructure, thereby deferring capital-intensive network infrastructure investments.

Broader energy market stakeholders, including the Australian Energy Market Operator (AEMO) and electricity retailers, may also benefit from DOEs, as they provide useful information and coordination capability to support broader system and market operation. For the wider public, DOEs can enable greater integration of renewable energy, reduce unnecessary curtailment of rooftop solar exports, and contribute to a more reliable and affordable electricity system. Technology providers, including original equipment manufacturers (OEMs), can also gain opportunities by developing products that are interoperable with DOE implementations, for example through CSIP-AUS-compliant client devices.

Since CSIP-AUS is built from SEP 2.0 (Smart Energy Profile 2.0), which is an international standard and open protocol, the work done in Australia should be easily replicable in other countries that could benefit from inverter OEMs having mature solutions and in-house experience.

Support of the management:

The Commonwealth Scientific and Industrial Research Organisation (CSIRO) was part of the DOE Workstream Group, funded by the Australian Renewable Energy Agency (ARENA) under the Distributed Energy Integration Program (DEIP).¹⁸Error! Bookmark not defined.

The DOE initiative has been collaboratively developed and advanced by members of the *DOE Workstream Group*, which has provided strategic leadership, coordination, and guidance to ensure that DOEs effectively facilitate the integration of DERs into Australia's future power system.

¹⁷ <https://www.csipaus.org>

¹⁸ <https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program>

Furthermore, *CSIRO*, in collaboration with *AEMO*, under the **Australian Research in Power Systems Transition (AR-PST)**,¹⁹ developed a research roadmap to explore the critical aspects of DERs in Australia's future power system, identifying DOEs as a key research area. Since 2021, the AR-PST program has actively engaged with numerous universities and industry partners across five research stages, thereby enriching DOE research outcomes through sustained collaborative efforts.

For the ongoing development of CSIP-AUS, *CSIRO* contributes to various working groups that aim to refine CSIP implementation and expand use cases to broader DER applications.

3.1.2. The innovation

In support of Australia's interoperable energy future, CSIP-AUS was developed to enable DOEs through a **secure, internet-based communication protocol between utility networks and DERs** (e.g., smart inverters). CSIP-AUS specifies the standardised messages, commands, and data formats required for DERs to communicate with utilities and with each other, promoting interoperability among devices from different manufacturers and reducing the need for bespoke integrations.

The primary purpose of CSIP-AUS is to ensure that DERs respond to DOE setpoints in a predictable and interoperable manner. As CSIP-AUS is based on a client-server architecture, DERs operate as software clients. These clients typically reside in the cloud but may also be located on the device itself or on intermediary hardware, such as a gateway device capable of administering control. The clients communicate with a utility-managed server that dispatches DOE setpoints.

As a **pioneering developer** of DOEs, *South Australia Power Networks (SAPN)* successfully **demonstrated the practical application** of CSIP-AUS for DOE implementation. Led by *SAPN*, the **Flexible Exports for Solar PV Trial** in 2021-2023 was instrumental in demonstrating the use of CSIP-AUS for DOE (flexible exports) operations.²⁰ The key objective of this trial was to develop and test a standards-based approach, using CSIP-AUS, for communicating flexible export limits between DNSP systems and DER systems supplied by multiple manufacturers. The trial provided valuable guidance for Australian DNSPs and international utilities pursuing DOE adoption. *SAPN* initiated the **trial involving more than 400 residential customers**, initially targeting highly constrained substation areas. *AusNet Services*, Victoria's largest energy network business, also participated in this trial and started implementing reduced export limits at a small number of low-voltage substations that had reached capacity due to increasing rooftop solar penetration across their network.

More specifically, the trial involved a collaborative effort among *SAPN*, *AusNet Services*, *SwitchDin*, *Fronius*, *SMA* and *SolarEdge*, who worked together to develop and trial a new flexible exports customer connection offer for solar PV customers who would otherwise be subject to zero or near-zero export limits. *SwitchDin* developed a modular IEEE 2030.5 CSIP-AUS compliant utility server that was used by *SAPN* and *AusNet* to communicate flexible export limits to customer sites. The functional design of the utility server was codeveloped by *SwitchDin*, *AusNet Services* and *SAPN* with the aim to ensure the implementation was common across both DNSPs.

¹⁹ <https://www.csiro.au/en/research/technology-space/energy/electricity-transition/ar-pst>

²⁰ <https://arena.gov.au/assets/2024/01/SA-Power-Networks-Flexible-Exports-for-Solar-PV-Trial-Final-Report.pdf>

The *SwitchDin* solution leveraged the ‘droplet’, a small gateway device that enabled non-compatible solar inverters to work with the Flexible Exports program. *Fronius* developed a cloud-based integration that allowed their Gen24 range of inverters to participate without any additional on-site hardware. Together, these solutions were the first two CSIP-AUS-capable technologies available on the market. Additionally, both *SAPN* and *AusNet Services* developed new operational systems to calculate and publish flexible export limits.

The overarching architecture governing the operation of DOEs via CSIP-AUS is illustrated in Figure 9. While the high-level architecture is broadly aligned across various DNSP jurisdictions, it is important to acknowledge that the practical implementation of DOEs has varied considerably, reflecting differences in DNSP capabilities, regulatory settings, technology readiness, and deployment priorities. A step-by-step workflow describing DOE operations is summarised below.

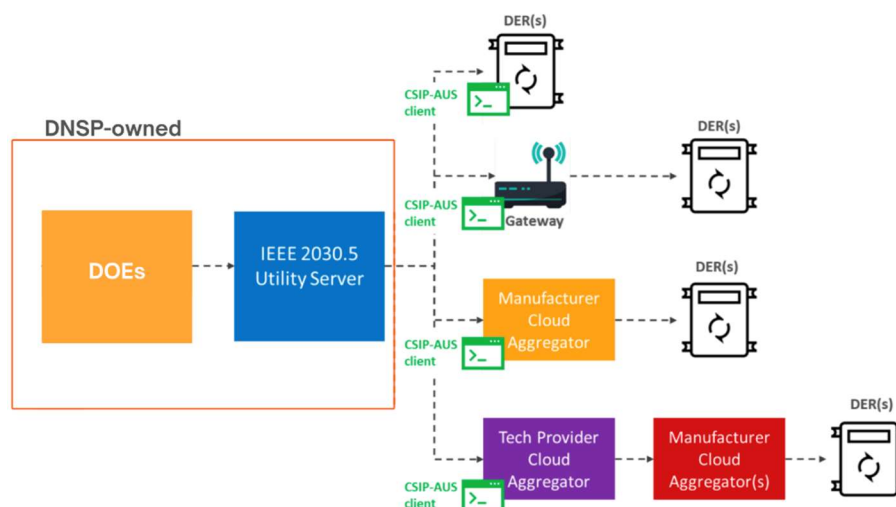


Figure 9. DOEs enabled by CSIP-AUS

Step 1: New DER connection and registration

- Inverter installation: The installer sets up a new solar PV system equipped with a CSIP-AUS compliant smart inverter, which serves as the CSIP-AUS client (direct client embedded in the device).
- Installer commissioning: The installer tests and registers the client with the DNSP.
- Secure handshake: The CSIP-AUS client establishes a secure, encrypted connection (using certificates) with the CSIP-AUS utility server. This is a critical security step enforced by the CSIP-AUS technical standard.

Step 2: DOE calculation

- Hosting capacity calculation: “Hosting capacity” refers to the maximum volume of DER generation that can be accommodated on a distribution network without violating network operational constraints. The DNSP typically calculates hosting capacity by monitoring real-time network conditions, such as voltage levels and thermal loading, and also by employing forecasting techniques to anticipate future network states.
 - *Energex* (South East Queensland’s electricity distribution network provider) calculates hosting capacity at the LV transformer using telemetry data sourced from power quality (PQ) monitors and synthetic power flow models.
 - *SAPN* calculates hosting capacity at the LV transformer based on site-scale load and PV generation forecasts, incorporating live meteorological data to account for variability in generation and demand.

- Determination of DOEs: Once the hosting capacity at the LV transformer scale has been determined, the DNSP calculates the available spare capacity at the LV transformer, representing the remaining margin before reaching the transformer's nominal capacity. The DOE for an individual site is then determined, defining the safe operational limits for DER injection. At present, the same DOE is offered to all sites within a given time interval, with the DOE recalculated according to the DNSP-specific update frequency, which typically range between 5- and 15-minute intervals.
 - *Energex* calculates DOEs by distributing the available spare capacity equally across all connected sites
 - *SAPN* employs a 'waterline' allocation methodology, in which capacity is initially allocated equally across sites, and any unused portion is returned to a common pool for subsequent redistribution among participating sites.

Step 3: Dispatching the DOE setpoints

- The CSIP-AUS utility server sends the calculated DOE setpoints to each client over the established, secure CSIP-AUS communication path.
- After receiving the DOE setpoint, the DER client confirms receipt and acknowledges the instruction.

Note: As shown in Figure 11, when multiple DERs exist at a single site, a local gateway client, often referred to as the master device, can be used to interface directly with the utility server and coordinate downstream DERs at the site. For example, this master device may take the form of a Home Energy Management System (HEMS) with native support for SEP2.0 communications. Alternatively, a third-party cloud proxy (proxy client) or aggregator can offer a cloud or centralised service that functions as a virtual gateway device to control DER at a site in accordance with the received DOE setpoints. Either way, the gateway device is responsible for aggregating and managing communication with individual end-devices, ensuring that DOE setpoints are correctly distributed and coordinated across all end-devices at the site.

Step 4: Inverter compliance

- The inverter adjusts the PV system's generation to ensure it does not exceed the received DOE setpoint.
- The client reports its status and actual export levels back to the utility server, allowing the DNSP to verify compliance and refine future calculations.

Step 5: Fail-safe mechanism

- If the communication path between the client and the utility server is lost (e.g., due to a home internet outage) and the client is unable to refresh the DOE setpoint within a mandated time period, the CSIP-AUS standard requires that the inverter reverts to a conservative, low, static export limit (e.g., 1.5 kW per phase). This failsafe feature ensures that, even during a communication failure, DERs at any site cannot unintentionally destabilise the local network, thereby maintaining reliable grid operation.

3.1.3. The application

The rollout of DOEs in Australia has followed a **staged and incremental approach**. This approach supported the gradual management of customer experience and acceptance, facilitated engagement with solar retailers and installers, and supported the resolution of CSIP-AUS-related issues.

As of 2026, DOEs are being offered by several DNSPs across multiple states and territories within Australia's National Electricity Market (NEM). Building on the success of earlier trials, SAPN has offered Flexible Exports as an option for customers since 2021. *Energex*, which serves South-East Queensland, offers DOEs to customers through their Dynamic Connections program, as an opt-in connection option.²¹

3.1.4. The challenges

Network visibility: The lack of full distribution network visibility constituted the most significant data impediment, limiting the operational effectiveness of DOEs. In particular, limited network telemetry, characterised by sparse sensor deployment and low smart meter penetration, created a fidelity gap that led to significant inaccuracies in early DOE calculations. This highlighted the need to enhance real-time observability and develop more accurate network models.

- DNSPs such as *Energex* and *Ergon Energy Network* are currently investigating advanced methods to calculate distribution network hosting capacity using Distribution System State Estimation (DSSE).²² DSSE combines knowledge of the physical network with time-series measurement data and average loading patterns to estimate the electrical state of the network at any given point in time. The use of DSSE is expected to improve the accuracy and effectiveness of DOE calculations.

Standardisation: Ensuring widespread compatibility of PV inverters with CSIP-AUS is challenging. In the absence of national regulatory requirements, OEMs are not compelled to adopt the standard, creating a significant barrier to large-scale DOE deployment.

- National-scale regulation would likely be necessary to achieve consistent and widespread deployment of DOE-capable devices across Australia.²³ As an initial step, the South Australian Government implemented the "Dynamic Exports Guideline", requiring that all new PV inverters support CSIP-AUS dynamic export limits by 1 July 2023.²⁴ Victoria has also introduced similar regulations, effective from March 2024.

Technical and device interoperability: At the time of initial DOE deployment, the CSIP-AUS technical standard was relatively new, and only a limited number of inverter systems were able to achieve immediate compliance. Specifically, inverters in the early trials from different OEMs exhibited significant variations in their interpretation and implementation of specific protocol features. These discrepancies included differences in the sequence of data retrieval and the execution of secure handshake procedures, which posed challenges for achieving consistent interoperability. To mitigate these challenges, it was necessary to have a testing and certification process to ensure that every PV system receives and interprets CSIP-AUS controls correctly.

²¹ <https://www.energex.com.au/our-services/connections/residential-and-commercial-connections/solar-connections-and-other-technologies/dynamic-connections-for-energy-exports/about-dynamic-connections>

²² https://www.energex.com.au/data/assets/pdf_file/0018/1016415/DMIA-Case-Study-LV-State-Estimation.pdf

²³ https://ieefa.org/sites/default/files/2024-12/BN_How%20rapid%20implementation%20of%20flexible%20exports%20could%20maximise%20rooftop%20solar%20_Nov24.pdf

²⁴ https://www.energymining.sa.gov.au/data/assets/pdf_file/0009/923328/205770_Dynamic_Exports_Compliance_Timeline.pdf

- Initially, *SAPN* provided a Development and Integration CSIP-AUS Server, enabling OEMs to test their CSIP-AUS Client devices. *SAPN* conducted certification of the equipment to verify CSIP-AUS compliance, including performing 'witnessing tests' of the CSIP-AUS DOE functionalities for new devices. The *Clean Energy Council (CEC)* maintains a central database of all inverter models certified by *SAPN*, serving as a key reference for industry stakeholders. This certification and listing process has subsequently been recognised in other jurisdictions, including *AusNet* in Victoria and *Synergy* in Western Australia.
- As more states rolled out DOEs, it became evident that a rigorous, nationally harmonised, certification process was required. Consequently, a centralised testing and certification process was established at the *Australian National University* to ensure interoperability across products from various OEMs and to manage compatibility of OEM products to various versions of CSIP-AUS.²⁵

Customer internet dependence and fail-safe operation: CSIP-AUS operation relies on the customer's internet connection for client devices to receive DOE setpoints. In the event of an internet outage, the inverter defaults to a low, static export limit. For example, *SAPN* considers a default export limit of 1.5 kW per phase, while *Energex* implements a forecasting-based fallback method during internet outages. While this default behaviour generally supports network continuity, it can disadvantage customers in areas with poor internet connectivity or those who intentionally disconnect their internet.

Lack of industry readiness: In the early stages of DOE deployment, solar installers' lack of familiarity with the new regulatory requirements and connection procedures led to non-compliant installations and approval delays. Incorrect installations, firmware updates, or system tampering may result in devices failing to apply DOEs as intended by the DNSP. The revised DER connection process therefore required installers to conduct a Dynamic Export capability test and correctly commission the inverter for CSIP-AUS communication.

- The adoption of DOEs requires coordinated education and training across the industry. Solar retailers needed to understand how DOEs work, and how to explain them effectively to customers, while solar installers required training on how to correctly commission DOE systems. PV inverter manufacturers also needed time to develop their CSIP-AUS clients, to conduct testing, and to obtain the required certification. Recognising these challenges, DNSPs understood that early and continuous engagement, supported by mandated training and practical tools, was critical. They acknowledged installers as the primary interface with the customers and invested heavily in training resources, support hotlines, and simplified online tools to ensure that the installer community could implement the new standards swiftly and precisely. For example, *SAPN* regularly conducts installer training sessions in collaboration with solar industry bodies and maintains a dedicated support team to assist with DOE installations, providing guidance to both manufacturers and customers.

Managing customer expectations: An inaccurate perception arose that Flexible Exports meant 'always 10 kW export capacity', because the *SAPN Flexible Exports for Solar PV Trial* indicated that customers could export at the full 10 kW limit for over 98% of the time. However, negative public commentary emerged from customers in highly congested areas who continued to experience frequent export limitations, despite these limits being substantially higher than the fixed 1.5 kW alternative.

²⁵ <https://arena.gov.au/projects/interoperability-steering-committee-and-csip-aus-testing-and-certification-development-study>

- It is important for DNSPs to clearly communicate to customers that DOEs represent a maximum export limit, not a guaranteed export value, and that actual export capacity is dynamic and location dependent. Customers should understand that DOEs are intended to enable greater overall solar hosting capacity across the network, rather than guarantee maximum exports for every customer at all times.
- To manage customer expectations, SAPN developed clear and proactive communication resources, such as eligibility checkers that display historical export limits, to help customers understand the trade-off between achieving higher overall export capacity and the potential for occasional curtailment due to failures of internet connectivity.

3.1.5. Recommendations for future users

- **Establish an interoperable communication standard**, such as IEEE 2030.5, to support consistent, secure, and scalable DER coordination, while avoiding reliance on ad hoc, vendor-specific solutions that may limit interoperability, increase integration complexity, and create long-term operational risks.
- **Invest in accurate network models**: Develop precise, interoperable medium voltage (MV) and low voltage (LV) network models for use in DOE calculations. The quality of these models directly affects how accurate and generous DOEs can be.
- **Build a robust failsafe mechanism**: Ensure that the communication standard incorporates a non-negotiable failsafe mechanism that automatically activates during communication loss or server failure, safeguarding continuity of grid operations under such conditions.
- **Follow a staged and coordinated rollout strategy**: A staged and coordinated approach supported by trials is a key lesson learnt to mitigate implementation risks. For example, the Victorian DOE rollout involved a compressed timeline, multiple CSIP-AUS server implementations across five DNSPs, and inconsistent installer portals and commissioning procedures, which led to an Emergency Backstop.²⁶

3.1.6. Steps for the full implementation

Standardise behind-the-meter (BTM) interoperability: While there are strong arguments that CSIP-AUS site-based control can provide better outcomes for customers, it introduces BTM interoperability challenges that remain unresolved in Australia. Under current arrangements, DNSPs send DOE setpoints to a site's designated master device without requiring coordination between that device and other on-site DERs, such as electric vehicle (EV) chargers or secondary batteries. Many BTM devices rely on non-standardised, proprietary communication protocols for DER-to-DER interactions, necessitating expensive, bespoke integrations. This lack of interoperability discourages the coordinated orchestration of BTM assets required to comply with site-scale DOE limits. Consequently, control is typically limited to a single device interfacing directly with the CSIP-AUS utility server, with little to no mediation of the aggregate site response. Standardising BTM communications within the site is therefore a useful prerequisite for enabling coordinated, multi-device control and for operationalising the inherent flexibility of DOEs across the distribution network. In this context, the upcoming AS 5438 interoperability standard is expected to significantly improve BTM interoperability.²⁷

²⁶ <https://cleanenergycouncil.org.au/getmedia/675c1d43-5ea7-4b43-81cb-966ce484f9d2/cec-submission-to-act-emergency-backstop-capability-consultation-paper.pdf>

²⁷ https://energysystems.anu.edu.au/files/2025-10/Peter%20Kilby_0.pdf

Flexible imports: Although flexible exports have demonstrated strong effectiveness, the full implementation of DOEs, including flexible imports (loads), remains constrained by several technical and regulatory barriers. Many flexible devices, such as EV chargers, air conditioners, and heat pumps, use proprietary communication protocols that impede coordination through central systems like a HEMS, thereby limiting the ability to deliver a coordinated, site-scale aggregate response. Moreover, while the curtailment of solar exports is now an established practice, constraining household electricity demand during peak periods raises consumer welfare concerns. Such demand-side constraints would therefore need to be supported by appropriate, cost-reflective retail incentives to ensure customers are adequately compensated for providing flexibility. Addressing these technical, regulatory, and social barriers is necessary to complete the full implementation of DOEs.

Coordination between network operators and market operators: The roles and technical intersections between network operators (who are responsible for setting DOE/technical limits) and market operators (who are responsible for pricing, dispatch, and market optimisation) are not well defined. Without clear boundaries and standardised interfaces, there is a risk of suboptimal DER operation and delays in implementing DOEs across multiple regions at full scale. Establishing such harmonised grid-market interfaces is therefore desirable to enable seamless, reliable, and large-scale DOE deployment. Efforts are currently underway to address this gap, including the *SAPN Market Active Solar Trial*²⁸ and the ongoing evolution of CSIP-AUS to incorporate dynamic pricing signals.

3.1.7. How to measure the success of the innovation

The *Flexible Exports for Solar PV Trial*, involving SAPN and AusNet, demonstrated the practical outcomes of DOEs, as presented in Figure 10.²⁹

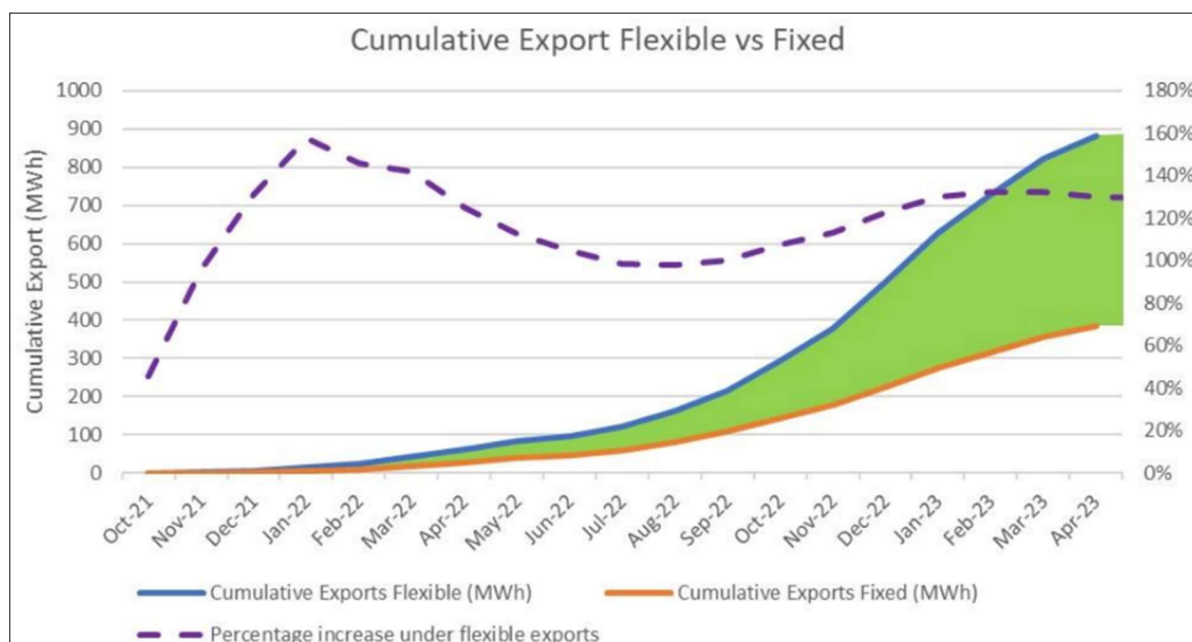


Figure 10. Cumulative energy export by Flexible vs Fixed (Static) Exports plan

²⁸ <https://arena.gov.au/projects/market-active-solar>

²⁹ <https://www.sapowernetworks.com.au/future-energy/past-projects-and-trials/flexible-exports-for-solar-pv-trial/>

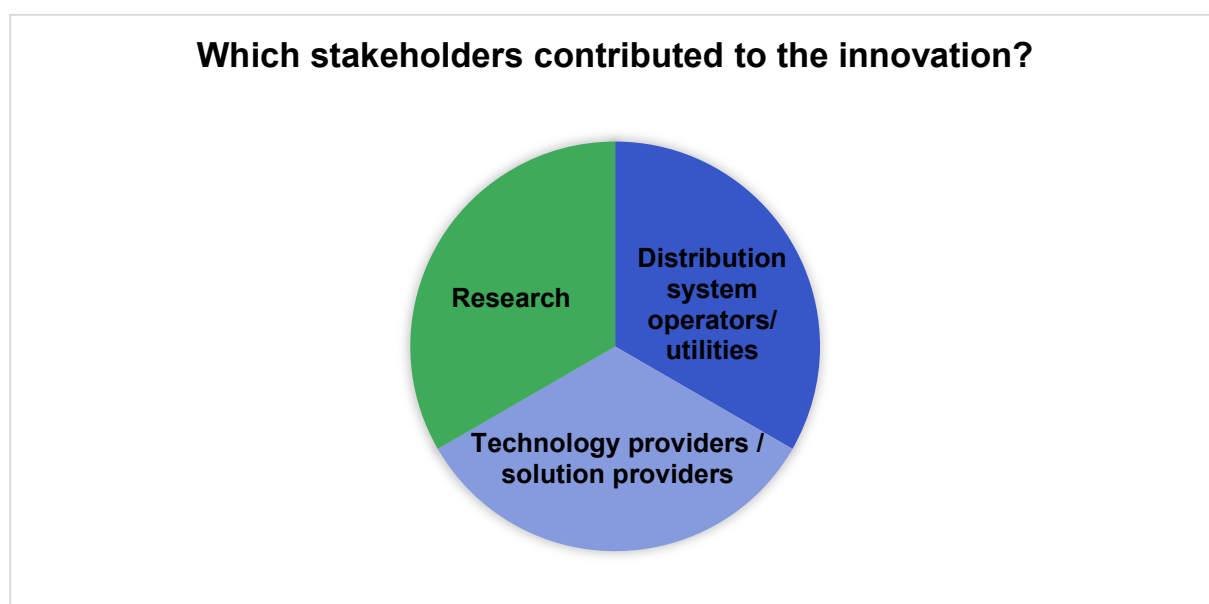
Trial outcomes by SAPN: The Flexible Export Plan offered by SAPN allowed customers the opportunity to export between 1.5 kW and 10 kW per phase, up to double the traditional, static 5 kW export limit. In the trial, export limits were governed primarily by overvoltage conditions. The trial was conducted on the hypothesis that, on average, customers would be able to export at 10 kW, or up to their inverter capacity, for 98% of the time. Analysis of the trial data demonstrates that this threshold was exceeded, with devices able to export at 10 kW, or up to their inverter capacity, for an average of 99.4% of the time. Under the previous static export model, these same customers were commonly limited to just 1.5 kW or even 0 kW.

The trial data also confirmed that DOEs could effectively double the renewable hosting capacity of existing network infrastructure without requiring any physical upgrades, such as new transformers or larger cables. Curtailment events were generally limited to instances where the flexible exports were activated in response to network contingencies (e.g. an outage of the Heywood Interconnector, which connects the states of South Australia and Victoria) or during periods of exceptionally high voltages driven by substantial PV output.

Figure 10 shows the total amount of energy released to the network by customers participating in the flexible exports plan. Flexible exports resulted in substantially greater renewable energy exports compared with a static (fixed) export plan. The green (solid) shaded area represents the unlocked network capacity for South Australians under a flexible system, resulting in a cumulative increase of approximately 500 MWh over the 18-month timeframe shown.

Trial outcomes by AusNet: AusNet provided participating customers with an average export capacity of approximately 2.93 kW during daylight hours through the flexible exports program. The majority of AusNet participants have inverter capacities of 5 kW or less. For these participants, an average export allowance of around 3 kW represents a meaningful incentive to participate in the flexible exports program when compared with the previously applied static export limit of zero.

3.1.8. Actors contributing to the innovation



Australia's innovation in DOEs, supported by the CSIP-AUS technical standard, has been driven by a collaborative effort involving multiple industry and research stakeholders. Key contributors include DNSPs, electric utilities, OEMs, aggregators, and consumers, alongside government bodies and academic institutions such as universities and research organisations. Together, these actors have contributed to the design, testing, standardisation, and validation of DOE concepts and their practical implementation within the Australian electricity system.

The ARENA's Distributed Energy Integration Program (DEIP) DOE Workstream Group acted as the primary platform for cross-industry collaboration, bringing together key stakeholders to shape the national approach to DOE deployment. The *Australian Energy Market Commission (AEMC)*, *AEMO*, and *Australian Energy Regulator (AER)* provided regulatory and market oversight. *Energy Consumers Australia (ECA)* and *Energy Networks Australia (ENA)* represented consumer and network operator interests. *The Australian National University (ANU)* and *CSIRO* played pivotal roles in research, modelling, and technical validation. *SAPN* provided industry leadership. To facilitate the transition from local trials to national interoperability, the *DEIP Interoperability Steering Committee (ISC)* established the *DER Integration API Technical Working Group (DERIAPITWG)* in 2019. *DERIAPITWG* leads and periodically forms sub-working groups to support the continued development of CSIP-AUS.

Did the roles of actors need to change through the process? Were new roles created?

The traditional role of DNSPs managing 'poles and wires', has evolved into a more operationally active DSO role. DNSPs are now responsible for matching DER access to available capacity by calculating time-varying DOEs.

Consumers have shifted from passive energy users to active power suppliers. By investing in DER, they now have the ability to sell power back to the grid and participate in markets.

Manufacturers of inverters and batteries have taken on an important new regulatory compliance responsibility. Under standards like CSIP-AUS, they are now responsible for ensuring their devices can securely communicate with network operators and can follow DOE setpoints in real-time.

Furthermore, new specialised roles have been created for technical validation. For example, the Australian National University has established a nationally harmonised testing and certification service to assess whether DER devices consistently follow the CSIP-AUS standard before being allowed to connect to the grid. Another new role has been the establishment of a national Public Key Infrastructure (PKI) authority, delivered through the National Energy PKI (NEPKI) established by the *Energy Networks Association (ENA)*. NEPKI serves as a central trust authority that issues digital certificates to DER, such as solar inverters, home batteries, and electric vehicles. By centralising this function, the industry avoids the inefficiency of individual DNSPs building their own bespoke security system.

3.1.9. Next steps

Enabling behind-the-meter (BTM) interoperability: Project CEVI (CSIP-AUS Electric Vehicle Integration), led by *CSIRO* and *Synergy*, expands *Synergy's* BTM interoperability framework, which is based on CSIP-AUS, to support communication between EVs and electric vehicle supply equipment (EVSE) using the open and widely adopted Open Charge Point Protocol (OCPP). As part of this effort, *CSIRO* is developing a CSIP-OCPP bridge to enable seamless, standards-based communication between EVSE and *Synergy's* systems for remote management.

Enhancing CSIP-AUS scalability: CSIP-AUS is now being deployed at a scale far beyond what the underlying CSIP/IEEE 2030.5 standards were originally designed to handle. While IEEE 2030.5 was intended for communication with individual or small numbers of DERs, CSIP-AUS is now being applied across thousands of devices at multiple sites, each potentially generating high-frequency monitoring and DOE update data. This raises concerns about communication network load, server performance, and latency, given the need for robust coordination mechanisms to ensure reliable operation. Ensuring that CSIP-AUS can maintain responsiveness at such large scales will be necessary for its success in supporting widespread DER integration.

Improving DOE determination: As DOEs scale to millions of devices, the mathematical models used to calculate them face a fidelity challenge. Presently, DOEs are typically calculated at nodes in the LV network at the scale of individual neighbourhoods. However, as multiple neighbourhoods implement DOEs simultaneously, their collective impact on HV networks becomes increasingly difficult to predict. Full scale implementation is further constrained in regions without full smart meter coverage. In the absence of real-time data from all households, networks must apply larger uncertainty buffers, which can restrict customer exports compared to when comprehensive information is available. It is important to develop advanced solutions for accurately forecasting the active and reactive power of small groups of residential customers, because inaccurate forecasts can result in erroneous DOEs, possibly causing voltage excursions or thermal damage to transformers.

Managing cybersecurity risks: Coordinating millions of inverters, EVs, and batteries via cloud-based platforms creates a substantial cybersecurity attack surface. A single compromise of a major OEM's platform could possibly induce synchronised fluctuations in power demand or generation, threatening the stability of the NEM. Managing digital identities and security certificates for millions of devices requires a robust, national-scale cybersecurity strategy, which remains challenging for many smaller actors to implement effectively.

Any other comment you would like to make to help others implement such changes?

DOEs offer a transformative pathway for distribution grids to move from blunt, static export limits to data-driven, dynamic management of two-way power flows within voltage and thermal constraints. Australia's experience shows that successful DOE implementation depends on open standards like CSIP-AUS, which prevents proprietary "walled gardens" and support transparent, fair and interoperable capacity-sharing. Ultimately, DOEs could provide a scalable, future-proof solution for nations seeking to decarbonise while maintaining distribution grid stability and long-term energy affordability for all consumers.

3.2. Austria (KNG): Smart meter-based network planning tool

Authors: Susanne Windischberger and Helfried Brunner (AIT-Austria Institute of Technology GmbH)

Contributing author: Stephan Brandl (KNG-Kärnten Netz GmbH)

The presented tool is used in all phases of long-term planning. It includes functionalities to assess future need of grid enforcement as well as operation of the current grid.

Phases addressed: strategic foresight, strategic direction, development options, assessment and decision, implementation

3.2.1. The start

Austria's electricity sector is facing a lasting transformation with the adoption of the **new Electricity Industry Act** (EIWG) opening the door to the important use of metering data from automated metering systems (Smart Meters).³⁰ This development marks a paradigm shift from decisions based on historical assumptions to data-driven foundations. In the future, metering points will yield valuable insights for planning, operation, and asset management. The EIWG, adopted end of 2025, significantly strengthens the role of intelligent metering devices. It establishes a **modern, data-based framework for grid operation**, market processes, and customer benefits. Instead of isolated spot measurements, grid operators, who are in charge of the metering services in Austria, now have access to continuously collected, virtually comprehensive power and voltage data. The recorded 15-minute interval values can be used in a wide range of ways: for example, for load and generation forecasting, optimising grid operation, targeted grid expansion, balancing group management, and for flexibility and aggregation services (EIWG § 57). In addition, grid operators are given the option to capture additional operational parameters, such as voltage, reactive power, or harmonics directly via smart meters (EIWG § 57(4)). This facilitates the integration of PV systems, heat pumps, and electric mobility. For the first time, the data basis enables a timely, precise assessment of grid conditions reaching down into the low-voltage level—thereby providing a robust foundation for data-driven decisions in planning and operations.

The presented project was initiated by the management of an Austrian distribution system operator (Kärnten Netz GmbH - KNG) located in the south of Austria, and a technology provider (Siemens AG Österreich). They decided to join forces to pursue an innovation project enabling distribution grid monitoring.

The aging and deteriorating condition of grid operating assets as well as the increasing number of photovoltaics in private households and small industry has created an escalating need for grid capacity. Furthermore, there was an increasing need for grid reinforcements driven by new applications based on electrical energy, decentralised generation plants, and storage systems. In just a few years, the low-voltage level has evolved from an energy sink into a large, distributed energy source. This causes high demands on grid infrastructure at the medium- and low-voltage levels, especially during periods of strong solar irradiation. This development requires distribution system operators such as KNG to adopt innovative approaches across the entire asset management lifecycle (planning, operation, maintenance, etc.).

The aim of the project was to enhance the existing asset management of KNG by a distribution grid monitoring tool. Previously, KNG used a self-created asset management tool which required professionalisation and enhancement.

³⁰ Bundesgesetz zur Regelung der Elektrizitätswirtschaft (Elektrizitätswirtschaftsgesetz – EIWG) StF: BGBl. I Nr. 91/2025

3.2.2. The innovation

The innovation fosters an optimisation of network planning and operational portfolio management based on Smart Meter voltage values:

The tool **visualises and analyses the voltage values of all smart meters** in the DSO's supply region to **identify critical network segments** and meet the requirements of ISO 55001.³¹

The tool was designed to continuously identify and assess asset-related risks from smart meter data only. The innovation of this tool is the use of smart meter data to monitor the distribution grid and only from that data to assess the state of the grid with a spatial resolution of smart meter scale. The assessment of the data is done via a **Grid Impact Score**, which varies between 1 and 10, where higher values mean higher need for action.³² This grid impact score offers a comprehensive assessment of the grid safety limits and can be calculated using historical data, projected data considering future penetration rates of DER and projected data considering future penetration rates of DER combined with potential mitigation measures.

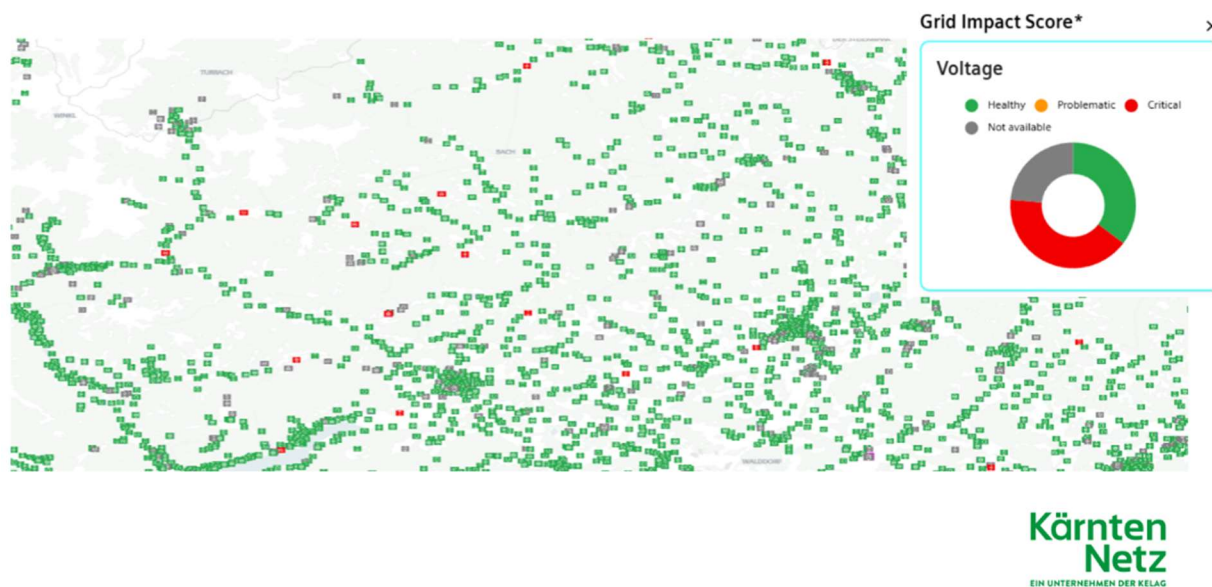


Figure 11. Grid Impact Score in the low voltage grid of the utility KNG

Figure 12 shows a case where there are still free capacities for decentralised energy resources. No immediate measure is necessary in this case. In a similar way network measurements can be assessed and their effectivity increased.

³¹ ISO, ISO 55000/55001/55002 – Asset Management Standards, International Organisation for Standardisation, 2014.

³² M. Metzger, at all, "Introducing the grid impact score: an indicator for DER impact on present and future grid states," *CIREN 2024 Vienna Workshop*, Vienna, Austria, 2024, pp. 891-895

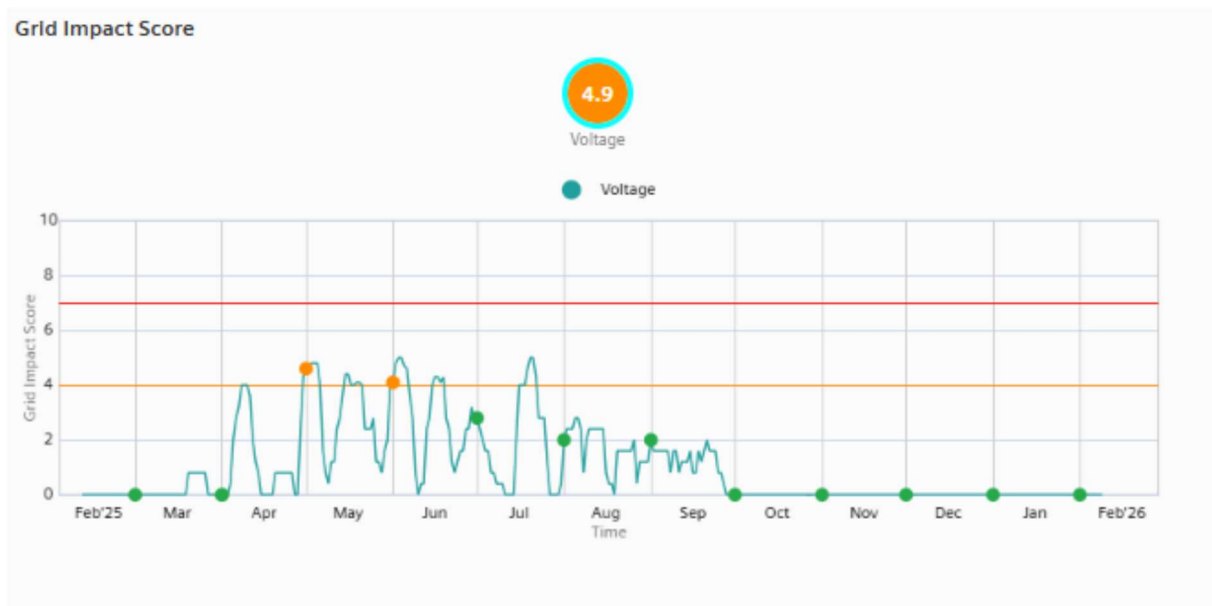


Figure 12. Grid Impact Score at one grid point

The tool provides a clear visibility into the **operating status of the network** at the lower voltage levels. With the knowledge measures for grid reinforcement can be prioritised and planned in a transparent and clear way according to the criticality they solve. Such measures include traditional grid reinforcement, series voltage regulator, and controllable distribution-grid transformers.

Furthermore, the tool can **assess the efficiency of activities** in achieving corporate objectives and legal requirements regarding resource use. Figure 13 shows the voltage level and Figure 14, the Grid Impact Score before and after a measure has been taken. This clearly shows that the grid was already at its limit before and is in stable operation after the measure has been taken.

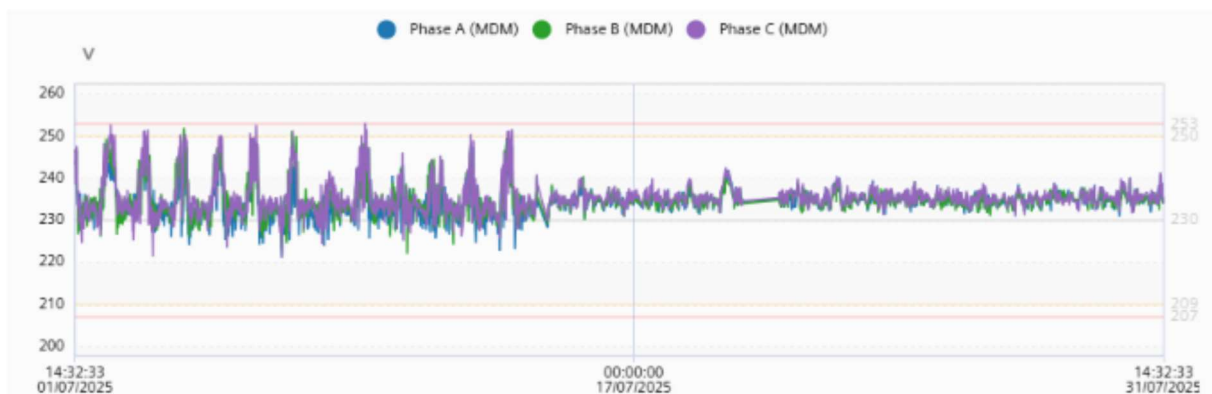


Figure 13. Voltage level before and after taking a measure

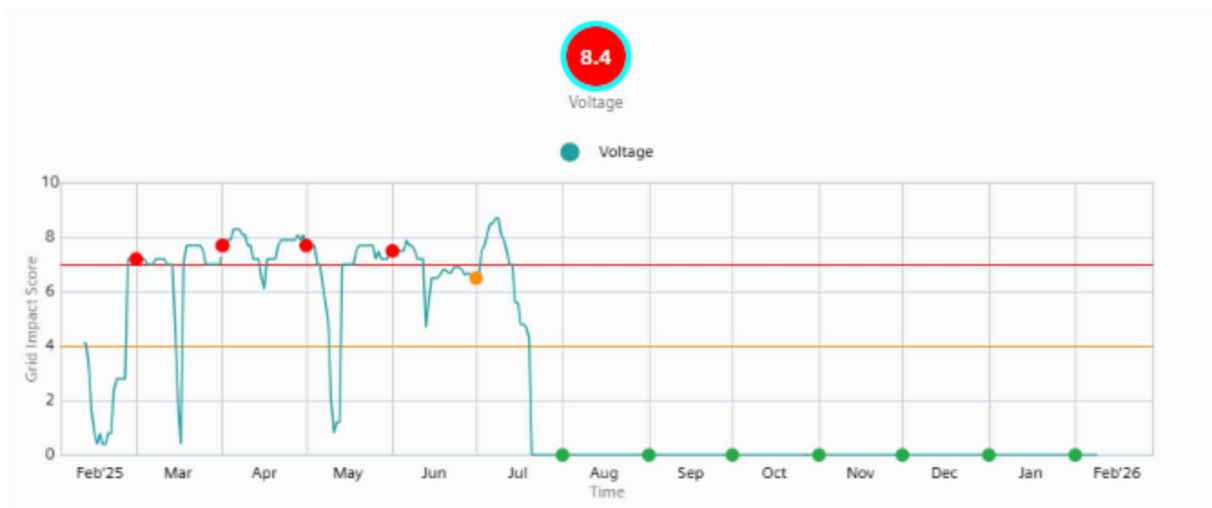


Figure 14. Grid Impact Score before and after the measure has been taken

Using the tool also ensures that all decisions are made transparently and based on risk, aligned with corporate values. Additionally, it aims to foster continuous improvement by evaluating the success of activities and collaboratively deriving and implementing improvement measures. After completion of the measures, the tool is used to monitor and verify the effectiveness of the measures.

3.2.3. The application

The tool is already in use at the Austrian DSO and further applications at other DSOs are planned by the technology provider.

3.2.4. The challenges

At the beginning of the project the regulation in Austria did not allow distribution system operators to use all available data from smart meters for network planning and operation. The electricity industry enables this possibility from the end of 2025. Thus, better analyses are possible now, utilising active power (P) and reactive power (Q).

3.2.5. Recommendations for future users

A great success factor for the implementation of the tool was strong support by the management and an open-minded attitude on the technician level.

For the use by other DSOs some adaptations will be necessary. The technology provider is working on commercialising and thus scaling up the use of the tool.

3.2.6. Steps for the full implementation

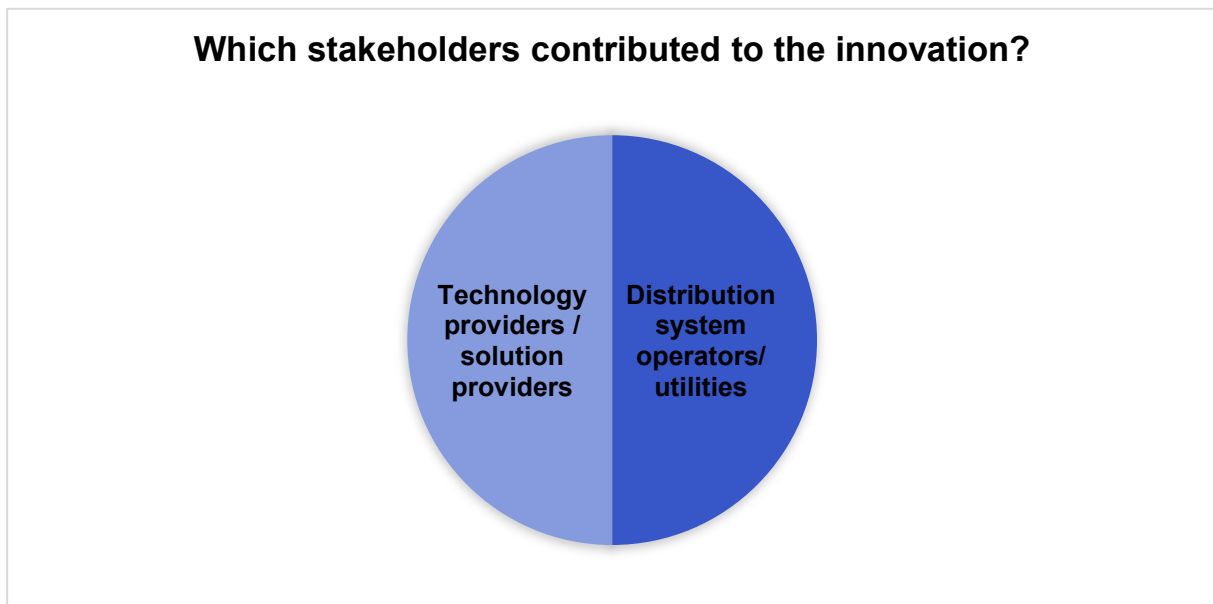
Today, the tool is primarily used for monitoring the low-voltage grid, planning grid expansion projects based on the Grid Impact Score and assessing the effectiveness of grid measures.

Through retrospective analysis the tool will also offer pre-operative analysis and provide actionable options for managing future events.

3.2.7. How to measure the success of the innovation

The innovation is already in use at the DSO and further applications are planned by the technology provider.

3.2.8. Actors contributing to the innovation



3.2.9. Next steps

The established database is suitable for achieving further improvements to the Grid Impact Score by linking different measured values. In addition, the information provides the foundation for elevating internal processes, such as connection assessment and risk-based grid planning, to a new level, thereby creating additional value through straightforward scalability.

3.3. Austria 567

Author: Helfried Brunner (AIT Austria Institute of Technology GmbH)

Contributing authors: Clemens Korner and Roman Schwalbe (AIT Austrian Institute of Technology)

Phases addressed: assessment and decision

3.3.1. The start

Grid planning departments of individual distribution system operators (DSOs) have existing processes for short, medium and long-term network planning. The short-term network planning is usually project or event triggered. This involves, amongst other things, specific inquiries on connecting new customers or generation units or maintaining the existing grids. In long-term strategic network planning, mainly regional developments are considered, such as the emergence of an industrial area, business park, the expected connection of renewable generation plants or population growth in the supply area. In most cases, historical growth figures are used for future developments and general statements about expected network investments in the entire supply area are derived.

At present, however, it is only possible for DSOs to carry out comprehensive analyses of their entire supply infrastructure to a limited extent and for several technological expansion scenarios. There is a lack of technology (availability of network data in electronic form, computing capacity, functionalities of the network simulation software), of the methods for transferring the technology scenarios to the network infrastructure, and/or of the availability of skilled personnel.

3.3.2. The innovation

Nevertheless, distribution grid planners need enhanced methods and approaches to efficiently evaluate the effects of various developments on their entire low and medium voltage grid. The central challenge for full supply area power system simulations arises from the large number of possible scenarios that are to be applied to a high number of networks with different technology options.

In this project (Figure 15), the Austrian Institute of Technology, together with three Austrian DSOs, developed a method enabling a quantitative survey of the area effectiveness of future medium and long-term grid related measures (network restructuring, operational strategies) in the entire medium- and low-voltage infrastructure of a DSO (Figure 16).

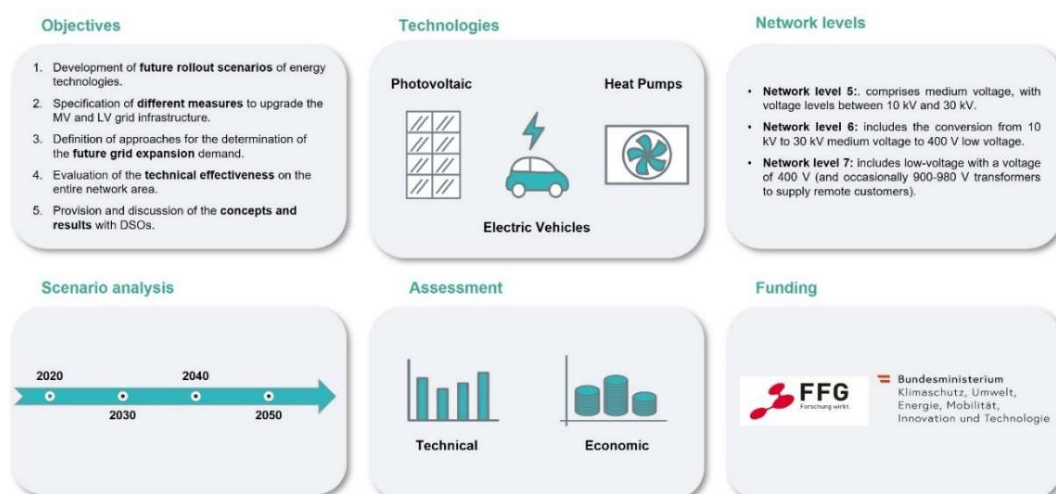


Figure 15. Project overview

The developed framework provides a simulation environment capable of automatically calculating and comparing the impacts of various future scenarios and planning strategies. Its functionality is divided into three core categories: regionalisation, grid simulations, and analysis and reporting.

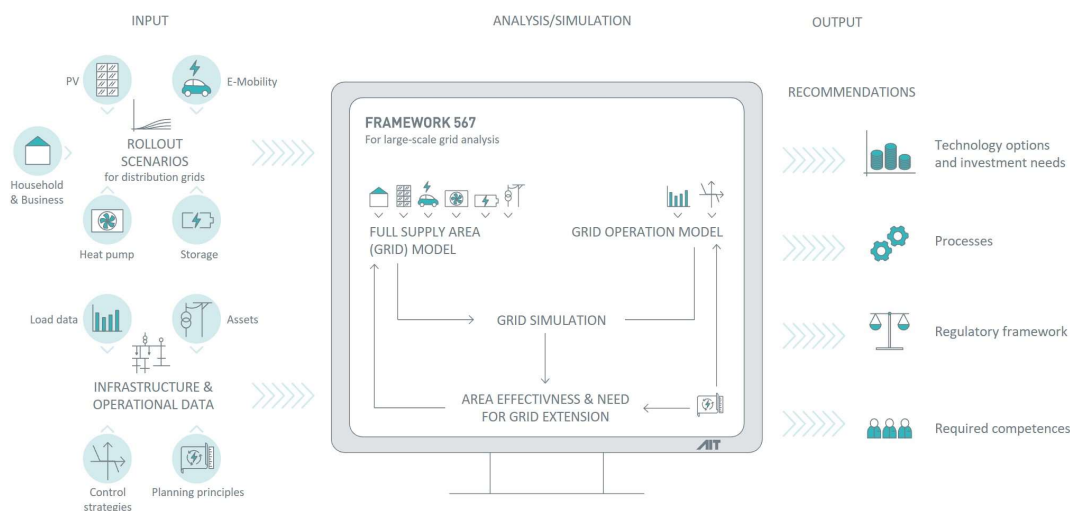


Figure 16. Simulation framework

Regionalisation³³: The goal of regionalisation is to realistically distribute future load and generation units across different areas of the grid. A crucial aspect of this process is determining the timeline and sequence in which these elements are deployed within the supply area. The approach provides scientifically based, regionalised forecasts of future demand scenarios for electromobility, heat pumps incl. general load increase and generation scenarios for photovoltaics. For details see ^{34, 35, 36} and Figure 18.

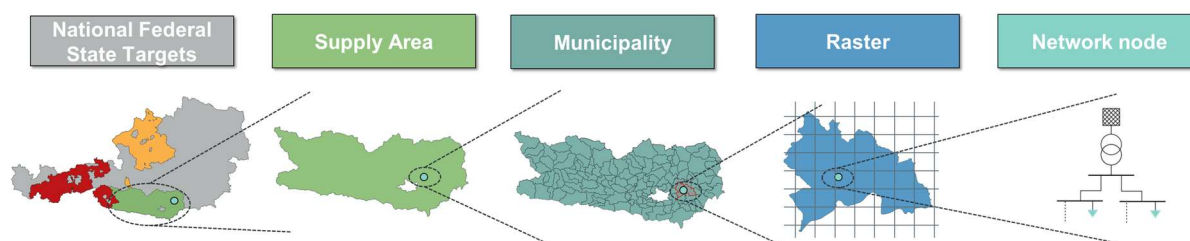


Figure 17. Regionalisation methodology

Regionalisation is conducted using a top-down approach, starting from national or state-level goals and progressively narrowing down to supply areas, municipalities, 250m x 250m raster cells, and finally, individual metering points within the grid. Georeferenced network models are essential for this process, enabling accurate consideration of local conditions at metering points and their intersection with geographic information system (GIS) layers.

³³ Barbara Herndler et.al., “Regionalised approach to heat pump allocation and its impact on LV network reinforcement requirements”, CIRED 2023, Rome, 12-15 June 2023.

³⁴ Helfried Brunner et.al., “Methods and future scenarios for strategic grid development of full low and medium voltage DSO supply areas”, CIRED 2023, Rome, 12-15 June 2023.

³⁵ Paul Zehetbauer et.al., “Data driven photovoltaic regionalisation approach for distribution system operator supply areas”, CIRED 2023, Rome, 12-15 June 2023.

³⁶ Barbara Herndler et.al., “Impact of EV regionalisation on network reinforcement requirements”, CIRED 2023, Rome, 12-15 June 2023.

Grid simulations: Grid calculations start with the import of georeferenced grid models, which are available in various formats, into the simulation environment. Import and conversion processes are automated using scripts written in the programming language Python. Since the simulation environment relies on PowerFactory for load flow calculations, the grid model conversion is handled via PowerFactory’s Python application programming interface (API).

Next, load flow scenarios, such as “high-load and no-infeed” and “high-infeed and low-load” are defined. These scenarios are commonly used in DSO network planning. These scenarios are used to calculate reference load flows, to validate the created models and ensure that the simulation environments results align with those of the original models.

A key aspect of the grid simulations is the parametrisation of the network reinforcement algorithm. This involves defining both the conditions under which grid reinforcement is triggered and the DOS specific grid reinforcement strategy and asset base itself. For example, loading limits for grid elements can be set, with reinforcement being triggered once these limits are exceeded. Additionally, it is crucial to determine the desired outcome of the reinforcement, with the planning horizon playing a key role. The grid reinforcement serves as a base scenario (including related costs). In a next step, grid reinforcement can be compared with different measures for increasing grid capacity (Figure 17) taking into consideration both the effect on grid capacity and related costs. In addition, the different measures can be compared to each other.³⁷

Measures to avoid voltage problems		Measures to avoid thermal overloading	
MV	LV	MV	LV
Increasing system voltage	Building new secondary substations	Increasing system voltage	Building new secondary substations
Reduction of intermediate voltage levels	Manual transformer stepping	Reduction of intermediate voltage levels	Manual transformer stepping
Reactive power compensation	950V-solutions	Reactive power compensation	950V-solutions
Primary substation – current compounding	OLTC (+voltage control strategies)	Primary substation – current compounding	OLTC (+voltage control strategies)
Voltage drop compensator		Voltage drop compensator	
Reactive power control		Reactive power control	
Active power control (P(U), PV $0.7 \cdot P_{nom}$, EV $0.5 \cdot P_{nom}$)		Active power control (P(U), PV $0.7 \cdot P_{nom}$, EV $0.5 \cdot P_{nom}$)	

Figure 18. Introduced measures to increase grid capacity

Analysis and reporting: All relevant information and results from the network reinforcement are stored in a database, which is optimised for online analytical processing (OLAP) and enables efficient analysis of large data volumes. Before generating reports, a post-processing step is performed to extend and aggregate existing data in the database as needed. For example, the database stores details such as the start and end type of each reinforced line, as well as the date of reinforcement.

During the analysis phase, the costs associated with these reinforcements are calculated, stored, and subsequently aggregated. This allows for easy querying of material costs for cable reinforcement in a specific grid and year. After the post-processing step, various simulation runs can be compared.

³⁷ Clemens Korner et.al., “Influences of different planning horizons on strategic grid planning in low-voltage grids”, CIRED 2025, Geneva, 16-19 June 2025.

Interactive reports are automatically generated, and results can be analysed in dashboards. This functionality enables, for example, evaluating the impact of individual measures on grid expansion costs (reference scenario) based on individual regionalisation scenarios (Figure 19), such as:

- “Conventional” grid reinforcement (reference scenario)
- OLTCs (on-load tap changers), SVRs (series voltage regulators)
- Primary substation current compounding
- Increasing the operating voltage
- Active and reactive power control, etc.

Measure	Scope (LV,MV)	Stakeholder involved			Cost damping (%) related to total costs (LV+MV) of the reference scenario	
		DSO	Customer	Regulator	2030	2050
OLTC and LV-SVR as a supplement to pure line reinforcement for voltage problems	LV	×			5 – 10 	5 – 10
Prim. Substation-Compounding Active current-dependent voltage regulation in the primary substation	MV	×			10 – 20 	5 – 15
MV-SVR as a supplement to pure line reinforcement for voltage problems	MV	×			5 – 15 	5 – 15
PV-feed in limitation 70% of the module output correspond to max. 3% reduction in the feed-in p.a., use of surplus electricity for customer possible	LV+MV		×	×	5 – 15 	10 – 15
PV-Q(U) Costs of reactive power generation at upstream grid levels not taken into account	LV+MV	×	×		10 – 30 	20 – 25
EV peak time throttling Temporary charging power throttling of PRIVATE electric vehicle charging to 50% during peak load situations in the grid	LV+MV	×	×	×	5 – 25 	5 – 15

Figure 19. Cost damping factors for different measures to extend grid capacity

In addition, the framework allows analysis of the effects of different planning horizons and different interest rates (Figure 20).

- *No Forecast (FC)*: When a grid needs reinforcement, reinforce it for the here and now
- *Buffer*: Reinforce grids with additional capacity buffers (voltage and asset loading)
- *FC 5 years (yr)*: Reinforce a grid for the projected load and generation situation in 5 years
- *FC 10 yr*: Inclusion of a forecast horizon of 10 years
- *FC 2050*: As soon as a grid needs upgrading, it is reinforced for the year 2050.



Figure 20. Influence of different planning horizons and interest rates on the investment costs

Beside the evaluation of concrete technology options and investment needs, the solutions enable the DSO to analyse related planning processes and identify required competences as well as improvements of future regulatory frameworks (Table 1).

	Output	Description
	Technology options and investment needs	The results enable network operators to conduct a long-term, strategic analysis of different technology options as a basis for future, comprehensive investment decisions.
	Processes	Necessary adaptations to the existing planning principles and processes of distribution network operators.
	Required competences	Identification of necessary skills and timely competence development to be prepared for future challenges.
	Regulatory framework	Analysing the spatial effectiveness of different measures can serve as a sound basis for discussing future regulatory frameworks.

Table 1. P567 output

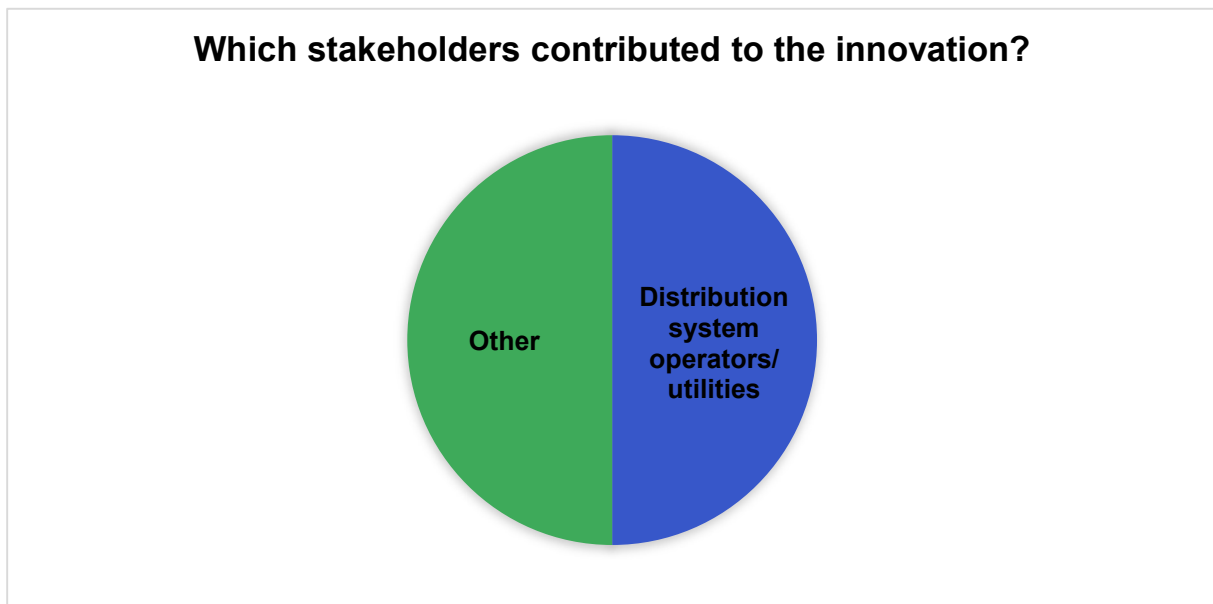
3.3.3. The application

The methodology is applied with several DSOs in Austria.

3.3.4. How to measure the success of the innovation

The P567 framework and the analysis performed by the researchers have been well received by the involved grid operations. The CEOs used the results from the pilot framework as bases and decision support in budget and investment negotiations with their shareholders.

3.3.5. Actors contributing to the innovation



Stakeholders involved in the development process included researchers, grid planners, and CEOs from the involved DSOs, which took into consideration national and regional renewable objectives as well as national and regional regulatory frameworks. In course of the project execution, the intermediate results were discussed with representatives from other DSOs, via Österreichs Energie, which is the Austrian Association of Electricity Companies. In the final phase, representatives from the Austrian regulatory authority for electricity and gas have been invited to discuss the results and conclusions.

3.3.6. Next steps

The framework is still hosted by the RTO Austrian Institute of Technology enabling the Institute to provide analyses and services to network operators. In beginning of 2026, an initiative has been started to further enhance the approach towards full automation supported by different AI approaches and to provide the solution as software as a service (SaaS).

3.4. Canada: Large-scale fully integrated net-zero energy community

Authors: Anjali Wadhera and Steven Wong (Natural Resources Canada's CannmetENERGY in Varennes)

Contributing author: Gary Stevens (s2e Technologies)

Phases addressed: strategic direction, implementation

3.4.1. The start

West 5, an ongoing project initiated by proponent Sifton Properties (developer) and other partners including s2e Technologies (solutions provider) and London Hydro (local distribution company), aims to demonstrate Canada's first large-scale fully integrated net-zero energy community and show that that net-zero is feasible at the community level.³⁸

Along the way to achieving its goal of net zero, the project is showcasing new technologies while integrating forward thinking community design encompassing the best in environmental stewardship and societal/living concepts. The community includes living spaces for all generations (including retirement) with retail and office locations.

The net-zero community hosts a DC microgrid with connected battery and PV systems (rooftop PV (460kW+), BIPV (55kW+), PV parkade (265kW)) that will support the community and its connecting utility, London Hydro. Other features include green roofs, view dynamic glass to automatically control sunlight in the space, an air source heat pump with variable refrigerant flow, automated LEDs, and rainwater harvesting. For some residential spaces, drain water heat recovery and triple-pane low-e low solar heat gain coefficient windows are being deployed. There is also the EVE Park testing the first vertical lift parking garage supporting community-shared electric vehicles.³⁹

The following stakeholders were involved in the development:

- S2e Technologies is the visionary and driver behind this project. It led, coordinated, and supported community design, technology (incl. microgrid) research and feasibility studies, and building. Additionally, it was responsible for the EVE Park location within the community.⁴⁰
- London Hydro is the distribution utility who will manage and operate the microgrid and is administering electricity billing. EVE Park and Helio (rental apartment building) use third party billing for the residential customers; the other town homes have individual London Hydro meters.
- Sifton Properties Ltd, the developer, helped develop master plans for the community.
- Ontario Energy Board, the regulator, and the Ontario government had to revise regulations and laws respectively to allow for community virtual net metering (CNM), with Sifton Properties at West Five becoming the first CNM pilot.
- The University of Western and University of Waterloo contributed to research activities.
- Natural Resources Canada provided funding to advance low technology readiness level innovations.

³⁸ <https://natural-resources.canada.ca/funding-partnerships/net-zero-energy-mixed-use-high-rise-building>; <https://west5.ca>

³⁹ <https://www.evepark.ca/blog/canada-funds-worlds-first-fully-automated-pick-up-parking-system>

⁴⁰ <https://www.evepark.ca/home>

3.4.2. The innovation

The regulator, the Ontario Energy Board, released community net metering regulation allowing renewable energy projects in the community development to allow **electricity generation credits across multiple facilities**. This agreement is not a standard program offering but must adhere to the following qualifications:

1. made between the utility and generator
2. total generation or battery capacity needs to be below 10 MW
3. billed as a single customer
4. needs to be listed in Schedule 1 of O. Reg. 679/21: COMMUNITY NET METERING PROJECTS.

Terminology and definitions were developed to help establish processes.

The distribution utility, London Hydro, had to re-design metering and accounts with units, buildings and campus to properly allocate electricity bill credits with community net metering (Figure 21 and Figure 22).

CNM Billing Example – Generate a Credit

- Assume three buildings:

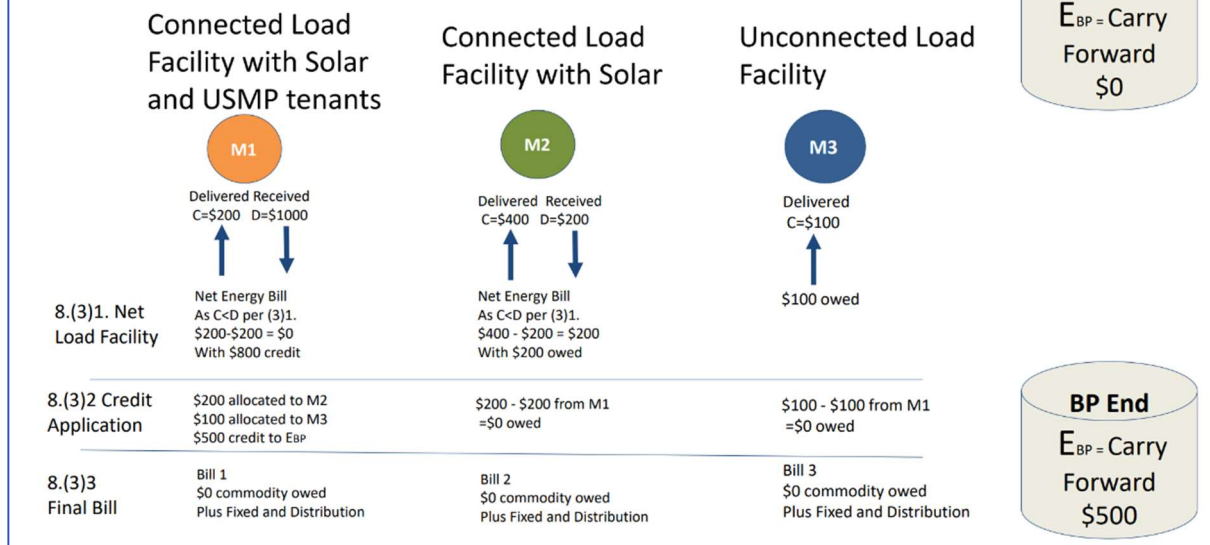


Figure 21. Example of a credit generation process

CNM Billing Example – Consume a Credit

- Assume three buildings:

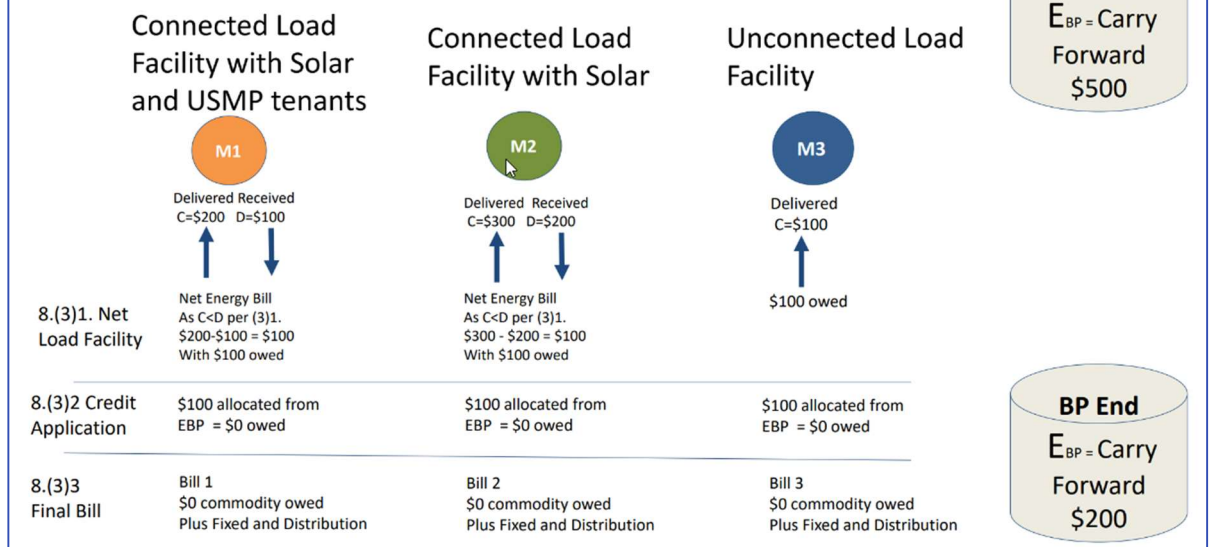


Figure 22. Example of a credit consumption process

3.4.3. The application

The new regulation enabled community net metering, but only for this one project in the Province of Ontario, Canada. It is expected that regulations will evolve, reflecting lessons learned, being opened to new entrants.

3.4.4. The challenges

Typically, current procedures are not designed to effectively support new innovation. Organisations tend to adapt procedures from different contexts that do not necessarily align with the needs of the innovation to be deployed. Some specific examples for this project include

(1) spending patterns needed to be reviewed by regulators regarding investments the distribution utility need for community net metering, and (2) zoning conflicts with infrastructure and deploying the technologies needed. Solutions involved being able to adapt and respond to setbacks with engagements to arrive at a solution with agreement from all stakeholders.

Another challenge was that no regulatory structure was in place for community net metering; electricity bill credits could not extend beyond the meter to which the DG was attached, e.g., from one metered building to another metered building of the same owner. Without such, net-zero was economically infeasible.

Dealing with conservative and redundant systems that prohibit innovation also proved challenging. Innovation needs to be part of the culture among stakeholders such as distribution utilities, regulators and municipalities. The concept of building a net-zero energy community versus building a conventional community required significant consultations and education to ensure the ideas were well communicated and understood. Substantial time was invested throughout to keep pushing for the innovation to become a reality.

There needs to be reassurance given to builders worried about delays and receiving returns on the investments they have made. Advancing innovation requires capital and ensuring investor buy-in exists is critical to sustaining projects.

Lack of standardisation was a key challenge in implementing a DC microgrid to sustain critical loads. This required working with industry partners to establish products and procedures that enabled deploying such systems.

3.4.5. Recommendations for future users

- There is a need for regulatory sandboxes to innovate to allow for new procedures, systems or projects to be a possibility.
- It is important to know the ownership of the electrical asset in development (utility, developer, future owners, end customers) and how that plays a role in the community net metering design.
- The utility needs to establish its procedures and terminology for the development and the associated rate classifications for metering purposes, along with any additional changes needed to uphold this structure.
- Consider a phased approach to expand generation to reduce spillage to the grid which can lead to significant complications.
- Consider the design of the electricity bill credit being given to customers. Does it make more sense to have a rebate or credit? Should it depend on the rate or energy?

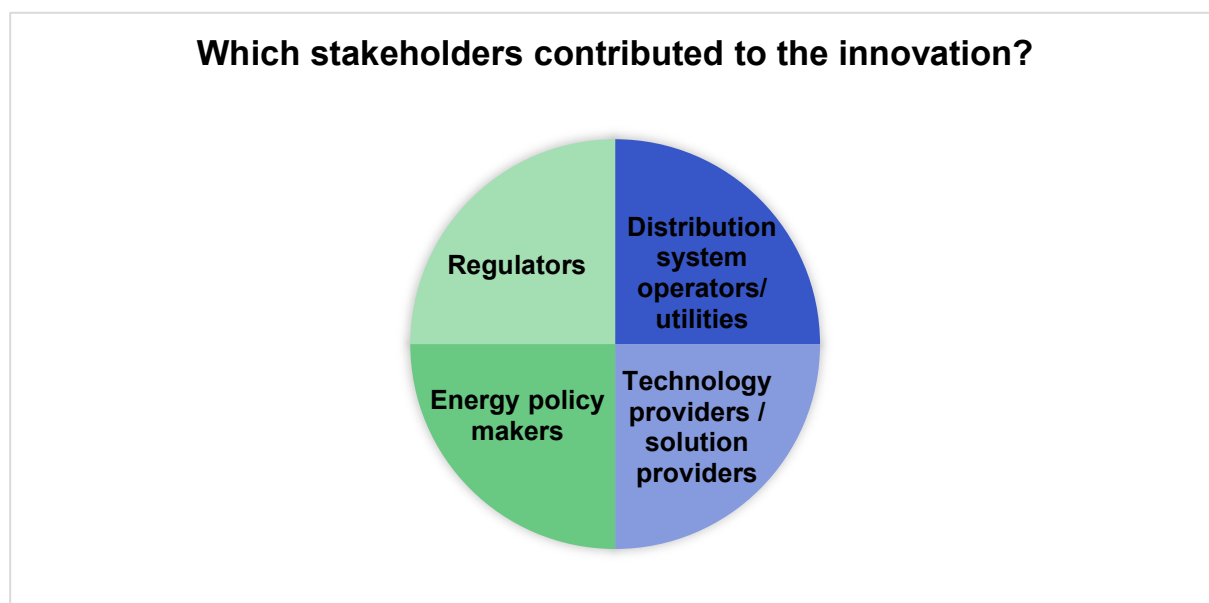
3.4.6. Steps for the full implementation

This use case has carved its space in the regulations, but regulations need to be re-worked to allow for other organisations to follow suit. Other distribution utilities may face similar issues related to metering structure and recommendations to be worked out, as described above.

3.4.7. How to measure the success of the innovation

The established new regulation with the Ontario Energy Board is proof that this innovation can be considered a successful example of community net metering.

3.4.8. Actors contributing to the innovation



Roles of actors which change throughout the process

The project lead, s2e, played an important advocacy role in the benefits of community net metering implementation. Negotiations were also needed between the regulator and provincial government. It was necessary for the project lead to address gaps in standard development related to DC microgrids.

The interaction between the actors changed as follows:

New regulation needed to be created so that more community members could benefit from the renewable energy being generated. Innovative interaction between DG owners and customers in the form of revenue was created, and the way the LDC metered the generation with bidirectional interval metering and appropriate rate classification for load accounts was established. The LDC is invoicing each facility for load and generation, with generation billing credit applied on their bill along with loss adjustment factor for energy delivered (but not received).

3.4.9. Next steps

The upcoming plans for the innovation are related to several technology demonstrations within the NZEC. A DC microgrid is to be deployed with a battery system providing services to the distribution utility, London Hydro. The microgrid will also be showcasing seamless operation between islanding and grid-connected modes.

Challenges in scaling up:

Regulations need to evolve, in the pilot phase before evolving to better adapt to Ontario's needs.

3.5. Denmark: Toolchain for predictive asset management

Author: Hamid Reza Shaker (SDU Centre for Energy Informatics, University of Southern Denmark)

Contributing authors: Hamid Mirshekali and Mohammad Reza Shadi (SDU Centre for Energy Informatics, University of Southern Denmark)

Phase addressed: development options

3.5.1. The start

The initiative started when Danish DSOs and the research team at the University of Southern Denmark realised that a huge amount of existing grid data (GIS, SCADA, asset registers and smart-meter data) was not being used for systematic maintenance and reinvestment planning. Ageing underground cables, increasing demand and limited CAPEX meant that traditional approaches – reactive repairs after failures or simple age-based replacement – were no longer sufficient to maintain reliability and keep costs under control.

The change was initiated through an EUDP project on “Leveraging Smart Meter Data to Optimize Grid Investments”, where the research team set out to move from reactive and preventive maintenance towards predictive and prescriptive asset management based purely on data that DSOs already have in-house, without installing new hardware.

The concrete challenge was: given a large fleet of ageing medium-voltage cables and fixed annual budgets, which cables should be replaced, repaired or left in service each year to minimize outage risk and socio-economic cost while meeting reliability targets (SAIDI/SAIFI)? Predictive Asset Management Smart Energy Network (PAMSEN) was developed as the predictive asset management tool that addresses this use case by turning failure-risk estimates into multi-year, budget-constrained renewal plans and visual risk maps that DSOs can use directly in their investment and maintenance planning.

The management team supported the effort in initiating and driving the innovation.

3.5.2. The innovation

In this project a **complete, software-based toolchain for predictive asset management**, centered around the PAMSEN toolset was developed. On the analytics side, the team created a Neural Weibull Proportional Hazard (NWPH) modelling pipeline that estimates cable-level hazard, reliability and fault vulnerability from GIS, asset and failure-history data. The model is censoring- and truncation-aware and is embedded in a Bayesian nested Monte Carlo simulator, producing risk-aware rankings and uncertainty measures for every underground cable.

These risk metrics feed a new reliability-aware multi-objective planning process. The research team formulated cable renewal planning as a mixed-integer, multi-objective optimisation problem that, under annual budget constraints, minimises expected outage costs and interruption indices (SAIFI/SAIDI/ASIDI) while maximising the number of cables renewed. The epsilon-constraint method generates a Pareto set of renewal plans together with expected cost and reliability impacts, allowing DSOs to choose the plan that best fits their policies and budget.

All of this is implemented and operationalised in the PAMSEN tool. PAMSEN ingests standard DSO datasets (asset registers, cable geometries, and NWPH-derived failure probabilities), performs automatic data validation and harmonisation, and then runs multi-year, budget-constrained optimisation to decide, for each cable and each year, whether to “Replace”, “Repair” or “Do nothing”.

Results are exposed through:

- an Optimisation module with user-defined horizons, yearly budgets and repair-to-replace cost ratios
- an interactive map where users can visualize actions, customers affected and failure risk per year; and
- a Results view that summarises yearly counts, budget utilisation and high-level KPIs, and exports audit tables/CSVs for integration into existing DSO planning processes.

Together, these tools have established a new process in which DSOs move from age-based and reactive renewal towards a systematic, data-driven, risk- and consequence-based asset management workflow.

3.5.3. The application

The tools are currently used in simulation, testing and pilot environments.

In a simulation environment

The digital-twin and Monte Carlo simulation framework is used to model cable failures and maintenance actions over many years. This allows testing of different maintenance and reinvestment strategies virtually and to quantify effects on SAIDI/SAIFI, outage costs and budgets before anything is implemented in practice.

In a testing environment

The analytics and optimisation modules have been run offline on operational datasets from Danish DSOs. Historical fault, GIS and asset data are used to train and validate the Neural Weibull risk models and to test the optimisation engine, without affecting live grid operations.

In pilot projects

The full PAMSEN pipeline has been demonstrated as pilot decision-support studies on real Danish distribution grids (e.g. networks operated by Dinel). Here, the tool produces concrete multi-year renewal plans and risk maps which asset managers review alongside their existing planning processes, providing a realistic pilot use while still being separated from day-to-day control of the grid.

3.5.4. The challenges

The main challenges were related to data and integration for predictive asset management rather than the modelling methods themselves. It was initially assumed that DSOs could easily provide comprehensive, well-structured asset, GIS, fault-history and smart-meter data. In practice, these datasets were heterogeneous, sometimes incomplete, and not always stored at the temporal or spatial resolution planned for use. Considerable effort had to be spent on cleaning, harmonising and validating data before reliable prediction models could be trained. In some cases, data sources expected to be exploited (for example accurate age of cables, historical faults, and detailed environmental information) were either unavailable or not accessible, which forced the redesign of parts of the modelling pipeline around coarser, more basic data.

A second challenge was building sufficient trust and usability around the predictive asset management outputs. Asset managers needed to understand and challenge the risk scores and failure probabilities rather than treating them as a black box. This required additional work on explainability, visualisation and scenario analysis, and on aligning multi-year risk forecasts with the DSO's existing investment planning processes and budget cycles. The key lessons learned are that data readiness is often the real bottleneck in predictive asset management projects, and that model development must go hand-in-hand with data governance and close collaboration with utility experts to ensure that the predictions can actually be used in day-to-day asset investment decisions.

3.5.5. Recommendations for future users

For organisations that want to implement similar predictive asset management solutions, the main recommendation is to start with the data and the business question, not with the algorithms. Clearly define the asset-management use case (for example, “which cables should we replace in the next 10–15 years under a fixed budget and reliability target?”) and then conduct a realistic audit of available data: asset registers, GIS, fault history, load/consumption data and relevant environmental information. Expect that these datasets will be heterogeneous and incomplete, and plan dedicated effort for data modelling, cleaning and harmonisation before model development starts.

On the analytics side, building a modular pipeline is recommended: a failure-risk model that can handle censoring and varying data quality, a consequence model that links failures to customers and energy not supplied, and a multi-objective optimisation layer that translates risk into concrete renewal plans under budget constraints. This separation makes the solution easier to validate, explain and maintain, and allows each part to be improved independently as new data becomes available.

Equally important is the implementation and change-management strategy. Co-design the tool with asset managers so that risk scores, maps and renewal plans fit directly into existing planning processes and regulatory reporting. Start by using the tool offline as decision support in pilot studies on real networks, compare its recommendations with current practice, and iterate. Aim for a software-only, vendor-agnostic solution that reads from existing systems (GIS, SCADA, asset databases) instead of replacing them.

Finally, invest in visualisation and transparency so that engineers can understand why certain assets are ranked as high risk. This is crucial for building trust and ensuring that predictive asset management becomes part of day-to-day investment decision making.

3.5.6. Steps for the full implementation

For full implementation of PAMSEN, several building blocks are still missing. First, utilities need more complete, standardised and regularly updated asset, GIS, fault-history and environmental datasets. In the project the research team focused on data that were already accessible and of sufficient quality, but many potentially valuable data sources are still either not collected at the right granularity or not integrated in a consistent way. Automatic updating of these datasets and common data models across DSOs are prerequisites for running PAMSEN as a routine planning tool rather than as a one-off study.

Second, the tool needs deeper integration into existing operational platforms and workflows. At the time of the publication of this Casebook, PAMSEN can be run as a stand-alone decision-support tool, producing risk-based rankings and multi-year renewal plans that are reviewed by asset managers. For full deployment, its outputs should be embedded into the asset management systems, with user interfaces and processes that align with established investment planning cycles, documentation requirements and approval procedures.

Key barriers and hindrances are therefore not technical but organisational. Data availability and quality vary widely between utilities, and defining internal data models and governance structures takes time. The electricity sector is conservative, procurement cycles are long, and many DSOs already have contracts with large international vendors, which can slow down the adoption of a new, analytics-driven planning approach. Larger-scale demonstrations and strong reference cases are needed to overcome these barriers and to build confidence that predictive asset management can be integrated safely into everyday asset investment decisions.

3.5.7. How to measure the success of the innovation

The research team considers the implementation a success because the predictive asset management approach has been developed, demonstrated on real Danish distribution grids and shown to outperform conventional planning rules on concrete KPIs.

In the Dinel 10 kV case study, the NWPH-based risk model was trained on several years of documented cable interruptions and clearly outperformed both a classical Weibull-Length model and a naïve ranking in terms of fault-capture versus cable length. Uncertainty in the reliability forecasts remained low, which is crucial for long-term planning. Simulations over 2023–2033 showed that, if no proactive replacements are made, the annual risk from ageing PILC cables grows from about 13,500 to almost 24,800 customers interrupted per year. Using the risk-based renewal strategy with the same budget reduces cumulative outage costs by up to 6.16 million DKK and cuts mean SAIDI by around 4 minutes compared to alternative strategies.

The optimisation studies further demonstrated that the reliability-aware multi-objective planner systematically dominates age-based and simpler heuristic approaches. For a fixed annual budget, it generates Pareto-optimal renewal portfolios that replace between roughly 20 and 133 cables, giving planners a transparent menu of options that achieve lower outage costs and better SAIFI/SAIDI/ASIDI values for the same investment. Through PAMSEN, these results are turned into concrete per-cable action plans and KPIs (e.g. customers affected avoided, risk reduction), which have been used in pilot decision-support studies with the partner DSOs. Altogether, this demonstrates that the innovative approach delivers measurable reliability improvements and socio-economic benefits using only existing utility data and software, indicating the implementation has been successful.

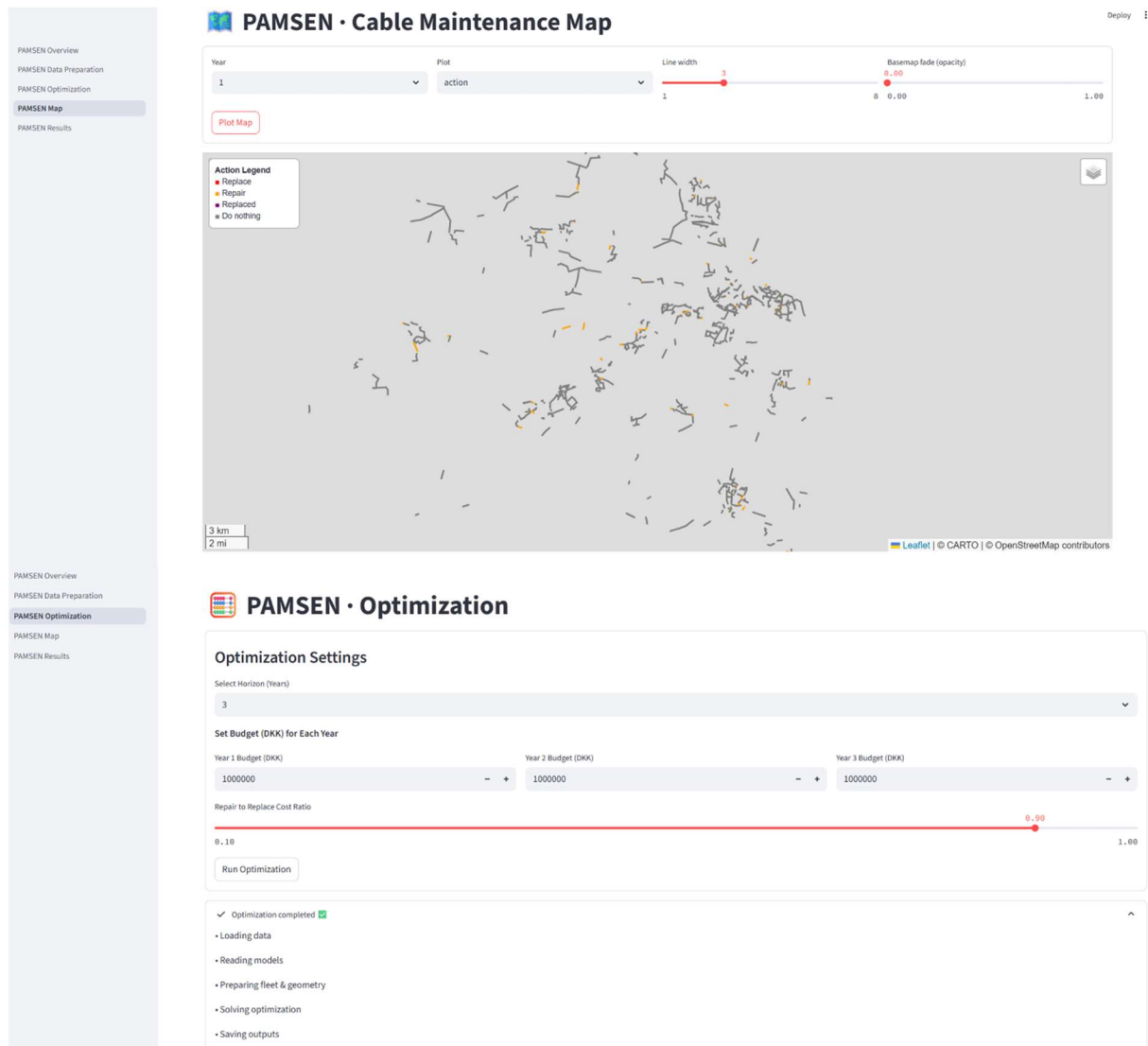
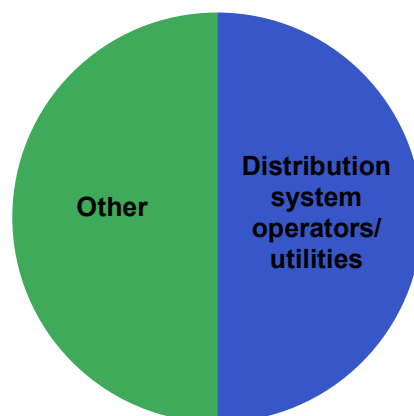


Figure 23. PAMSEN developed software

3.5.8. Actors contributing to the innovation

The distribution system operator and research contributed to this innovation.

Which stakeholders contributed to the innovation?



3.6. Germany 1: Joint regional scenario development for long-term distribution network planning

Author: Jirapa Kamsamrong (OFFIS Institute for Information Technology)

Contributing author: Dierk Bauknecht (OEKO Institute)

Phases addressed: strategic foresight, strategic direction, development options

3.6.1. The start

Germany is committed to achieving climate neutrality by 2045. This has driven rapid growth in DERs and significantly increased new grid connections at medium- and low-voltage levels. Rising connection demand, regulatory obligations, and requirements for system resilience are reshaping distribution network planning. Traditional purely top-down planning approaches are no longer sufficient for today's system, which has evolved into a decentralised structure.

Since 2012, TSOs have been required to submit a Grid Development Plan (Netzentwicklungsplan, NEP) to outline the transmission infrastructure needed to achieve climate neutrality by 2045. Building on this experience, Section 14d of the German Energy Industry Act (EnWG) extended a similar obligation to the distribution level.⁴¹ From 2024 onward, DSOs with more than 100,000 customers are required to submit a Grid Expansion Plan (Netzausbauplan, NAP) on a biennial basis, with a joint regional scenario as a mandatory part of the submission. While smaller DSOs are not required to publish their own plans, their network data feeds into the broader planning framework through their upstream reporting DSO, ensuring that NAP and regional scenarios capture local grid information.

3.6.2. The innovation

Long-term distribution planning requires coordination across actors. Joint regional scenarios replace fragmented approaches with a shared goal towards climate neutrality. DSOs in Germany have established six regional scenarios, each bringing together DSOs and relevant stakeholders in the region to develop a shared scenario, aligning assumptions, methodologies, and datasets.

This improves transparency and consistency while ensuring coherence with national planning frameworks and other stakeholders. This is a meaningful transformation towards a coordinated, forward-looking approach. The scenario-based planning is built on shared assumptions and agreed methodologies and requires both institutional buy-in and practical coordination across organisations that may have different planning cultures and timelines. In addition, German network operators also follow the Network Optimisation before Reinforcement and Expansion (NOVA) principle, which prioritises efficient use of existing infrastructure before investing in new transmission.⁴² Together, meeting regulatory requirements and the collaboration transformation have driven DSOs toward a more coordinated and forward-looking approach to sustainable long-term grid planning.

3.6.3. The application

During joint regional scenario development, DSOs within each region conduct joint working sessions, apply common data collection methods, and agree on shared sources and analytical frameworks.

⁴¹ https://www.gesetze-im-internet.de/enwg_2005/_14d.html

⁴² <https://www.vde.com/en/fnn/topics/network-operation-safety/4121-en>

A standardised questionnaire and template, developed nationally under the coordination of the German Association of Energy and Water Industries (BDEW), the Association of Municipal Companies (VKU), and the Federal Network Agency (BNetzA), is applied consistently across all six regions and aligns with the machine-readable tables published by BDEW for each DSO's Grid Expansion Plan submission. Feedback from municipalities and non-reporting DSOs is incorporated by their respective upstream DSOs as part of the regional scenario development process. Figure 26 illustrates the process in the Western planning region, showing how alignment is ensured with TSO planning and national targets while adequately capturing regional conditions and local inputs.



¹In addition, regionalized National Charging Infrastructure Control Center data is taken into account

Figure 24. Process for forecasting the value of Western regional scenario⁴³

This approach ensures consistency across distribution-level planning for all regions. All DSO action plans are published transparently every two years on a central national platform at www.VNBdigital.de (Figure 27), which has been operational since January 2023. From 31 October 2026 onward, distribution system operators will publish their grid expansion plans every two years, with the corresponding regional scenarios released up to ten months in advance, alongside a public consultation phase for stakeholder input.



Figure 25. National distribution network portal (www.vnbdigital.de)⁴⁴

3.6.4. The challenges

Developing a joint regional scenario is challenging because it requires alignment across multiple actors, datasets, and planning assumptions. A key challenge is refining national scenario frameworks against regional evidence, particularly where local project pipelines, land availability, and sector developments diverge from national forecasts.

⁴³ <https://www.vnbdigital.de/region/qbStFC9xdh6aopKey>

⁴⁴ <https://www.vnbdigital.de>

The process is further complicated by differences in data quality and interpretation across network operators, including inconsistencies in the use of installed capacity and active power, duplicate entries, and the need for post-processing before data can be used reliably.^{45,46}

Uncertainty remains for emerging developments such as data centres, electrolyzers, battery storage, electric mobility, and electrified heating. Many of these depend on connection requests or projects at different stages of maturity, making their timing, location, and likelihood difficult to assess. In some areas, such as municipal heat planning, local data remain incomplete, limiting the precision of assumptions. At the same time, changing policy and market conditions can quickly alter inputs and require adjustments. Scenario development is therefore an iterative process requiring continuous refinement, validation, and coordination, as shown in Figure 28.

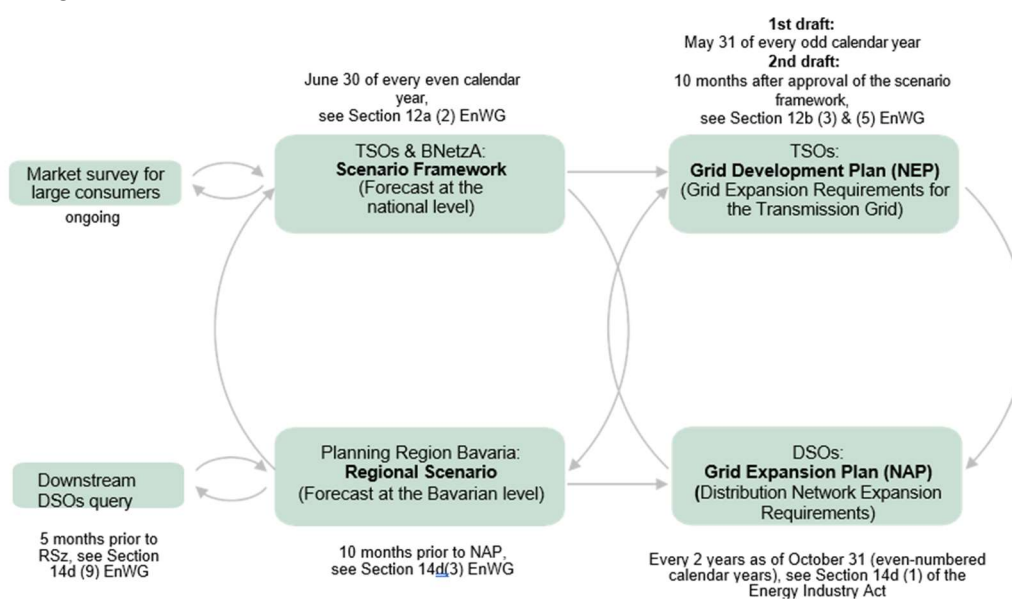


Figure 26. Interconnection of grid development plan and grid expansion plan⁴⁷

3.6.5. Recommendations for future users

Formalising coordination structures between DSOs, TSOs, and other stakeholders, with defined roles and responsibilities for updating joint scenarios, is an essential first step. Sustained stakeholder engagement helps ensure that joint scenarios remain realistic and reflect emerging developments in demand, generation, and technology. In parallel, establishing common data sharing aligned with the FAIR (Findable, Accessible, Interoperable, Reuseable) principle, including shared definitions, formats, and transparent methodologies, helps build trust and reduce inconsistencies from the outset. Investing in shared digital infrastructure, such as centralised platforms for data and knowledge exchange and public transparency, supports sustainable long-term coordination. Reskilling and upskilling the workforce are essential to supporting a coordinated approach to joint scenario development and forward-looking grid expansion planning.

⁴⁵ <https://www.vnbdigital.de/region/NBTZAyZhZudMDTBsn>

⁴⁶ <https://www.vnbdigital.de/region/Tz66ydsjQMNE4pji6>

⁴⁷ Regional Scenario 2025: Planning Region Bavaria.
<https://www.vnbdigital.de/region/Tz66ydsjQMNE4pji6>

3.6.6. Steps for the full implementation

Full implementation requires formalising regular coordination processes between DSOs, TSOs, and relevant stakeholders for scenario and grid expansion updates. Developing shared data platforms and data exchange mechanisms will further improve accessibility and interoperability across regions. Regulatory support remains important to align planning requirements and facilitate FAIR data and knowledge sharing across regions. Continuous improvement of data quality, integration of new data sources, and scaling of collaborative processes are essential.

3.6.7. How to measure the success of the innovation

Success of the joint regional scenario process can be assessed across several dimensions. At the most basic level, fewer discrepancies between DSO and TSO planning outputs and greater consistency in assumptions and datasets across regions indicate that alignment is improving. Ultimately, a reduction in the time and effort required for each update cycle signals that the process is becoming more efficient and less dependent on ad hoc coordination. The quality and consistent use of shared data formats and definitions, alongside active participation from DSOs, TSOs, municipalities, and other stakeholders, reflect the health of the collaborative process.

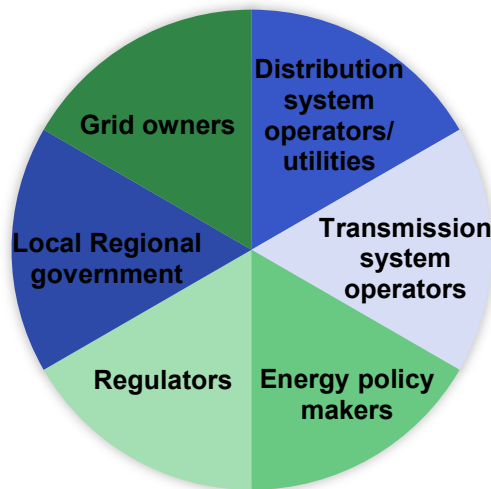
At the investment level, success means joint scenarios are translating into better coordinated and more cost-efficient grid expansion decisions. The success of the innovation is not just about completing the first joint scenario submission but about process maturity embedding the process into regular planning cycles across all regions, with consistent quality and reducing effort over time.

3.6.8. Actors contributing to the innovation

Developing joint regional scenarios involves a wide range of actors working across organisational and institutional boundaries. Within each region, DSOs lead the process, agreeing on shared assumptions, methods, and data sources. TSOs, both directly and indirectly connected, are engaged to ensure consistency between distribution and transmission level planning. Municipalities and state governments contribute local and regional demand and land use data, particularly around electrification trends and urban development. National industry associations provide standardised frameworks to ensure process consistency across all six regions.

Regulatory authorities set the legal requirements and submission timelines that structure the overall process. Standardisation bodies such as the Association for Electrical, Electronic, and Information Technologies (VDE), Forum for Grid Technology and Grid Operation (FNN) support technical regulations and at the European level defining supply quality, reliability standards, and grid connection requirements which provide a technical foundation that underpins distribution network planning.

Which stakeholders contributed to the innovation?



Within DSO organisations, the shift toward joint scenario development has both refined existing roles and created new ones across e.g., hosting capacity analyst, data scientist, data governance manager, cybersecurity specialist, sector-coupling specialist, regulatory affairs expert, grid planning coordinator. Effective cross-functional governance has become essential to ensure internal teams and external partners aligned across the full cycle, from planning through to implementation.

3.6.9. Next steps

Joint regional scenarios and grid expansion plans require regular updates. As the process matures, the focus shifts from establishing coordination to strengthening and scaling it toward becoming standard planning practice across all regions.

Improving the quality and accuracy of scenarios requires progress on several fronts. Better distribution grid observability, through smart meter data and substation monitoring, will sharpen scenario inputs, alongside more advanced modelling tools that capture the interaction between demand, generation, storage, and flexibility. Regional governments and municipalities hold essential local knowledge on energy transition plans, heat demand, and grid conditions that is not yet fully captured in the process. A regulatory framework defining their roles and responsibilities would help ensure this local input is systematically integrated.

Strengthening a standardised national framework will support reproducibility and repeatability across regions and accelerate future update cycles. This requires sustained investment in workforce capability across planning and stakeholder engagement. Deepening collaboration with existing stakeholders and engaging new actors, including academia and research institutions, will be essential to drive the innovations in grid planning needed to keep pace with emerging technologies as the clean energy transition accelerates.

3.7. Germany 2 (Stadtwerke Schwerte): Multi-stage transformation approach

Authors: Jannis Mimberg (Stadtwerke Schwerte), Dr. Alexander Hobert (Stadtwerke Schwerte), Dr. Chris Kittl (Stadtwerke Schwerte), Daniel Feismann (TU Dortmund), Prof. Dr. Christian Rehtanz (TU Dortmund)

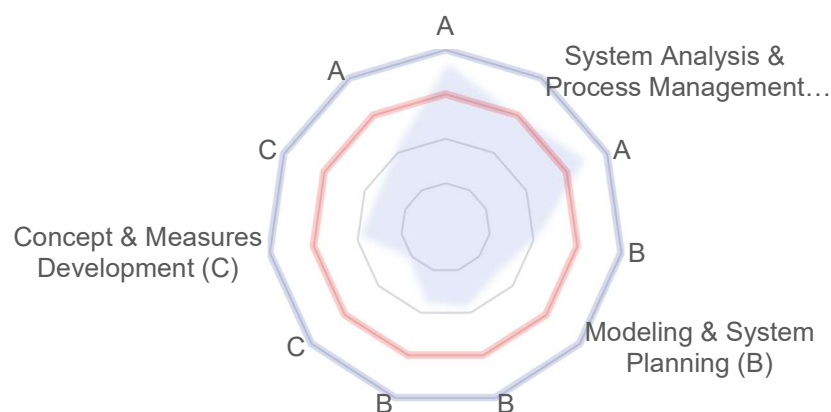
Phase addressed: development options

3.7.1. The start

The energy transition requires DSOs to significantly enhance their strategic planning processes. Smaller DSOs, such as Stadtwerke Schwerte, face particular challenges due to limited personnel and organisational resources. While only a limited amount of strategic planning was necessary in the past, it is becoming increasingly indispensable due to the following reasons:

- prospective decommissioning of gas grids
- fundamental decisions on the development of hydrogen infrastructure
- the electrification of additional consumption sectors, the increasing decentralisation of electricity generation, and
- the expansion of heating grids.

At the same time, cross-sector interdependence continues to increase, making an integrated view of the energy system essential. However, full implementation of this transformation process is not feasible in the short term, as not all the necessary resources are currently available. To meet these challenges, Stadtwerke Schwerte is pursuing a multi-stage transformation approach (Figure 27).



typical initial state for small DSOs ■ intermediate goal ■ integrated planning

Figure 27. Maturity level of a small DSO's strategic planning in relation to the integrated planning process

In practical implementation, DSOs often face gaps particularly in modelling, grid calculations, and the derivation of appropriate measures. The following section describes the steps undertaken to reach the intermediate goal on the path toward integrated planning.

3.7.2. The innovation

The core of the approach is the establishment of a **consistent overall process within an asset management system** in accordance with ISO 55001, which systematically translates corporate goals and strategies, such as decarbonisation, into concrete construction measures. In addition, human resources were expanded to cover the additional technical and organisational tasks.

In order to define a realistic interim goal in view of the limited resources available, a coupled planning approach was chosen. This is based on the approach described in Heise et al., in which strategic planning continues to be carried out on a sector-specific basis, but the results are combined in a shared roadmap.⁴⁸ This results in an integrated expansion plan that includes key elements of an integrated perspective, such as the identification of suitable locations for sector coupling technologies, without requiring complete modelling of the entire energy system or fundamental changes to existing strategic planning approaches.

In addition, a modular structure for a comprehensive energy scenario was developed and regionalised based on the regulatory reference scenarios. This ensures consistent input for sector-specific planning that is in line with national development goals and thereby provides an important basis for the coupled planning approach. A newly established process also ensures that plans are only updated in the event of significant changes to the assumptions underlying the specific plans. The modular structure supports the clear allocation and identification of the affected grids. To ensure that the planning basis is up to date, the planning process was also adapted to the update cycle of the reference scenarios used. At the same time, an iterative process was established that makes it possible to use regional influencing factors and the results of the strategic planning itself as triggers for a new revision.

3.7.3. The application

The measures implemented to date form the basis for greater integration of strategic grid planning at Stadtwerke Schwerte and provide a practical example of how integrated planning can be advanced under the typical resource constraints of small DSOs. The modular structure of the energy system scenarios ensures consistency with the scenarios of ongoing strategic planning projects and creates a structure for the future use of an integrated energy system scenario. Another significant advance is that strategic planning is increasingly influencing the design of operational planning. This means that corporate strategies are being broken down into concrete infrastructure measures. In addition, the integrated approach has led to a greater focus on sector coupling technologies, which supports a systemic perspective on the development of all divisions. Beyond their application in grid and operational planning, the contents developed are already used as a strategic reference in other parts of the organisation. Consistent assumptions and clear interfaces have also strengthened the management of external service providers, leading to higher quality and comparability of results.

3.7.4. The challenges

The results obtained so far pose specific challenges. These include the detailed design of the coupling of planning results and the precise determination of the resources required for fully integrated planning.

⁴⁸ J. Heise *et al.*, "Coupled Multi-Energy Grid Planning -Paving the Way from Isolated to Integrated Planning," 2023.

On this basis, a transformation path must be developed that fully exploits the potential of sector coupling and ensures the long-term further development of the strategic planning process.

3.7.5. Actors contributing to the innovation

Only the distribution system operator contributed to this innovation.

3.7.6. Next steps

The further development of the approach focuses on its enhanced operationalisation. This includes the following aspects which are currently being implemented:

- integration of strategic planning outcomes into short- and medium-term grid planning
- continued refinement of the tool used to couple sector-specific planning results
- completion of the first full implementation cycle of the asset management system in accordance with ISO 55001.

In addition, the following elements are to be carried out on a continuous basis in the future:

- ongoing review of regional influencing factors and their implications for the regional energy system scenario
- continuous process improvement within the asset management system.

A comprehensive review of the regional energy system scenario will follow the next revision of the national regulatory reference scenarios.

3.8. Italy (e-distribuzione)

Author: Serena Cianotti (Enel Grids)

Contributing authors: Fabio Cazzato (e-distribuzione), Luca De Carolis (e-distribuzione), Simone Ferrero (e-distribuzione)

Phases addressed: strategic foresight, strategic direction, development options

3.8.1. The start

Increasing the share of renewable energy sources in the energy mix and the electrification of final energy uses in all sectors represent viable solutions for the energy transition. Distribution networks are expected to be strongly influenced by and influence such transformation while withstanding progressively increasing climate impacts. This will require a revolution at the power system level, starting from the planning phase. The future roadmap of a power distribution system shall include not exclusively network upgrades but also non-network solutions focusing on operation strategies exploiting the flexibility gathered from distributed energy resources. To design new transition-ready planning tools for distribution systems able to consider these aspects, the role of flexibility has been analysed on a real-world, large-scale test case characterised by a high number of connection requests and an expected high electrification rate. Stress has been put on correctly assessing the value of flexibility in planning the distribution system development.

It is crucial to adopt a risk mitigating planning procedure of future design of a distribution grid. European rules on distributed flexibility and NRA requests for pilot projects on local flexibility services asked the DSO to define a tool beyond the usual deterministic approach on load flows forecast and network planning. The DSO lead the proposal of the pilot and the research projects, including the innovative approach to network planning.

3.8.2. The innovation

The innovation was the development of a flexibility needs assessment in medium-long term distribution network planning, with a stochastic approach for power flows assessment and proper CBA.

In the past, grids were planned to allow for all violations possible. That way many grids were over-built to cater for the worst-case scenarios. Nowadays increasing feeding in of RES and energy-intensive loads makes this approach unsuitable. Thus, new tools became necessary that include the flexibility from generator dispatch, demand-side integration, control of transformer tap changers, reactive power management, and online reconfiguration as a development option to be considered both technically and financially. The new approach includes the following approaches incorporating the risk of dealing with uncertainties into account:

- modelling of energy demand
- georeferenced forecasting
- risk assessment
- probabilistic calculations
- flexibility versus copper and iron development (non-infrastructure options).

In a case study, the impact of flexibility from DERs has been analysed on a large-scale regional power distribution system in the south of Italy, considering a future scenario, characterised by several distributed RES plants (mainly photovoltaics), high electrification of final energy uses (higher than the national average) but a relatively low ratio between electricity demand and generation (many feeders manifest similar amount of consumption and production), and still young electric mobility.

Thus, risk-oriented planning becomes necessary. A risk assessment workflow and calculation were established by calculating the forced outage rate of the network element and the occurrence probability of the specific customer's operating conditions. The risk component is calculated as hours of violation per year.

In more detail, daily profiles are used for generation and demand, with uncertainty in the power consumed or generated modelled through normal probability density functions. This leads to normal probability distributions for all nodal voltages and line currents. A linearised Probabilistic Load Flow (PLF) is solved for each of the 24 hours of the typical days, both in normal operating conditions and in all the emergency configurations (obtained by removing one network element at a time according to the classical $N - 1$ analysis).⁴⁹

From that the probability for not complying with technical limits is assessed (p_{tcv}). By multiplying p_{tcv} and the occurrence probability of the relative operating condition, p_{bf} (the hour of the d^{th} typical daily profile when the b^{th} network configuration in the $N - 1$ security analysis is in force), the corresponding risk component is determined (R_{bf}).

The sum of all risk components greater than zero gives the total risk of the network, that will be compared with acceptable risk. From that value, measures like DER active management or network reinforcement can be taken.

⁴⁹ G. Celli, S. Mocci, F. Pilo, and R. Cicoria, "Probabilistic optimisation of MV distribution network in presence of distributed generation," in *Proc. PSCC*, Jun. 2002, pp. 24–28.

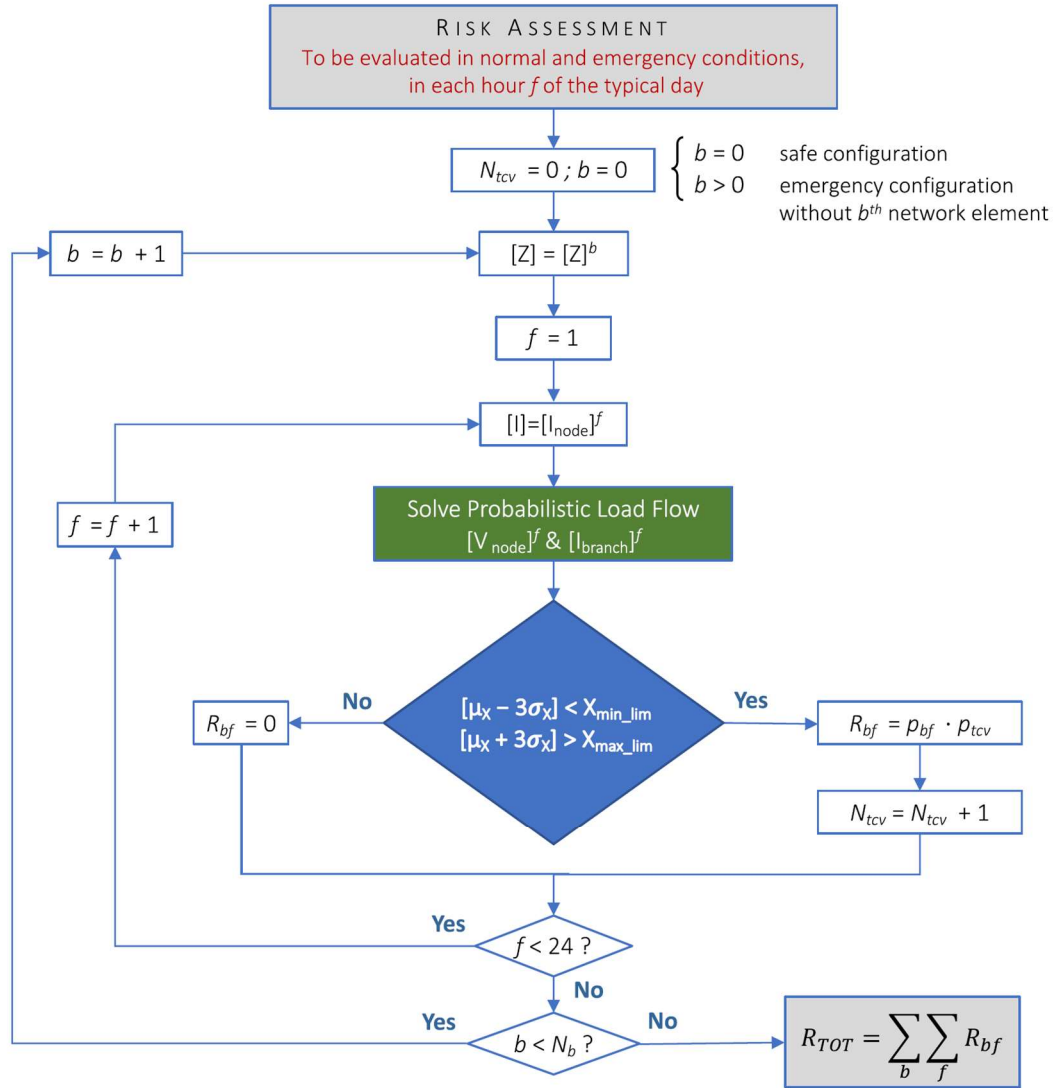


Figure 28. Identification of potential contingencies (ptcv > 0) and total

3.8.3. The application

The tools and processes are used to support medium and long-term network planning under uncertainty. The study involved 43 primary substations, supplying around 400 MV feeders (total length 8,129 km), and 7,700 secondary substations. The area is predominantly rural, with overhead feeders extending up to 90 km, alongside shorter urban cable sections. A medium-term (2030) and a long-term (2050) planning horizon were considered, coincident with the deadlines of the European climate targets. The electrification scenario includes significant demand growth across all sectors, with particularly sharp increases in transport (driven by EV adoption) and substantial PV capacity additions. Customer behaviour throughout the year has been modelled through typical daily profiles derived from DSO measurements and standard profiles differentiated by sector. A geospatial forecasting method was used to translate national energy plans down to the level of individual secondary substations, combining DSO data with publicly available information such as building types and vehicle registrations per municipality. A probabilistic approach allows the DSO to assess power flows across multiple scenarios, identify flexibility needs, and compare grid reinforcements with flexibility solutions within a CBA framework.

3.8.4. The challenges

Main challenges included data availability, higher computational complexity, and the transition from deterministic to probabilistic planning approaches. Transitioning from deterministic to probabilistic planning also required adapting tools, workflows, and assessment criteria, as the new methodology introduces a fundamentally different approach to evaluating network adequacy and investment priorities. Also, the geospatial load forecast highlighted the need for broader and more granular data availability; translating national energy plans into local scenarios requires continuous integration of DSO operational data with external datasets (building types, car ownership per municipality, etc.), calling for updated data management systems and processes.

3.8.5. Recommendations for future users

It is recommended to start with pilot projects, invest in data and skills, and progressively integrate probabilistic planning into existing planning and regulatory frameworks.

3.8.6. Steps for the full implementation

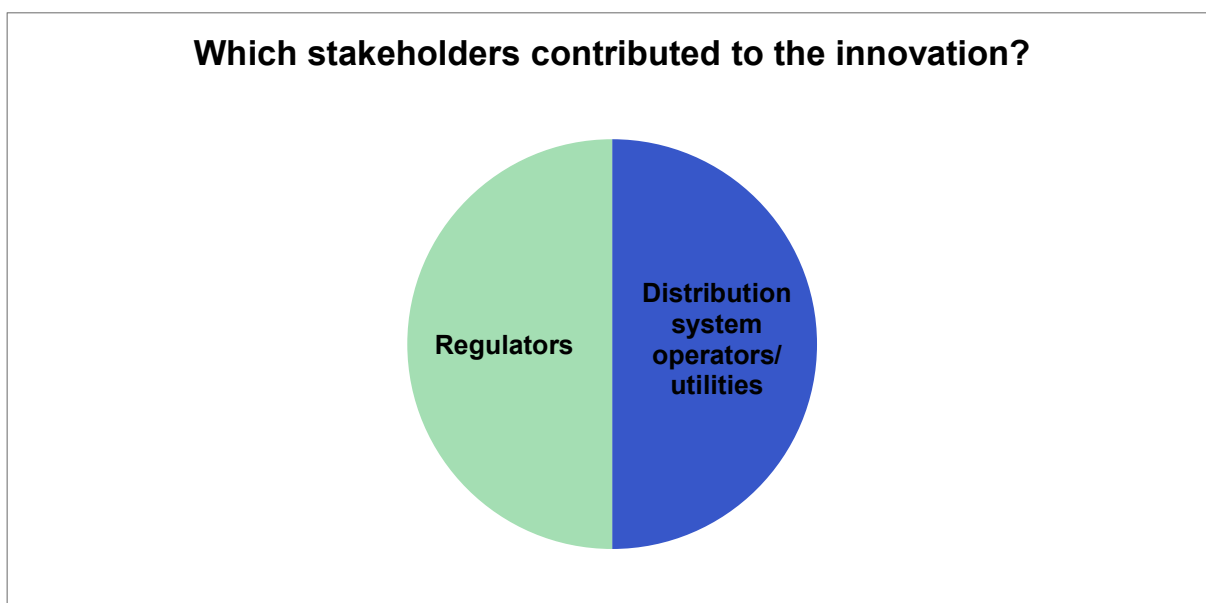
Full implementation requires supportive regulatory frameworks at both the European and national levels. Several building blocks are still needed: a deeper investigation of flexibility from low voltage resources is underway. Coordination between DSOs and TSOs is essential, as both levels of the system increasingly depend on distributed flexibility. Finally, engaging all potential flexibility providers – generators, consumers, prosumers, and aggregators – is key to making local flexibility markets work at scale.

3.8.7. How to measure the success of the innovation

The key finding is that the methodology used to assess hosting capacity dramatically affects the planning outcomes. The traditional deterministic approach, assuming worst-case conditions as certain, leads to a significant overestimation of the upgrades needed. On the contrary, a probabilistic approach reveals that most of the existing network already has sufficient capacity to accommodate the first wave of the energy transition. Flexibility from local markets can further increase hosting capacity, and the services required were modest in both magnitude and duration. Importantly, flexibility does not eliminate the need for network upgrades in the long run, but it does allow DSOs to accept more renewables now while planning infrastructure investments more efficiently over time.

An important insight from the study is that flexibility does not eliminate the need for network upgrades in the long term; the same investments will eventually be required. What flexibility does is buy time, allowing DSOs to accept more renewables immediately while planning long-term investments more efficiently.

3.8.8. Actors contributing to the innovation



The innovation was developed through a collaboration between E-Distribuzione (Italy's largest DSO, part of the Enel Group), which provided real network data and the operational context, and the University of Cagliari, which developed the probabilistic planning methodology and geospatial forecasting tools. Through this approach, the DSO takes on a new role as an energy transition facilitator, actively integrating flexibility services into planning and operation.

To implement this innovation the DSO needs to closely coordinate with the TSO for distributed flexibility effective management for the whole electrical system.

3.8.9. Next steps

Next steps include scaling up the probabilistic planning approach beyond pilot projects, refining models and assumptions based on operational data, and further integrating flexibility resources and regulatory requirements into the planning framework.

Scaling up the innovation presents challenges related to data availability and computational requirements, integration with existing planning processes, and alignment with regulatory frameworks.

Flexibility can be a valid option in helping grid management, but more importantly an opportunity to reconsider planning by applying a new revolutionary risk-oriented approach that may lead to modify the way distribution grids have been planned and operated so far.

3.9. Italy (TE.R.R.A.)

Authors: Antonio Iliceto, Simona Ruggeri

Phases addressed: strategic foresight, strategic direction, development options, assessment and decision, implementation

3.9.1. The start

The energy transition requires a shared commitment to achieve national and European decarbonisation goals, develop networks, storage, and over 70 gigawatts (GW) of new renewables through efficient and environmentally sustainable regional planning in Italy. Digitisation is the driving force behind major projects and visions; technological innovation is the necessary tool to ensure coordinated, integrated, and effective planning of electricity infrastructure across the country. With the large number of generation initiatives and requests for connection to the national transmission grid (Figure 31), the Energy Decree has entrusted Terna, at the centre of this evolution, with the task of creating a new digital portal for efficient territorial planning.

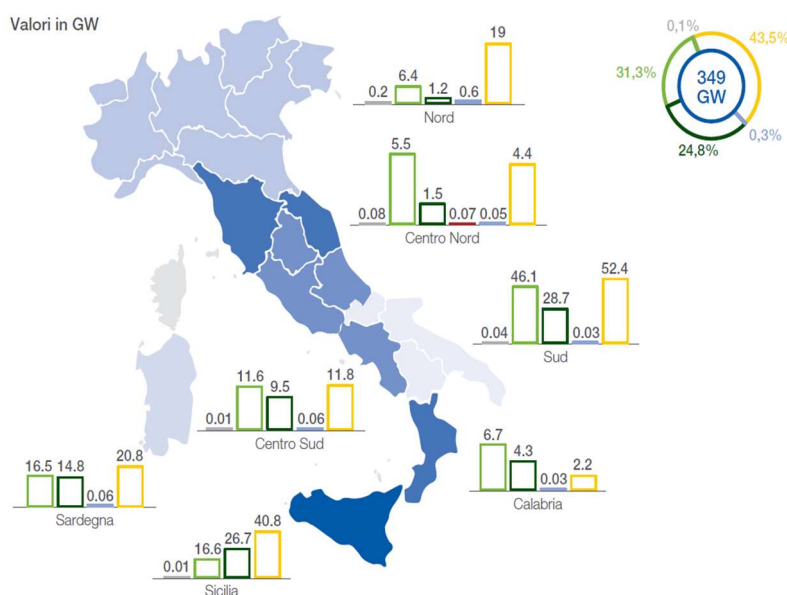


Figure 29. Connection requests (GW)

3.9.2. The innovation

With 349 GW of connection requests concentrated unevenly across the country, approximately 80% in Southern Italy and the islands, managing connections at a national or even regional scale was no longer effective. A new model was used based on territorial integration through microzones (Figure 30). The concept of “**microzone**” was introduced, a portion of sub-regional (and, therefore, sub-zonal) National Transmission Grid (NTG). This allows the main **intrazonal constraints** on energy transport to be modelled effectively, while maintaining, if necessary, compared to a nodal approach, **the modelling simplicity** necessary for the problem under consideration.

To manage the connection requests, the new tool Territorio, Reti, Rinnovabili e Accumuli, or “Territory, Grids, Renewables and Storage” (TE.R.R.A.) has been developed.



Figure 30. 76 microzones in Italy

TE.R.R.A. is the first step in a process involving the system's key players. A cutting-edge, dedicated, and profiled institutional communication tool, it provides administrators and legislators with timely and detailed access to all grid data, including approximately 6,600 renewable plants, storage systems and consumer users with an accepted connection solution. This spans about 40,000 plants in operation, from generation initiatives to plants and power lines, both currently and in operation, through navigable multilayer maps. It contains all the information, phases, and content of monitoring reports on the progress of the processes for connecting plants to the national electricity grid, the necessary development interventions planned and the power lines already in operation, the registry of plants already in operation, connection requests, and the progress of procedures for new generation initiatives, especially renewables and storage.

This enormous wealth of information is the result of constant work on data quality and the digitalisation of systems and processes regarding the status of requests and the geographical location of each piece of infrastructure. This represents a true revolution in assistance and support tools to facilitate access to this content. Digital evolution is one of the pillars of Terna's 2024-2028 business plan. Approximately €2 billion of the total €16.5 billion is earmarked for technological and digital innovation initiatives for an increasingly secure and resilient grid. This approach to the Twin Transition translates into a new digital platform for increasingly effective territorial planning and a further acceleration of authorisation processes, essential steps for the network of today and tomorrow.

Created in a context of exponential growth in requests for connection to the NTG and the absence of an adequate system for sharing information between Terna and the Authorising Bodies on plant development initiatives, the portal aims to share and make transparent and immediately available the information necessary for territorial planning, supporting the Stakeholders involved in the connection process. In particular, TE.R.R.A. provides strategic and relevant information on existing and future energy infrastructures, on the requests for connection of renewable plants, consumer users and storage, but also on national and regional constraints, with the aim of promoting and enabling efficient, integrated and sustainable territorial planning for the environment.

The structure of the portal, agile and interactive, allows users to explore and interact with information and data updated monthly, to obtain reports and download information in aggregate and detailed form regarding the plants in operation, connection requests and related trends, thanks to direct access to reports and the progress of the connection process and the authorisation process. In addition, it is possible to geolocate on an interactive and customizable map the precise information regarding plants in operation, connection requests and network infrastructures necessary for their integration into the electricity system. In this way, TE.R.R.A. favours a territorial analysis that takes into account the constraints and areas of protection identified by regional or national regulations. Through a dedicated section, it is possible to request information, make an appointment with Terna and upload documents.

In February 2025, the Italian government published a new piece of legislation (“DL Bollette”) which reformed Terna’s approach to grid connections for RES and storage plants. The reform introduces four key principles: (i) overbooking, allowing the issuance of connection solutions in excess of available capacity at the connection point; (ii) transparent and efficient microzonal solutions, where Terna periodically updates and publishes available connection solutions designed to fit expected policy targets and users can freely select their preferred solutions during an “Open Season” procedure; (iii) consistency between connection solutions and local context, with Terna taking over the designing and permitting process (previously carried out by applicants in “Round Tables”), strengthening technical interplay with regional Authorities; and (iv) a “First Permitted First Served” principle, whereby grid capacity is firmly booked only when the applicant obtains authorisation, overcoming the problem of virtual saturation of the grid.

Storage is also integrated in the framework. Integration of additional storage capacity is essential for intermittency of vRES. Current plans include:

- 53 GW of stand-alone electrochemical storage plants
- 24 GW of storage plants integrated with RES plants
- Approximately 9 GW of pumped storage and production hydropower plants.

New connection requests do not only include producers but also consumers, including data centres, and the transport sector (rail and ports).

3.9.3. The application

The microzonal approach is applied through the following workflow:

1. the national transmission grid is split into 76 microzones, each representing a sub-regional portion of the NTG
2. Terna performs intra-microzone and inter-microzone analyses, balancing energy offers and demand within each zone
3. Terna designs overall connection solutions at the microzonal level, locating new substations and lines, and identifying necessary grid enhancements
4. Terna updates and publishes available connection solutions
5. during an Open Season procedure, each applicant selects the best connection solution for their needs
6. Terna releases the STMG (Minimum Technical General Solution) to each applicant after the Open Season
7. final allocation of capacity occurs only upon obtaining the authorisation titles for the user facility. Each efficient distribution of connections guarantees that 2030 decarbonisation targets are met at the microzonal level.

On the portal side, TE.R.R.A. provides users with an agile and interactive structure enabling: exploration and interaction with monthly-updated data; download of aggregate and detailed reports on plants in operation, connection requests and trends; geolocation on interactive and customizable maps of plants in operation, connection requests and network infrastructures; territorial analysis taking into account environmental, landscape and cultural constraints identified by regional or national regulations; and a dedicated section to request information, schedule appointments with Terna and upload documents.

3.9.4. The challenges

The main implementation challenges include:

- ensuring data quality across approximately 40,000 plants and thousands of connection requests
- building effective TSO–DSO coordination for a common planning scenario
- transitioning from over 500 individual working tables to a centralised microzonal approach, requiring both regulatory support and stakeholder buy-in from regional authorities.

3.9.5. Steps for the full implementation

The portal, to date, provides restricted access with a national view for the Italian Regulatory Authority for Energy, Networks and Environment (ARERA), the Ministry of the Environment and Energy Security and Ministry of Culture and differentiated profiling for the Regions; subsequently, access will also be made available to proponents in accordance with the procedures established by ARERA.

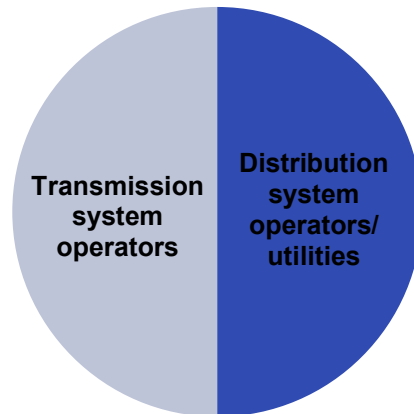
3.9.6. How to measure the success of the innovation

The portal is already online and actively used by institutional stakeholders (ARERA, MASE, MIC and the Regions), with planned extension to proponents. Its success can be measured through reduction in connection times thanks to the "First Permitted First Served" approach; optimisation of grid infrastructure sizing, as only truly necessary infrastructure is planned; progressive reduction of the over 500 active working tables as Terna's centralised microzonal approach replaces the previous fragmented system; and alignment between actual RES connections and 2030 decarbonisation targets at microzonal level. The main implementation challenges include ensuring data quality across approximately 40,000 plants and thousands of connection requests; building effective TSO–DSO coordination for a common planning scenario; and transitioning from over 500 individual working tables to a centralised microzonal approach, requiring both regulatory support and stakeholder buy-in from Regional Authorities.

3.9.7. Actors contributing to the innovation

The main actors behind this innovation are Terna, which not only introduced and developed the TE.R.R.A. portal, but also promoted the microzonal planning model underpinning the new integrated approach to grid connection and territorial planning, and the DSOs, which support this approach by providing distribution-level information and contributing to TSO–DSO coordination for a common scenario. Regulators and public authorities can be considered institutional enablers and key users of the portal, while proponents and consumer users are primarily beneficiaries of the innovation.

Which stakeholders contributed to the innovation?



3.10. Japan: Control system to leverage grid capacity

Author: Yuka Ogasawara, Renewable Energy Department, New Energy and Industrial Technology Development Organisation (NEDO); Tomoaki Minami, International Affairs Division, Commissioner's Secretariat, Agency for Natural Resources and Energy

Phases addressed: development options, implementation

3.10.1. The start

The innovation in this chapter concerns developing a control system to realise the Japanese “connect and manage”, systems that leverage grid capacity to enable early, cost-efficient interconnections.

The rapid growth of renewables has begun to create new challenges for the power grid in Japan as well. While large-scale grid congestion has not yet fully materialised, future congestion—especially in local grids—is anticipated as increasing volumes of variable renewable energy are connected. Conventional grid reinforcement alone would be costly, time-consuming, and could lead to excessive investment, since some network capacity constraints occur only for a limited number of hours per year. In such cases, grid enhancement will become excessive investment for the local community.

The key challenge, therefore, was how to accommodate large amounts of renewable energy efficiently while minimising unnecessary grid expansion and social costs. To address this, Japan developed the **Japanese Connect and Manage system**, which enables the grid to accept more renewable connections by actively managing congestion through renewable curtailment.

This system enabled the introduction of “non-firm grid connections”, allowing generators of 10 kW or larger including in distribution grids to connect earlier—even when physical grid capacity is insufficient—on the condition that their output can be curtailed during congestion events. The system is particularly relevant for PV and other renewables connected to distribution and sub-transmission networks, where reverse power flows can propagate congestion to upper-level grids.

A major obstacle in launching this initiative was the absence of an existing system capable of managing and controlling a large number of non-firm connections. The required solution had to handle vastly increased data volumes, integrate detailed distribution-level information, improve highly localised forecasting accuracy by TSO/DSOs, and standardize the specifications of generator-level devices such as inverters. Addressing these challenges required close collaboration among TSOs/DSOs, system vendors, forecasting specialists, and power generation operators.

As a result, the Connect and Manage system was developed as a NEDO project⁵⁰, began operation at TEPCO Power Grid in 2024, and is planned to be rolled out nationwide in phases (excluding Okinawa) by fiscal year 2027.

The management supported: Under the leadership of the Agency for Natural Resources and Energy and the OCCTO, the NEDO project was carried out in cooperation with NEDO, TSOs/DSOs, power generation operators, etc.

⁵⁰ NEDO Project: Next-Generation Power Network Stabilisation Technology Development for Large-Scale Integration of Renewable Energies (JPNP19002) [Next-Generation Power Network Stabilisation Technology Development for Large-Scale Integration of Renewable Energies | NEDO](#)

3.10.2. The innovation

Connect and manage system

This system retrieves information from the zone under monitoring including distribution grids, and, when congestion is expected to occur, the system sends orders to conduct curtailments, considering the supply and demand balance. This applies to all new or upgraded power sources of 10 kW or larger including in distribution grids.

In particular, PVs and other renewable energy sources are often connected to sub-transmission and distribution grids, and the reverse power flow from these renewable energy sources is pushed up to the upper grid through the transformers in substations, causing congestion. Therefore, the power sources that are curtailed during congestion are connected to the lower grid of the congested grid.

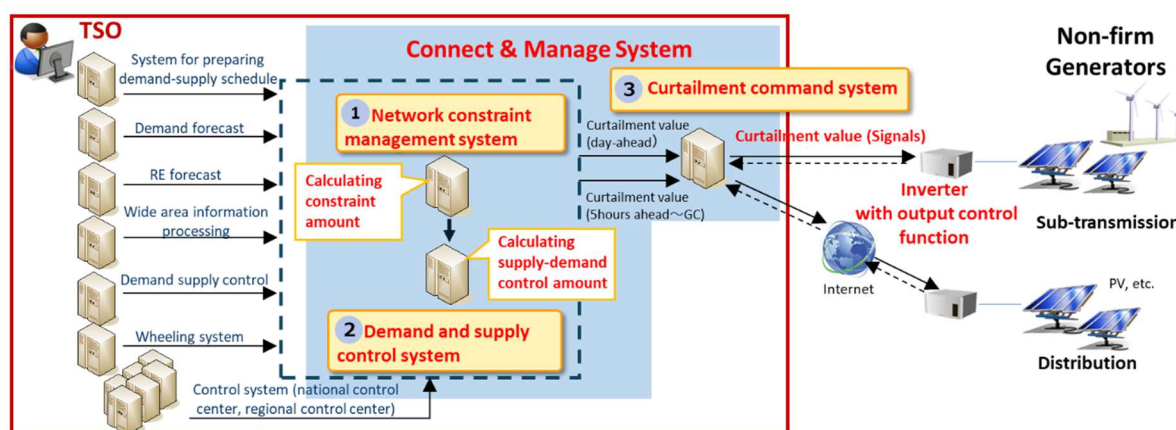


Figure 31. Connect and Manage System Configuration

3.10.3. The application

The matter had been discussed at several national councils, and each TSO is developing and operating a Connect and Manage system.

3.10.4. The challenges

Not only was the NEDO project to construct the specifications for Connect and Manage systems done during the COVID-19 pandemic, but it was also carried out in parallel with national discussions, which led to many changes to the logic and specifications.

At one point, it seemed as if we wouldn't be able to complete the project within the time frame, but we held regular meetings with the Agency for Natural Resources and Energy, the OCCTO and all parties involved worked together as one, and it was managed to move forward with system development and demonstration even in the short period of time and finally reached the conclusion of the specifications.

3.10.5. Recommendations for future users

- Connect and Manage is a strategic option.
- Start with making clear policy rules, invest in digital control systems, and scale up step by step through system design and close collaboration with stakeholders

3.10.6. Steps for the full implementation

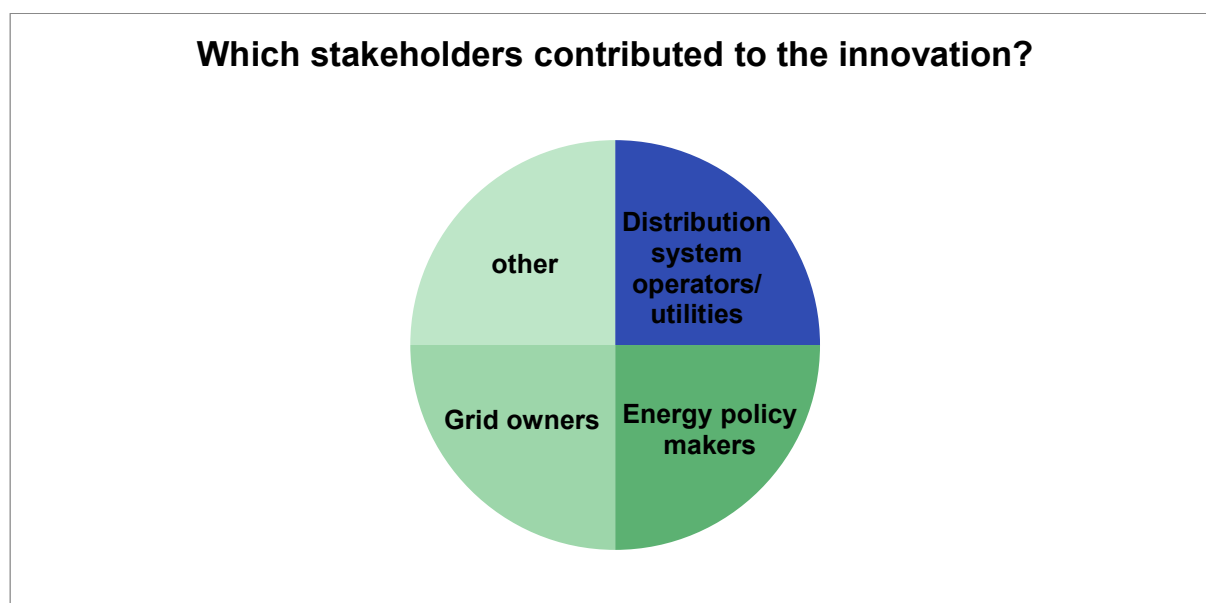
- Issues in actual operation have yet to be identified (such as the complexity of settlement procedures)
- This system is for curtailment only for now, and charging commands for grid-connected batteries cannot yet be issued from this system.

3.10.7. How to measure the success of the innovation

Under the revenue cap system in Japan, which aims to improve cost efficiency, TSO/DSOs are required to set and achieve plans to introduce a new congestion management method, and the NEDO project contributed to the realisation of this goal.

Also, the amount of power sources being considered for non-firm type connections and contract application capacity increased year by year, and as of June 2023, the amount of them including those under consideration for connection, had increased to approximately 70GW.

3.10.8. Actors contributing to the innovation



The Connect and Manage system calculates demand-supply and congestion and sends commands of curtailment. Thus, two-way communication devices were required on the power generator's side to receive commands and send actual values from a system during congestion, and its functionality needed to be verified.

3.10.9. Next steps

The NEDO Connect and Manage 2.0 project is considering adding a function that would enable this system to issue charging commands to grid storage batteries (BESS) when congestion is expected, which would increase social benefits.

Challenges in scaling up the innovation

In fully liberalised markets like Japan, where generation and transmission are unbundled, TSOs do not own controllable DERs. Therefore, new Energy Management Systems (EMS) must be developed on the TSO, DSO, and battery sides to enable signal exchange and charging/discharging control. Furthermore, third-party BESS are typically assumed to participate in various markets, such as the wholesale electricity market and balancing market, so verification of multi-service operation is required. The NEDO project is being conducted to confirm the feasibility and validity of these systems.

It will be important to seek close involvement from stakeholders from the system requirements definition stage.

3.11. Japan 2: Study of countermeasure methods to address issues for regional grids (interconnected microgrid) with renewable energy introduction

Author: Yuka Ogasawara, Renewable Energy Department, New Energy and Industrial Technology Development Organisation (NEDO); Tomoaki Minami, International Affairs Division, Commissioner's Secretariat, Agency for Natural Resources and Energy

Contributing authors: Kazuhiro Yoshiyama and Shinya Morita, Tokyo Electric Power Company Holdings, Inc.; Ryoya Yamamoto, Shunsuke Kawano and Nobuhiko Itaya, Mitsubishi Electric Corp.; Masayuki Kagita, Mitsubishi Electric Software Corp.; Akira Moriwaki, Central Research Institute of Electric Power Industry (CRIEPI)

Phase addressed: assessment and decision

3.11.1. The start

In recent years, large-scale power outages have occurred due to earthquakes, typhoons, and other natural disasters, highlighting the importance of strengthening the resilience of power infrastructure in Japan. As a response to this issue, Japan has considered enhancing resilience through the development of community microgrids (interconnected microgrids) utilising existing distribution lines.

When inverter-based renewable energy sources serve as the main power supply in such community microgrids, the power supply configuration differs from that of conventional power grids; therefore, it is necessary to identify technical challenges and develop appropriate countermeasures.

Accordingly, under a NEDO project, comprehensive efforts are being made to systematically identify the challenges arising from the transition to renewable energy as the primary power source, taking into account future changes in facility configurations, and to examine solutions to address these technical challenges.

Since June 2022, studies have been conducted under the NEDO STREAM project, in collaboration with electric power companies led by Tokyo Electric Power Company Holdings, as well as research institutions, manufacturers, and other corporations, with the aim of facilitating the smooth introduction of community microgrids in which renewable energy serves as the primary power source in the future.⁵¹

For this community microgrid study, Tokyo Electric Power Company Holdings is responsible for overall coordination, while Tokyo Electric Power Company Power Grid, the Central Research Institute of Electric Power Industry, Mitsubishi Electric, Okinawa Electric Power Company, and Nextems are each responsible for specific study areas, jointly promoting the project.

⁵¹ NEDO Project: Future-generation Power Network Stabilisation Technology Development for Utilisation of Renewable Energy as the Major Power Source (STREAM Project) (JPNP22003)

3.11.2. The innovation

In a community microgrid that utilises existing distribution lines—with inverters as the main power source during islanded operation—when inverter-based renewable energy serves as the primary supply, the power-source configuration differs from that of a conventional grid, and therefore appropriate measures are required. Accordingly, the following countermeasures are being studied:

• Inrush mitigation during black start

A key challenge in black start—energising the system to 6.6 kV from an outage state—is that magnetising inrush current may occur in grid-connected transformers. This can drive the main power source into an overcurrent condition and, in some cases, lead to a complete blackout. To verify the effectiveness of inrush mitigation, a soft-start test was conducted in which the voltage was ramped up to 6.6 kV over several seconds from the de-energised state. The results showed that the inrush current was sufficiently reduced compared with applying 6.6 kV instantaneously, enabling restoration without causing an outage.

• Ground-fault detection

In Japan, distribution grids (typically 6.6 kV) have traditionally adopted an ungrounded (isolated-neutral) system, meaning that the system neutral is not intentionally connected to earth with an earthed voltage transformer (EVT) for zero-sequence voltage detection and a directional ground relay (DGR) are used in combination. Because the ground-fault current in an ungrounded system is extremely small, there are cases that the DGR does not operate.

On the other hand, when a ground fault occurs in the community microgrid, a potential issue is that the grid is separated from the EVT installed at the distribution substation, and the line-to-ground capacitance is small due to the short feeder length. As a result, the ground-fault current can be very small, and the DGR may not take closer a countermeasure, it was assumed that connecting an EVT and a grounding capacitor to the community microgrid's main power source would compensate the ground-fault current and enable tripping by the DGR. Based on this concept, a verification test of the ground-fault mitigation effect using an EVT and a grounding capacitor was conducted. The test results confirmed that the countermeasure equipment (EVT and grounding capacitor) enabled ground-fault detection and protection, and that protection coordination could also be achieved such that, in the event of a customer-side ground fault, the customer's incoming switchboard would trip.

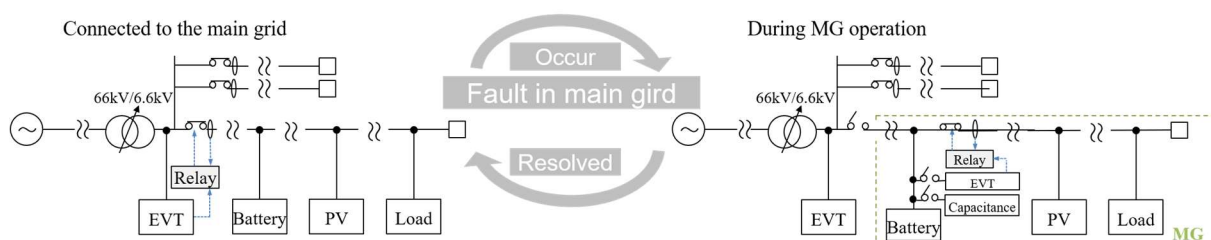


Figure 32. Image of Transition to Microgrid (MG) operation with EVT

• Short-circuit detection

When a short circuit occurs in the community microgrid, possible issues include:

1. a complete blackout due to operation of the main-source protective relay;
2. when a short circuit occurs within customer premises, the main source may stop before pole-mounted load break switch (recloser) lockout, causing the fault to occur again upon reclosing; and

3. because inverter-based sources provide smaller short-circuit current than rotating machines, only a current below the setting threshold for private recloser lockout may flow, making protection coordination difficult.

To address these issues, tests were conducted to examine a scheme in which (a) the main-source inverter is equipped with a function to limit overcurrent and continue operation during short-circuit events, and (b) a fault decision is made using a logic combining detection of the limited short-circuit current and detection of voltage depression caused by inverter current limiting. The test results confirmed that short-circuit detection and protection were achievable and that protection coordination with customer receiving equipment could also be achieved.

3.11.3. The application

The above countermeasures are currently being considered for implementation on-site.

3.11.4. The challenges

During the tests conducted to verify the effectiveness of the countermeasures, a considerable amount of time was required to develop the test plan and to coordinate with the relevant organisations. During the execution of the tests, unforeseen events occurred frequently. In each case, the tests were temporarily suspended, and countermeasures were discussed with the related organisations. Through repeated cycles of trial and error, including both failures and successes, the originally targeted results were ultimately achieved.

3.11.5. Recommendations for future users

When proposing new countermeasures, the most persuasive explanation is based on test results.

3.11.6. Steps for the full implementation

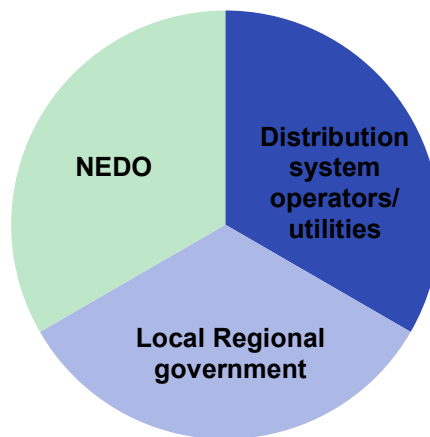
The above countermeasures are currently being considered for implementation on site.

3.11.7. How to measure the success of the innovation

For each countermeasure, the associated technical issues were thoroughly examined through tests and other verification activities. Based on these findings, desktop studies of the countermeasures were conducted in close coordination with the relevant organisations, followed by verification tests to confirm their effectiveness. As a result of this process, the effectiveness of the proposed countermeasures was successfully validated. (At present, some of the results are being reflected in relevant codes and guidelines in Japan.)

3.11.8. Actors contributing to the innovation

Which stakeholders contributed to the innovation?



3.12. Japan 3: Mitigating distribution grid congestion through flexible DER utilisation in Japan

Authors: Yuka Ogasawara, Renewable Energy Department, New Energy and Industrial Technology Development Organisation (NEDO); Tomoaki Minami, International Affairs Division, Commissioner's Secretariat, Agency for Natural Resources and Energy

Contributing authors: Naoki Kobayashi and Masato Watanabe, TEPCO Power Grid, Inc.

Phases addressed: strategic direction, development options, assessment and decision

3.12.1. The start

In Japan, a large share of PV generation consists of commercial-scale facilities (up to approximately 2,000 kW) that are interconnected in distribution grids. As reverse power flow from these facilities increases, congestion issues in distribution grids are becoming increasingly apparent. In particular, in distribution grids where curtailment is not implemented during periods of congestion of themselves, there has been a growing number of cases in which new interconnections cannot be realised unless network reinforcement is completed.

The Japanese Connect and Manage (chapter 3.10) mentioned before involves curtailment of power sources in the distribution grid as well when congestion occurs above the distribution grids, but capacity reinforcement is the only available option when the distribution grids become congested.

A key challenge to be addressed when establishing renewable energy as a main power source is how to achieve early interconnection without waiting for network reinforcement, while at the same time alleviating network congestion and promoting the effective utilisation of renewable energy, in parallel with the necessary infrastructure upgrades.

Therefore, if distributed energy resources (load) can be utilised when distribution substations are congested, it will be possible to reduce the cost of strengthening the grid and even the amount of renewable energy output that needs to be curtailed, so it has been decided to proceed with a NEDO project to achieve this⁵². This project conducted by ten partners with the leadership of three DSOs; the TEPCO Power grid, Chubu Electric Power Grid and Kansai Transmission and Distribution.

3.12.2. The innovation

The innovation is a “DER Flexibility System” that enables the sharing of grid congestion conditions and the utilisation status of DERs (such as the state of charge of batteries) and allows the control of DERs in accordance with the level of generation and load.

The “DER Flexibility System” is defined as an integrated set of the following systems and platforms:

1. a “General Transmission and Distribution Utility System” that issues DER control instructions in response to grid congestion conditions;
2. a “DER Flexibility Utilisation Platform,” which has market functions to enable transactions of DER flexibility between general transmission and distribution utilities and aggregators, as well as control functions to transmit control instructions to aggregators and other parties; and

⁵² NEDO Project: Development of Flexible and Distributed Energy Resources Control Technology to Mitigate Congestion in Power Systems (FLEX DER project) (JPNP22004)

- an “Aggregator System” that controls DERs based on the control instructions and manages their response status.

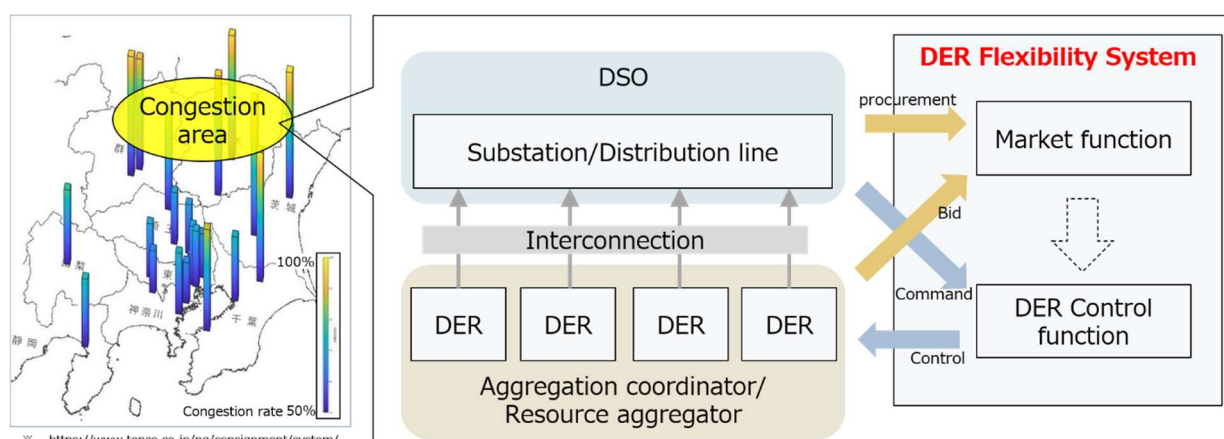


Figure 33. Image of DER Flexibility System

Aggregators register and bid DER flexibility information to the market functions of the DER Flexibility Utilisation Platform, while a DSO procures this flexibility. When grid congestion is anticipated, the DSO issues control commands to the control functions of the DER Flexibility Utilisation Platform, which then transmits the control instructions to the procured DERs via this function. It is predicted that congestion may occur at approximately 50 substations in the TEPCO Power grid, Chubu Electric Power Grid and Kansai Transmission and Distribution areas by 2030.

DER flexibility systems, based on the standard specifications established by the NEDO project, are expected to be gradually rolled out nationwide from around 2028.

3.12.3. The application

A case is assumed in which securing flexibility to address generation-driven congestion allows network reinforcement to be avoided or deferred. Several years in advance, when generation-driven congestion is forecasted and the use of flexibility is deemed to be more economically rational, flexibility is solicited and procured. Once sufficient volume has been secured, the flexibility is utilised during the period from the onset of congestion until the completion of network reinforcement.

It is also assumed that, if the expected flexibility proves insufficient immediately prior to the occurrence of congestion, additional flexibility will be procured.

3.12.4. The challenges

There were cases in which the views and comments between DSOs and aggregators did not align on recruitment requirements and control requirements.

It was suggested that stakeholder engagement is important in the deployment phase.

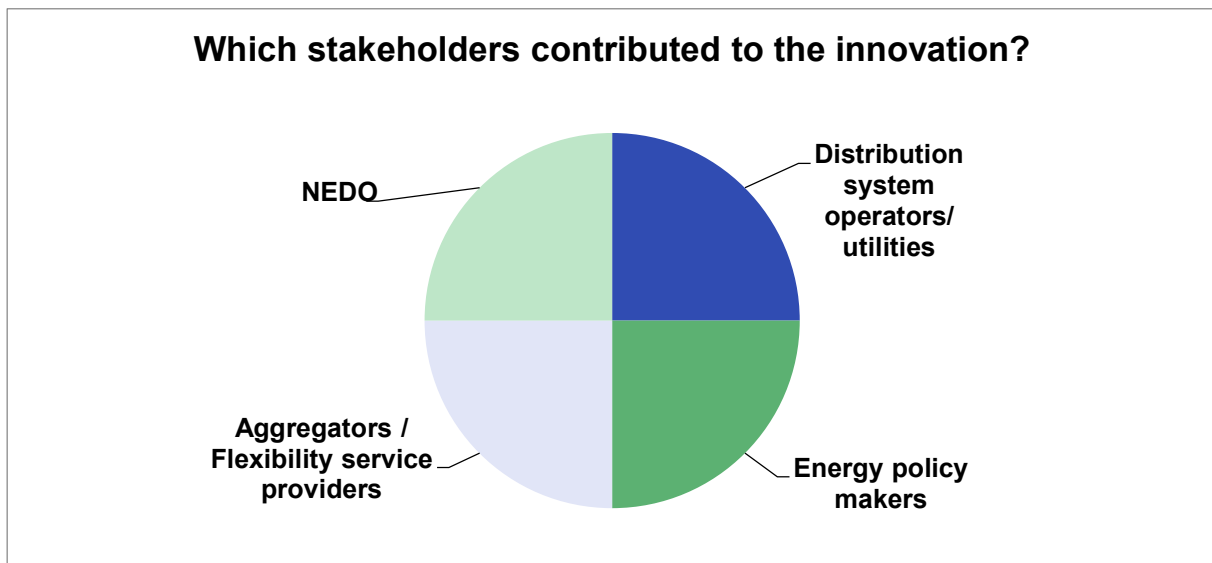
3.12.5. Recommendations for future users

There are likely to be other countries or regions facing similar challenges, and it is important to share lessons learned.

3.12.6. How to measure the success of the innovation

Although it has not yet been implemented, it is expected to significantly reduce reinforcement costs (several billion yen/year in three years by 2050) and accelerate renewables interconnection.

3.12.7. Actors contributing to the innovation



3.12.8. Next steps

To maximize the potential of DER flexibility, the DER Flexibility system will be linked to TSO grid operations towards simultaneous optimisation of kW and kWh. A feasibility study is currently underway as part of the NEDO Connect and Manage 2.0 project.

3.13. Spain: National regulatory sandbox for the electricity sector

Author: José Pablo Chaves

Contributing authors: Jorge Cano (ITE), Diego Garcia (Tecnalia), Mariano Gaudó (UFD)

Phases addressed: actor collaboration

3.13.1. The start

In March 2025, the Spanish government, through the Ministry for the Ecological Transition and Demographic Challenge (MITECO), published a list of five pilot projects selected for participation in the **national regulatory sandbox for the electricity sector**. This pioneering initiative provides a controlled environment for innovative pilot projects that require regulatory exemptions, with the ultimate goal of fostering regulatory innovation and supporting the energy transition. Among the five selected projects, S2F (“Flexibility Solutions in Distribution Networks”) stands out as the **flagship initiative for flexibility and active network management**, and benefits from dedicated financial support from the Ministry.

This regulatory push comes at a time when Spain’s distribution grid faces a paradox: according to the first official capacity maps published on 9 September 2025, 83.4% of network nodes are administratively saturated.⁵³ It is important to note that a significant portion of this saturation figure reflects capacity that is reserved but still in the administrative process, rather than physically utilised. In practice, the physical network is underutilised for most of the year, as the current system reserves capacity for each user as if all would use their contracted power simultaneously. This “nodal saturation” blocks new demand and renewable integration, highlighting the urgent need for more dynamic, flexible approaches to network management.

3.13.2. The innovation

Spanish regulation currently does not allow for flexible connections or local flexibility markets. S2F was conceived to provide the regulator with practical evidence and recommendations for developing the necessary regulatory framework to enable both. The project brings together Spain’s leading distribution companies, the Iberian Electricity Market Operator (OMIE), Comillas Pontifical University, and sector associations such as CIDE, ASEME, and AELEC, as well as technology providers, aggregators, and consumers.

S2F will run for up to two years and is about to commence, pending final approval of its detailed testing protocol. Around 28 pilot schemes (“demonstrators”) will be deployed nationwide, covering a wide range of network topologies, demand profiles, and distributed generation contexts.

A core innovation is the SIORD platform (Information System for Distribution Network Operators), a **national data exchange system connecting all stakeholders** in the distribution grid. SIORD enables advanced monitoring, control and coordination of distributed resources, and through its interoperability with OMIE’s market platform supports the development of local flexibility markets where consumers, producers and aggregators can offer and procure services according to network needs. Within this framework, S2F will **test flexible connections** that allow users to access the grid under variable conditions (for example, with restrictions during peak hours or temporary disconnections when network constraints arise) and the **operation of local flexibility markets** that enable demand and generation adjustment services to optimise capacity and system performance.

⁵³ <https://aelec.es/mapas-de-capacidad-saturacion-de-la-red>

3.13.3. The application

Demonstrators will be rolled out in diverse regions (including Galicia, Asturias, the Basque Country, Madrid, Catalonia, and others), ensuring a robust assessment of technical and regulatory barriers. The pilots are expected to demonstrate that new demand can be accommodated without requiring major network reinforcements, thus reducing renewable curtailment, and enhancing system resilience.

3.13.4. The challenges

Drawing on the “Challenges” document and sector analysis, the main barriers are:

- **Mismatch between electrification and network reinforcement:** Demand growth (from electric vehicles, heat pumps, data centres, hydrogen, batteries) is outpacing the network’s ability to accommodate new connections, leading to congestion and project delays.
- **Nodal saturation and inefficient allocation:** Administrative reservation of capacity blocks new projects, while the network is physically underused. There is a need for mechanisms that allow dynamic, real-time allocation of capacity and flexible access.
- **Legacy infrastructure and limited observability:** Much of the network was designed for one-way flows and lacks advanced monitoring, complicating the integration of distributed resources and dynamic management.
- **Technical complexity and cybersecurity:** Digitalisation introduces new risks related to stability, privacy, and data governance, with millions of connected devices.
- **Regulatory and investment barriers:** Current investment levels and remuneration methodologies do not sufficiently recognise the value of digitalisation and flexibility.
- **Fragmented planning and coordination:** Transmission planning is centralised and binding, while distribution planning is fragmented, causing misalignment and delays.
- **Access procedures and heterogeneous criteria:** Diverse criteria among operators and a lack of agile mechanisms to release capacity increase uncertainty and project lead times.

3.13.5. Recommendations for future users

- Move towards more efficient and flexible capacity management, specifying temporary timeframes for capacity use and penalties for unused allocations.
- Incentivise voluntary release of unused capacity and generalise flexible connections.
- Develop local flexibility markets and interoperable digital platforms to facilitate multi-actor participation and efficient flexibility management.
- Adapt the regulatory framework to recognise and reward flexibility services and digitalisation investments.

3.13.6. Steps for the full implementation

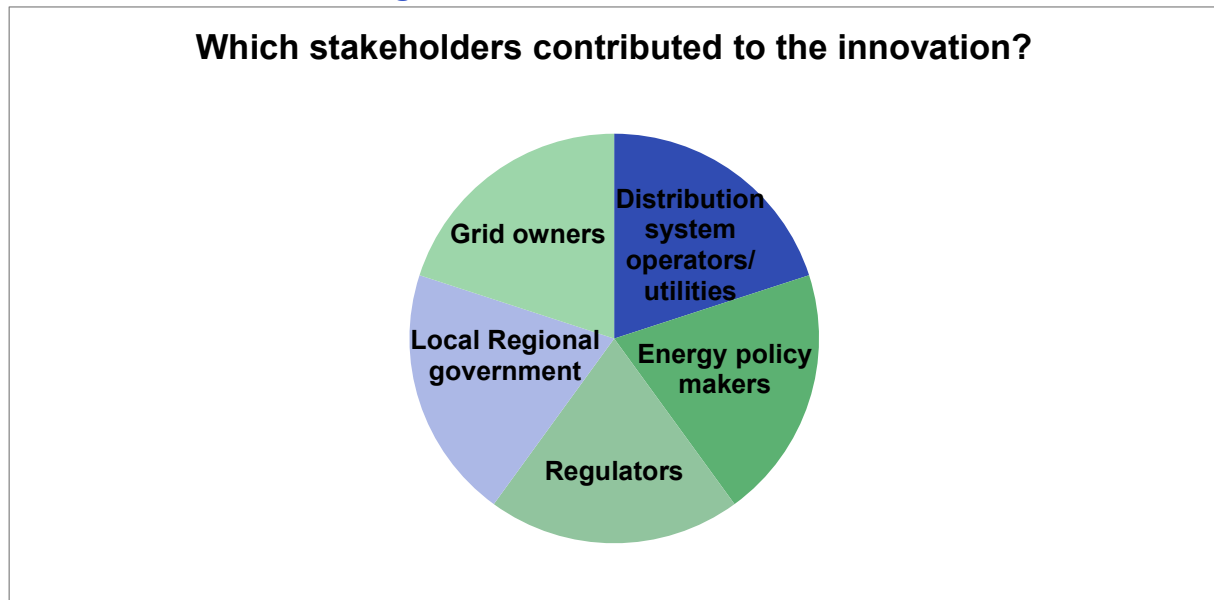
1. Complete the pilot phase and evaluate demonstrator results in terms of released capacity, efficiency, renewable integration, and demand participation.
2. Propose regulatory reforms based on evidence, including access procedures, flexibility remuneration, and data protection.
3. Scale successful solutions nationally, integrating learnings into distribution network planning and operation.
4. Foster interoperability and integration of digital platforms, ensuring coordination between SIORD and OMIE.
5. Continuously monitor and adjust the model, incorporating new technological and regulatory developments.

3.13.7. How to measure the success of the innovation

- Reduction in the percentage of saturated nodes and increased available capacity for new demand

- Number of pilots and stakeholders engaged in flexibility services
- Effective integration of renewables, self-consumption, and storage
- Active participation of demand and aggregators in local flexibility markets
- Degree of digitalisation and interoperability between platforms
- Improved efficiency, resilience, and service quality indicators
- Alignment with national and European energy transition and digitalisation objectives.

3.13.8. Actors contributing to the innovation



- Major Spanish distribution companies: UFD (Naturgy), i-DE (Iberdrola), E-Distribución (Endesa), E-Redes and Viesgo (EDP), Electra Caldense, Anell (Estabanell), Distribuidora Eléctrica Bermejales (Cuerva), Electra Conilense, Distribución Eléctrica Crevillent (Enercoop).
- OMIE (Iberian Electricity Market Operator)
- Comillas Pontifical University
- CIDE, ASEME, AELEC
- CNMC (National Commission on Markets and Competition), MITECO, IDAE (Institute for Energy Diversification and Saving)
- Technology providers, aggregators, consumers

3.13.9. New interactions

New interactions are needed to integrate the stakeholders. The regulator has working groups and also the Spanish association of Smart Grids (Futured).

3.13.10. Next steps

- Regulatory sandboxes are running, conclusions and drafting of proposed regulations based on the lessons learnt need to be performed.
- Challenges in scaling up in terms of customer engagement and ensuring enough liquidity to have competitive local markets
- Viable flexibility business models still need to be proven including the incentives to use flexibility.

3.14. Sweden 1: Innovative cooperation for local and regional long-term grid planning

Author: Susanne Ackeby (Research Institutes Sweden (RISE))

Contributing authors: Emil Hillberg (RISE), Helena Lindquist (LightSwitch)

Phases addressed: strategic foresight, strategic direction, development options, assessment and decision, implementation

3.14.1. The start

As in many other countries, Sweden is facing challenges in the long-term planning and implementation of a future sustainable electric power grid. These challenges relate, for example, to public acceptance of new grid infrastructure, uncertainties in the forecast demand and production for which future grids must be designed, and the long lead times from identifying a need to having a solution implemented and in operation. Long-term planning has always been a challenging task. However, with the ambition to utilize electrification as an enabler for reaching climate goals, driving a significant increase in demand and a need for new fossil-free production at a rapid pace, the challenge is even greater. In addition, the number of actors involved in today's power system has grown, and the system design has become increasingly advanced – two factors that further add to the complexity.

The motivations for establishing the collaboration platforms which this case is based on are:

Accelerate the green energy transition, strengthen local business development and contribute to a sustainable and robust energy system.

All regions where the platforms operate have faced risks of insufficient power grid capacity to meet forecast demand due to the electrification of industry and the transport sector. For some platforms, the need to increase local energy production is also a driver. One platform sees a specific need for collaboration regarding hydrogen, while for another, rising regional energy prices are a key motivation.

All platforms were initiated because the need for actor coordination and collaboration on energy-related issues was identified as critical for enabling the electrification required to meet climate goals, sustainable growth, and societal modernisation.

The **objectives** for the platforms are formulated differently, but the purposes are similar:

- Promote regional development
- Establish a collaboration platform that brings together relevant actors
- Increase knowledge and understanding of the energy transition from different perspectives
- Improve dialogue, increase consensus and identifying synergies
- Ensure a fair and sustainable energy transition
- Enable reliable forecasting of future regional needs
- Ensure that the electrical power system can meet the needs of the region
- Improve the electricity supply in terms of reliability, cost, and environmental impact
- Support regional goals for local energy production
- Shorten lead times for grid development
- Identify and implement solutions for flexible electricity use
- Strengthen security of supply for every hour of the year and increase resilience.

Figure 34. Collaboration platform objectives

3.14.2. The innovation

To accelerate and co-create better solutions for grid planning and grid implementation, several collaboration platforms have been established in different parts of Sweden in recent years. The description of the work within the Swedish collaboration platforms is based on a digital workshop held in October 2025, gathering representatives from five collaboration platforms presented in Figure 35.

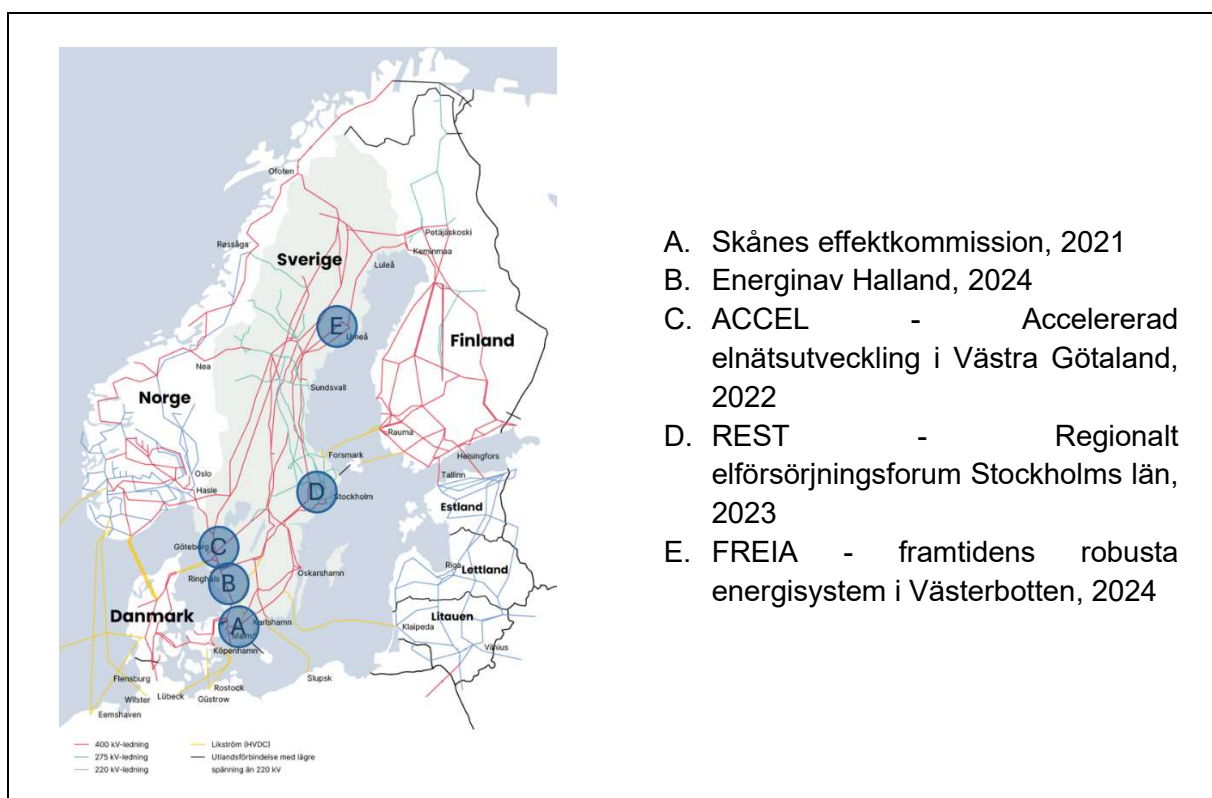


Figure 35. Map over the Nordic transmission grid (Illustration based on [Karta över transmissionsnätet | Svenska kraftnät](#))

Governance in Sweden operates at three levels: national, regional, and local. Laws and regulations guiding the energy sector are set at the national level. The government and government agencies provide some steering to encourage increased regional coordination and collaboration at the regional level, for example, mandating each county to develop regional plans for electrification.

Each of the 21 counties has two governmental bodies at the regional level, with partly overlapping competences regarding energy issues:

The County Administrative Board (Länsstyrelsen): a government authority responsible for implementing national objectives while considering regional conditions, coordinating societal interests, managing regional planning, and granting environmental permits for new infrastructure. The leadership of the County administrative boards is appointed by the Swedish government.

The County Council (Regionen): a self-governing body responsible, among other tasks, for promoting regional growth and sustainable development. Its leadership consists of elected politicians representing the region's residents. The County Council shall ensure good welfare and quality of life for its citizens, which is why it has a strong interest in promoting favourable conditions for new and existing businesses, such as available grid capacity and competitive electricity prices.

At the local level, Sweden is governed by 290 self-governing municipalities responsible for most public services. The **collaboration platforms for long-term planning** of the electricity system are usually jointly managed by the County Council and the County Administrative Board. Some platforms were jointly initiated, while others originated from the County Council. All platforms include one or more grid operators (in Sweden the grid operators also own their grids). Since there are often many municipalities within each region, they are invited to specific meetings or, in some cases, represented by selected municipality representatives. Some platforms also involve actors such as energy producers, industry stakeholders, NGOs and academia.

The platforms are often organised in multiple layers or subgroups. Some have received governmental funding within time-limited projects, while others are financed through the participating organisation's operational budgets.

Example: FREIA collaboration platform, Västerbotten Region

- The central forum meets four times a year.
- A secretariat manages the operational work.
- Specific focus groups are established for strategic collaboration on:
 - hydrogen,
 - the power grid,
 - energy planning.
- Other activities such as dialogue meetings, panel sessions, conferences etc. are initiated based on identified needs.

Figure 36. Brief example of how one of the collaboration platforms (FREIA) is organised

3.14.3. The application

There are no requirements or formalised structure for collaboration platforms on power system development; therefore, the collaborations were bottom-up initiatives based on identified needs. The setup and objectives may therefore differ slightly between the platforms, but there are several similarities.

3.14.4. The challenges

Although many aspects function effectively within the collaboration platforms, challenges remain. The challenges expressed by platform representatives are grouped into three categories:

Involving the right and sufficient resources

- participating actors have different capabilities and mandates
- finding the right balance in actor involvement – engaging all relevant actors while keeping the group size manageable
- securing resources to strengthen process leadership in the working groups
- reducing vulnerability when engagement is tied to specific individuals.

Joint view and clear communication despite conflicts of objectives

- identifying conflicting objectives among participating actors
- creating a shared understanding of the problem
- communicating a common vision despite a lack of full consensus
- communicating objectively and in a fact-based manner, avoiding political statements.

Turning words into action

- achieving “Less talk, more action”
 - enabling actors to prioritise the work
 - promoting cooperation towards concrete problem-solving
- ensuring focus by e.g., separating cooperation regarding short-term and long-term perspectives
 - one forum for enabling physical infrastructure projects (short-term)
 - another forum for long-term energy system design, where shared knowledge enables exploration of long-term opportunities.

3.14.5. Recommendations for future users

Several learnings can be drawn from the Swedish collaboration platforms. The collaboration platforms have experienced many positive outcomes that pave the way for more efficient grid development based on better and more well-anchored solutions, for example:

- increased understanding of system complexity and other actors' perspectives
- improved internal engagement and anchoring
- shortened communication paths through increased interaction
- early identification of conflicting objectives.

3.14.6. Steps for the full implementation

The approach is already in use.

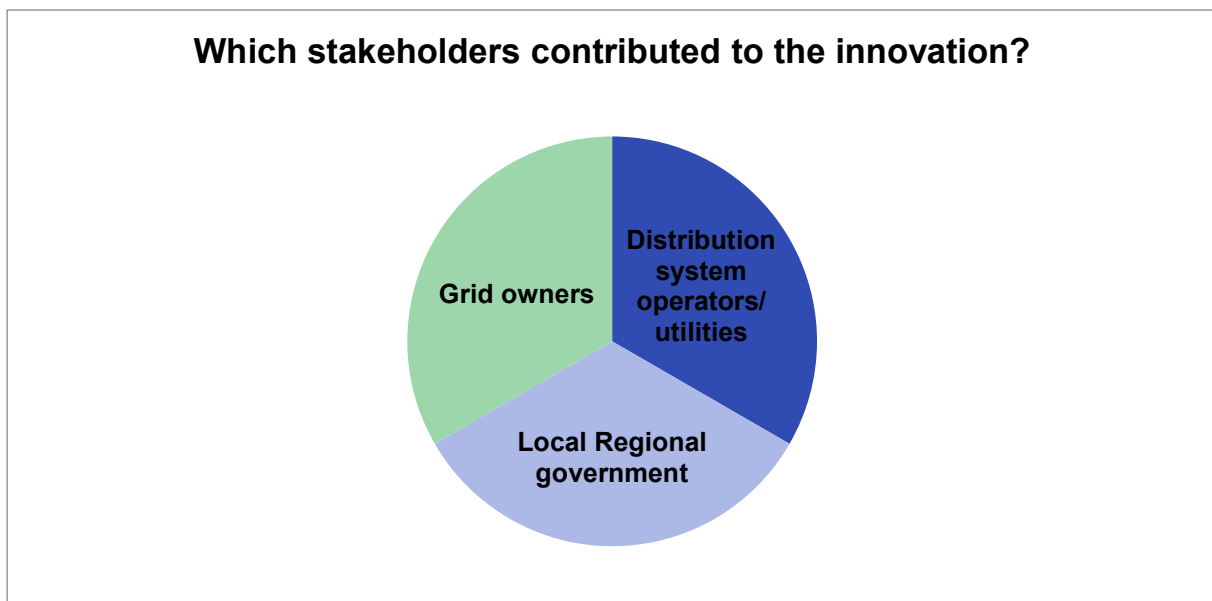
3.14.7. How to measure the success of the innovation

Participants highlight that many aspects work well, including collaboration between involved parties, agile and efficient administration, strong management anchoring and a shared understanding of the platform's purpose. Figure 37 presents some success factors identified by the platform representatives.

- Agree on (and build a shared understanding of) common challenges, what you wish to communicate, and what you want to achieve.
- Establish an agreement on common starting points and ways of collaborating. Clarify what the participating actors are committing to.
- It is important to take responsibility and work together. Don't just sit and wait for someone else to act!
- Building a collaboration platform takes time, for example allocating resources for coordination, preparation, and process management.
- You don't need to have all the answers from the beginning. It is also about the process of finding answers together.

Figure 37. Success factors identified by the collaboration platform participants.

3.14.8. Actors contributing to the innovation



The local and regional government, distributions system operators, utilities and grid owners contributed to this innovation. Some platforms also involve actors such as energy producers, industry stakeholders, NGOs, and academia.

3.15. Sweden 2: Collaboration Platform in Skåne Region

Author: Susanne Ackeby (Research Institutes Sweden (RISE))

Contributing authors: Emil Hillberg (RISE), Helena Lindquist (LightSwitch), Johanna Lundström (Region Skåne), Jonathan Rodriguez Polit (Swedish Energy Agency)

Phases addressed: strategic foresight, strategic direction, development options, assessment and decision, implementation

3.15.1. The start

Grid capacity constraints pinpointed a need for collaboration focusing on the future regional electricity supply. Region Skåne (a self-governing regional entity) initiated the collaboration platform and has a leading operational role.

3.15.2. The innovation

A new collaboration platform bringing together regional actors with the ability to jointly create the right conditions to enable the electrification was needed for the climate, sustainable growth, and societal modernisation.

The **collaboration platform** involves several different actors including **Region Skåne**, the county administrative board (Länsstyrelsen), governments of the largest municipalities in the region, the largest local grid operators (in Sweden the grid operators also own their grid), power producers, and representatives for the industries.

A group of high-level representatives from each involved organisation runs the collaboration platform, with support for practical operations and administrative issues. The work is guided by a roadmap for 2030, including a clear joint vision, identified needs, and suggestions on how to bridge the gaps. Based on the identified needs, dedicated focus groups have been formed and populated according to their specific topics. The focus groups are divided in three sub tracks: demand (new ways of working, regional flexible resources); distribution (connect and manage; efficient grid development together; plans and forecasts; territorial availability; regional grid collaboration); supply (repowering wind; offshore wind; combined heat and power; new onshore wind; gas turbines). The organisational chart of the Skåne Power Commission is shown in Figure 38.

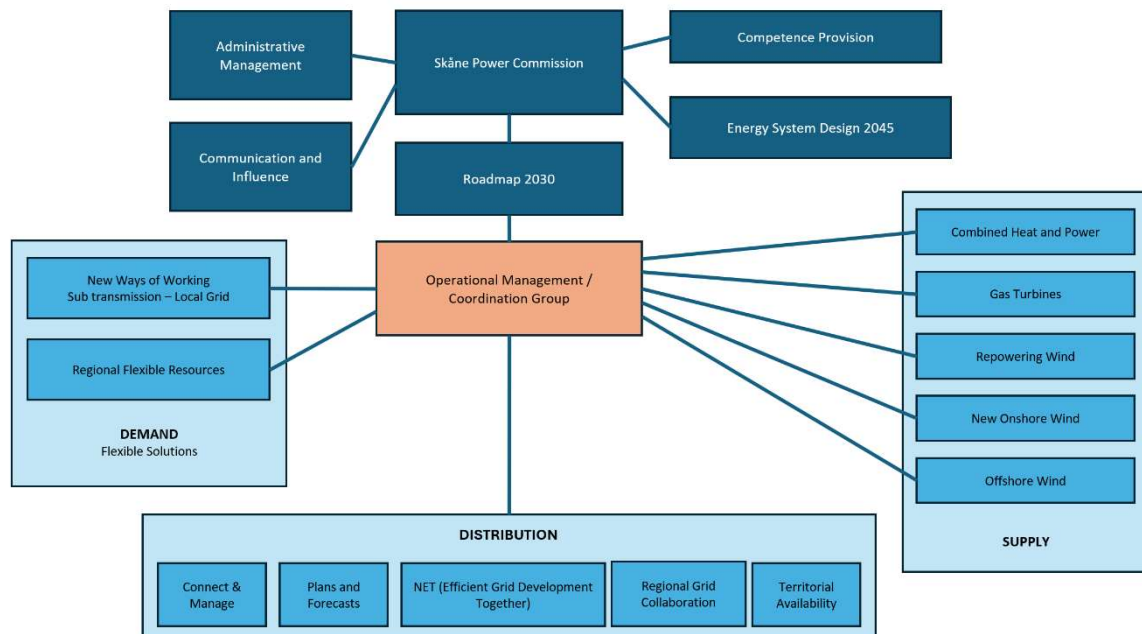


Figure 38. Skåne Power Commission

3.15.3. The application

The collaboration has been active since 2021.

3.15.4. The challenges

The collaborative work has overall developed very well, as all actors are engaged and realize the importance of what the platform aims to achieve, and they therefore fully support the joint vision. However, as in all collaborations, there are challenges, including how to best share information and ensure unified and clear communication.

Due to changes in political priorities on the national level, the roadmap for 2030 had to be revised. The joint vision helped in reformulating a new adapted roadmap.

3.15.5. Recommendations for future users

Formulating a joint vision of what the collaboration platform aims to achieve and involving actors that are engaged and aligned with that vision is key. Shared responsibility among involved actors in leading the focus groups, based on who is best suited, ensures good results and helps manage the workload. Having a solid mandate and supportive leadership in the involved organisations enables operative platform members to commit to and prioritise the joint work. The importance of building a strong yet flexible collaboration structure, as well as investing in developing the collaboration culture (including building trust amongst members from different organisations), should not be underestimated.

3.15.6. Steps for the full implementation

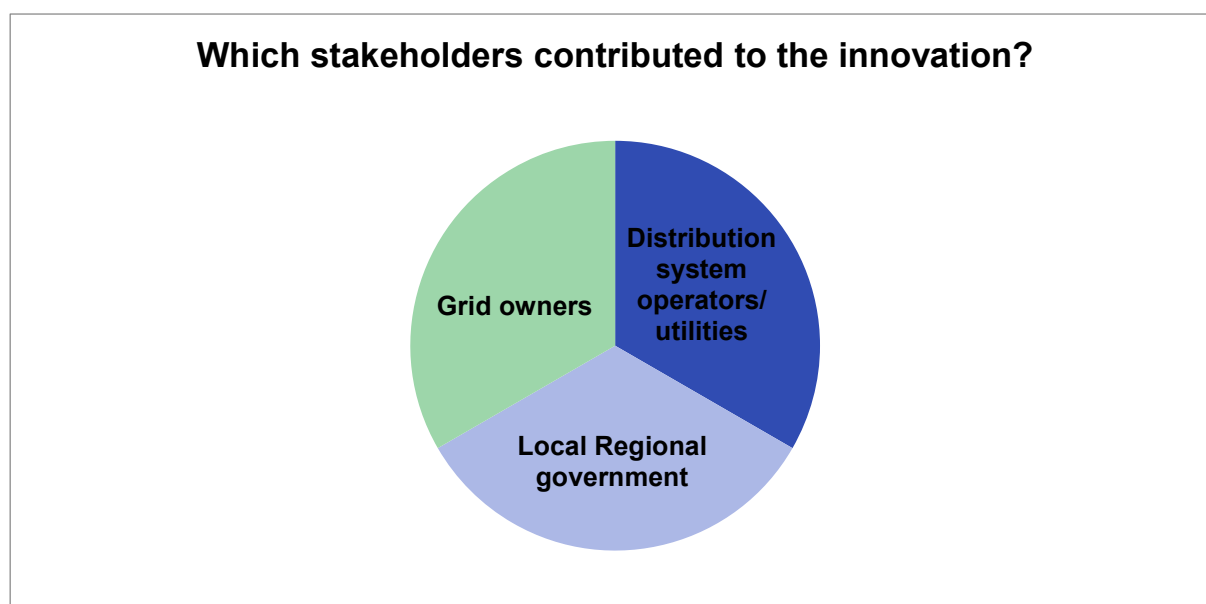
The complexity of the topics considered in the collaboration platform is a major challenge. For example, there are many actors involved and impacted, as well as the fact that other actors (e.g. at the national level) may hold the authority or mandate to act on issues the platform aims to address.

The collaboration platform has worked well and has gained importance within the involved organisations. It was created in response to an acute situation of high priority to all participating actors, who therefore committed considerable resources to the joint work. It is unknown whether the same level of collaboration would have been achieved in a less urgent situation. Therefore, it is vital that the roles and responsibilities for national and regional energy system design are clearly defined, communicated, and monitored. It is also important that failure to fulfil the responsibilities leads to consequences, to ensure the work remains a priority.

3.15.7. How to measure the success of the innovation

One key achievement is the creation of a common problem description, enabling a shared understanding of what is needed, followed by a common roadmap for how the challenges should be managed. The collaboration platform has also helped highlight the importance of the issues and thereby increased their priority. For example, the work of the collaboration platform was one important factor in a political decision to abandon plans to decommission a local combined heat and power plant, which would have reduced the region's energy self-sufficiency. The platform has also facilitated better communication between the involved actors, enabling more efficient work.

3.15.8. Actors contributing to the innovation



Changes in the roles of actors

Focus groups and priorities have changed over time, but the core group of participating organisations has remained consistent. Each participating organisation has continuously ensured, and if needed, revised its representation in the focus groups.

The work within the collaboration platform has developed over time as new needs have been identified. For example, a new focus group has been formed to focus on collaboration between sub-transmission grid operators/owners and distribution grid operators/owners. Another group has been formed focusing on long-term energy system design (2045). As platform participants have worked together on the identified issues and come to know each other better, interaction within the platform has improved. This improved interaction has led to greater transparency, better communication, and improved understanding, all of which benefit co-creation and efficiency.

Interaction within the actor groups:

At the start of the collaboration platform, the highest level in each organisation was engaged – CEOs, chairpersons of municipal executive committees, chairpersons of regional development committees, the county governor (Landshövding), etc. These individuals then appointed participants from their own organisation to the working groups (responsible officials, planners, developers, etc.). Other stakeholders not actively involved in the collaboration may be invited to join specific focus groups if considered beneficial. Meetings with local politicians have been arranged, where they meet representatives from the collaboration platform, including the regional government, the county administrative board, and regional and transmission system operators (owners). These meetings provide a forum to discuss and raise questions, and where local politicians can receive more information about upcoming decisions, such as plans for future grid infrastructure. The collaboration platform also arranges workshops and similar activities to reach a wider audience.

3.15.9. Next steps

The collaboration platform will continue its work. The focus groups and their activities are continuously developed to align with the most critical aspects needed to achieve the vision.

3.16. Switzerland: Framework for target network planning

Author: Alexander Fuchs (Research Centre for Energy Networks, ETH Zurich)

Contributing authors: C. Yaman Evrenosoglu, Adamantios Marinakis, and Turhan Demiray (Research Centre for Energy Networks, ETH Zurich)

Phase addressed: development options

3.16.1. The start

The project(s) started with the electric distribution utilities expressing their need to identify the type and amount of end-user flexibilities under future energy scenarios with increasing electrification of mobility and heating and increasing proliferation of distributed solar photovoltaic (PV). Assumptions were made such that individual goals (“own consumption”) of the end-users who own distributed energy resources were aligned with the goals of distribution network operators (“reduction of bottlenecks”).

As part of the project(s) the needs of utilities (e.g., operational practice, planning practices, demand and generation evolution in their services territories in the next one and two decades) were surveyed. The project steps included regionalisation of energy scenario and bottom-up modelling, implementation of a target network simulation in a flexible environment, and synthesis of recommendations to utilities.

3.16.2. The innovation

The innovation consists of a **framework for target network planning** with two pillars illustrated in the overall framework in Figure 39:

1. Regionalisation of national scenarios and time-series creation at the building level
2. Grid planning analysis to identify the grid upgrades and to calculate the investment costs.

As part of the first pillar, regionalisation of national scenarios, the target adoption values for production PV, heat pumps (HP), battery energy storage systems (BESS), and electric vehicle (EV) charging are reflected to the service territory of the utility. Following, federal databases are used to extract the building characteristics (e.g., type of building, number of floors, building area, age, rooftop area etc.) for each building in the service territory of the utility. This information is used to estimate the installed capacities of PV, HP, BESS and EV charging infrastructure per building and used to create the time-series of net electricity demand at each node of the electricity grid. There are established groups at ETH Zürich (PSL and FEN), EPFL (DESL), EBP and EMPA in Switzerland to perform all or parts of this pillar.

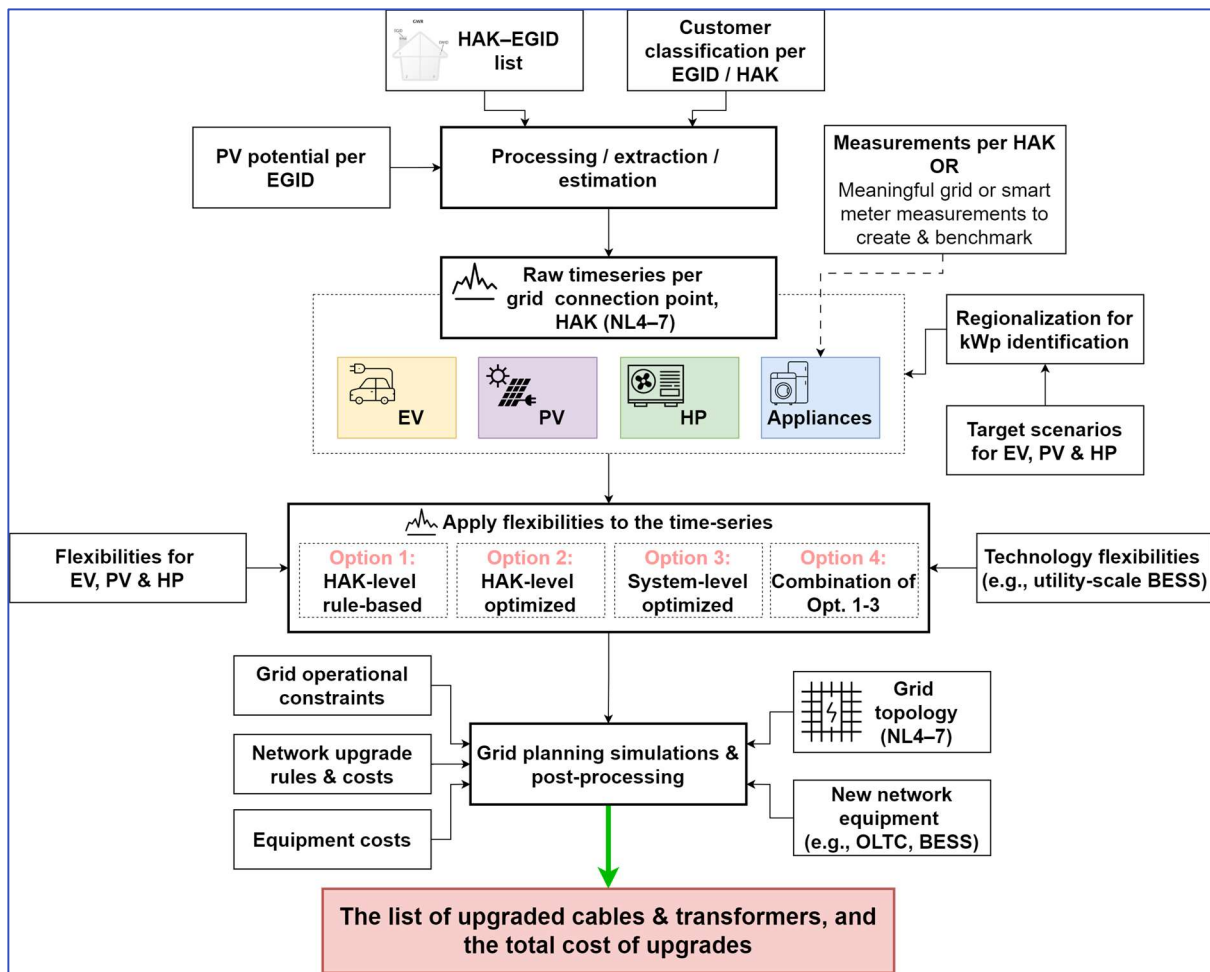


Figure 39. Overall framework with two pillars: (i) Regionalisation of scenarios and bottom-up modelling, (ii) grid planning framework. EGID: Federal building identification number, HAK: Hausanschlusskasten – grid connection point

As part of the second pillar, first, the network data in the format of the commercial software used by utility (e.g., Neplan, PowerFactory, CYME, Integral) are converted to the input format for the in-house FEN tool, FlexDYN. All grid models include the grid topology with all branch elements (cables, overhead lines, transformers) and all connection points at which loads and generation systems are connected to the grid. The connection points used in the grid planning studies are directly the HAKs (i.e., grid connection point, Hausanschlusskasten), each with a unique identifier (HAK ID), and are modelled in the grid model as a load or as a feed-in.

In the original grid model, each customer/building is assigned to a HAK number with an active and reactive power pair. For each customer/building, the values for active and reactive power correspond to an aggregation of the electricity demand (i.e., net demand). In the distribution grid planning framework, the types of loads are represented individually at the HAK level so that specific measures for a load type, such as PV curtailment, smart operation of HPs or smart charging of EVs, can be mapped and applied individually per HAK. For this purpose, each HAK that is represented in the original grid model by an aggregated load is replaced by several load types such as electrical appliances (i.e., conventional demand), HPs, electromobility (EV charging), and solar PVs in order to be able to assign the individual profiles for each load/generation type one-to-one to the grid model.

Operation rules are selected by the utilities in terms of allowable loading for cables and transformers in NL4- 7 (e.g., 100% for NL6 and NL7, 70% for NL4-5) and allowable voltage deviations. The grid expansion is performed for each target year by using today's grid, instead of using the results of the previous target year.

Once the PV and demand profiles for each target year are created, they are assigned to the grid nodes per substation. AC load flow analyses are performed using these generation and demand profiles. The thermal overloads and voltage violations are identified, and the grid expansion requirements are determined based on conventional/traditional and NOVA principles (i.e., grid optimisation before grid reinforcement before grid expansion).

In conventional/traditional grid expansion, cables, lines and transformers are reinforced so that the grid can accommodate the power peaks on the demand and/or supply side. Over the course of the year, these power peaks only occur in a few hours. Nevertheless, the grid is dimensioned for these power peaks. With the NOVA principles, other measures such as PV feed-in management or demand-side management are adopted to reduce these power peaks without any loss of comfort on the demand side. These measures can avoid, reduce or delay the need for grid expansion.

The following measures are considered as part of **traditional planning** due to **overloads**:

- cable reinforcement by adding parallel cables
- cable expansion by increasing the cross-sectional area
- burying overhead lines, replacing them with underground cables
- transformer reinforcement by adding parallel transformer(s)
- transformer expansion by increasing the transformer capacity

The following measures are considered as part of **traditional planning** due to **voltage violations**:

- addition of parallel cables
- medium voltage (MV) grid expansion is performed first, and low voltage (LV) grid expansion performed later
- LV grid expansion is performed first, and MV grid expansion performed later

Transformer settings: It is important to note that the rated voltage values of the MV-LV transformers are sometimes adjusted by the utilities to be higher than the nominal voltage of the nodes in the LV grids. This is a practice adopted by most utilities to ensure that the voltages are within the limits during times of high demand, **avoiding undervoltage violations**. In various studies with the utilities, it was decided not to adhere to this practice and select the rated voltage as the nominal voltage of the nodes because the expected type of voltage violations in the future with very high PV penetration is expected to be “**overvoltage violations**” and these violations will be due to the excess PV production. Therefore, the practice of adjusting the rated voltage of the transformers to values higher than nominal voltages must be revisited in the future with high PV proliferation, and the grid planning framework is envisioned to be neutral to different practices adopted in the industry. As a first step in the grid planning framework, the rated voltages of the secondary side of the MV-LV transformers are set to be equal to the nominal voltage of the nodes in the low voltage grids.

The following **NOVA** measures are considered for grid planning in addition to traditional measures:

- **Q(U):** All PVs are assumed to be providing reactive support according to selected Q(U) characteristics.

- **OLTC and VRDT:** The on-load tap-changing HV-MV (NL4) and MV-LV (NL6) transformers (also known as voltage-regulation distribution transformers) are assumed to be capable of operating with respect to V(P) characteristics.
- **Flexibility:** PV curtailment, limiting the HP operation by reducing the peak or shifting the operation by +/- minutes, smart EV charging (e.g., delaying the residential charging to take place at night, coordinating the workplace charging to take place during high PV hours), limiting the charging capacity.

The grid planning variations are performed for each substation for the reference scenario and for each target year selected by the utility.

Finally, grid investment costs (CAPEX) are calculated considering the unit costs of each component that is selected from an asset library. Annualised costs are also calculated using, a discount rate (WACC), lifetime of each component, and operation and maintenance costs for each component (OPEX). Substation and building costs as well as digging (trench) costs are taken into account.

3.16.3. The application

The new tool is currently being applied in theoretical studies to demonstrate the impact of various flexibility approaches on the target distribution grid. Additionally, it is being used in practical studies for the planning of real distribution grids. These applications help bridge the gap between theory and real-world implementation.

3.16.4. The challenges

The main challenges were to estimate a realistic flexibility potential. Another key challenge was to estimate realistic future net-demand time series under conditions of uncertainty. Together, these tasks required careful consideration of both technical constraints and uncertain future developments.

3.16.5. Recommendations for future users

It is recommended to closely interact with all participants (e.g., DSOs, end-users) and identify what are hard constraints and what are negotiable objectives. Furthermore, it is important to point out where the different objectives are aligned.

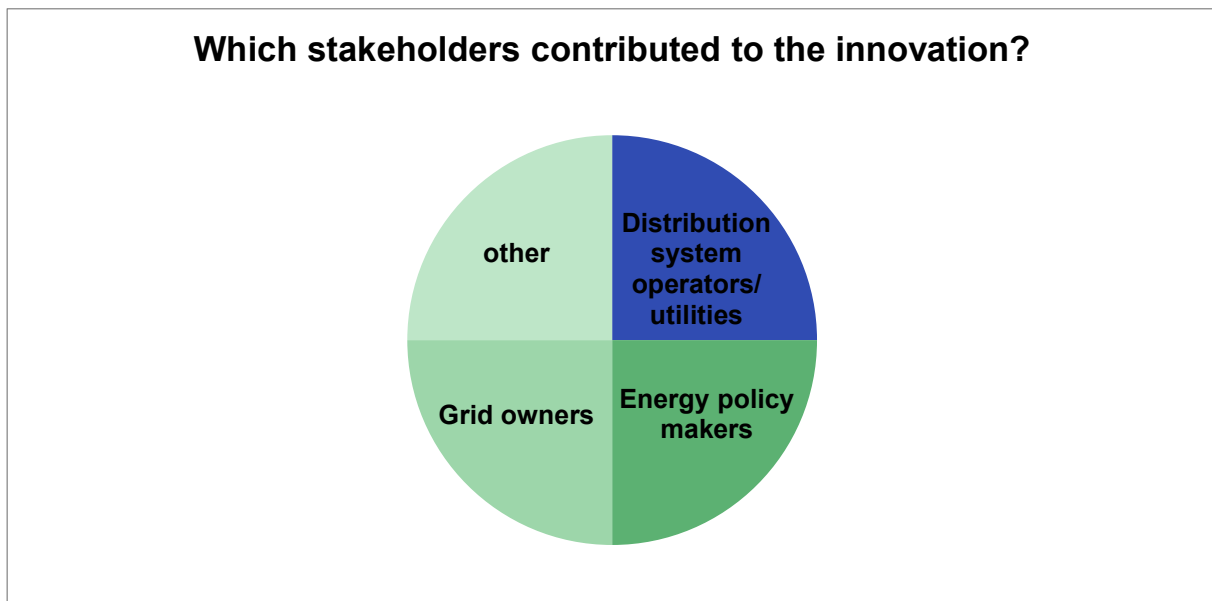
3.16.6. Steps for the full implementation

What is still missing: (i) mechanisms (e.g., long-term contracts) enabling utilities to rely on end-user flexibilities in their infrastructure planning processes, (ii) frameworks for reliable activation of the available customer demand flexibility, for example through home EMS receiving signals from the DSO.

3.16.7. How to measure the success of the innovation

The innovation is considered a success when it is accepted for industry planning purposes.

3.16.8. Actors contributing to the innovation



The roles of the involved stakeholders remained unchanged following the introduction of the new tool. However, a broader perspective is now adopted, with greater consideration for the roles and interests of other stakeholders (e.g., social equity in grid tariffs). Additionally, collaborative workshops have been conducted, particularly when the objectives of stakeholders diverge, which has proven to be highly beneficial for critically assessing the methodology. Throughout the project development, various methods were employed to engage with stakeholder groups, including joint workshops, Steering Committee (SteCo) meetings, and individual bilateral exchanges.

3.16.9. Next steps

Work is ongoing to develop a proof of concept that shows how customer flexibility can be activated reliably at a global scale.

Scaling this approach up comes with many challenges. One technical challenge is establishing a robust interface and communication pathway between DSOs and customers, especially because not all smart meters support the required functionality. An organisational challenge is that using flexibility can disrupt traditional DSO grid operations, since power flows become more volatile and bidirectional and operators must carry out more frequent control actions. A social challenge is ensuring public acceptance of flexibility measures within the electricity supply.

4. Appendix A: Questionnaire Template

E-mail
Name
Which country do you represent?
Who is the main national casebook author? Name and affiliation.
Who are contributing authors? Name and affiliation.
How did the project/initiative start? What initiated the change? What was the problem/challenge to be solved (use case)?
What was the types or categories of problem the project aimed to solve? Select all that apply.
Which stakeholders or target groups need or will benefit from this innovation?
What role did your management or leadership team play in initiating and driving the innovation?
What new tools / processes have been developed or implemented? Please provide a detailed description
Are the tools or processes used?
Explain why/how they are used.
What challenges did you encounter during the process? What lessons did you learn including any setbacks or things that did not go as planned?
What recommendations would you give to others looking to implement similar innovations?
What is still missing for full implementation? What barriers / hindrances exist?
Why do you consider that the implementation of the presented innovative approach can be considered a success: are there any KPIs or concrete data evaluated?
Which actors contributed to the innovation?
Did the roles of actors need to change through the process? Were new roles created?
Did the interaction between actors change? Were new processes necessary?
How did you engage with the relevant actor groups during the development and implementation phases?
Next steps: Are there plans for further developments of the innovation?
Are there challenges in scaling up the innovation?
Any other comment you would like to make to help others implement such changes?
As a classification tool the following framework is used in the casebook. Please make the best estimation in which phase of the smart grid planning phases your innovation fits best.

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