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ENTSO-E TYNDP 2026 - Identification of System Needs Methodology

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From:

ENTSO-E Planning Study Team

System Development Committee

ENTSO-E Mission Statement

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the association of the European transmission system operators (TSOs). The 40 member TSOs, representing 36 countries, are responsible for the secure and coordinated operation of Europe's electricity system, the largest interconnected electrical grid in the world.

Before ENTSO-E was established in 2009, there was a long history of cooperation among European transmission operators, dating back to the creation of the electrical synchronous areas and interconnections which were established in the 1950s.

In its present form, ENTSO-E was founded to fulfil the common mission of the European TSO community: to power our society. At its core, European consumers rely upon a secure and efficient electricity system. Our electricity transmission grid, and its secure operation, is the backbone of the power system, thereby supporting the vitality of our society. ENTSO-E was created to ensure the efficiency and security of the pan-European interconnected power system across all time frames within the internal energy market and its extension to the interconnected countries.

ENTSO-E is working to secure a carbon-neutral future. The transition is a shared political objective throughout the continent and necessitates a much more electrified economy where sustainable, efficient and secure electricity becomes even more important. Our Vision: "a power system for a carbon-neutral Europe" shows that this is within our reach, but additional work is necessary to make it a reality.

In its Strategic Roadmap presented in 2024, ENTSO-E has organised its activities around two interlinked pillars, reflecting this dual role:

- "Prepare for the future" to organise a power system for a carbon-neutral Europe; and
- "Manage the present" to ensure a secure and efficient power system for Europe.

ENTSO-E is ready to meet the ambitions of Net Zero, the challenges of today and those of the future for the benefit of consumers, by working together with all stakeholders and policymakers.

Contents

Executive summary

The Identification of System Needs (IoSN) methodology for the ENTSO-E TYNDP 2026 defines the analytical framework used to identify where additional electricity transmission and storage infrastructure can bring value to the future European power system. It supports ENTSO-E's legal mandate under Regulation (EU) 2022/869 by providing a transparent, coordinated, and system-wide assessment of pan-European infrastructure needs for the 2035, 2040, and 2050 horizons. The methodology does not prescribe investment decisions; instead, it identifies cost-efficient and technically robust opportunities for system development that support renewable integration, security of supply, and the functioning of the internal electricity market.

At its core, the methodology applies a pan-European expansion optimisation of the electricity system, complemented by an explicit representation of the hydrogen system. Electricity network and storage investments are optimised to minimise total system costs, while the hydrogen network is modelled as an exogenous but operationally optimised system, allowing the analysis to capture cross-sector interactions through electrolysers, storage, and hydrogen demand. This integrated approach reflects the growing role of sector coupling in Europe's decarbonised energy system and ensures that electricity infrastructure needs are assessed in a broader system context.

A key methodological evolution in TYNDP 2026 is the systematic treatment of climate uncertainty. For each target year, the expansion optimisation is performed across three representative weather scenarios derived from the Pan-European Climate Database using a structured statistical selection process. These scenarios capture diverse and realistic climatic conditions affecting demand, renewable generation, and hydropower availability. By applying a robust optimisation framework that accounts for weather scenario variabilities, the methodology identifies infrastructure developments that perform well across a range of future weather conditions, strengthening the resilience and credibility of the results.

The spatial representation of the power system is also significantly enhanced. Rather than relying on a single-node-per-country or Net Transfer Capacity (NTC) approach, the methodology uses an advanced zonal clustering and network reduction process. Around one hundred zones are defined across Europe, preserving key structural bottlenecks and internal constraints while maintaining computational tractability. This zonal model enables a more realistic representation of physical power flows, internal congestion patterns, and the interaction between onshore and offshore grids, improving the identification of cross-border and offshore system needs.

Offshore system development is fully integrated into the framework. National non-binding offshore renewable energy targets are taken as fixed inputs, and the methodology explores onshore cross-border developments, offshore interconnections, and hybrid corridor options in a unified optimisation. Environmental protection requirements and other uses of the sea are considered through simplified but consistent assumptions, ensuring comparability across sea basins while avoiding false precision where data are uncertain or incomplete.

The optimisation is performed separately for each target year using a multi-step investment modelling approach. An initial step focuses on real, TSO-proposed investment candidates, followed by a second step that includes conceptual and theoretical offshore corridors options; Storage candidates are considered as well. This structure balances transparency, realism, and computational

efficiency, while post-processing ensures that the resulting portfolios are technically meaningful and economically relevant.

Overall, the TYNDP 2026 IoSN methodology represents a substantial evolution compared to previous cycles. The explicit integration of the hydrogen system, the use of robust optimisation across multiple weather scenarios, the consistent application of zonal modelling across all horizons, and the unified treatment of onshore and offshore planning together provide a more realistic, resilient, and decision-relevant assessment of Europe's future electricity infrastructure needs. The methodology forms the analytical foundation for the TYNDP 2026 Infrastructure Gaps Report and ONDPs, supporting policymakers, regulators, TSOs, and stakeholders in understanding where strategic grid development can most effectively support Europe's energy transition.

1. Introduction

The pan-European Ten-Year Network Development Plan (TYNDP) is a cornerstone in Europe's coordinated development of electricity infrastructure. As part of the TYNDP, the Identification of System Needs (IoSN) is a comprehensive, scenario-based analysis established to identify infrastructure needs and cross-border enhancement opportunities for the European power system across the 2035, 2040, and 2050 horizons. The scope of the IoSN expansion optimisation covers electricity transmission infrastructures and electricity storage infrastructures, and it is designed to transparently demonstrate cross-border electricity transmission infrastructure development opportunities on a pan-European level, storage capacities needs, and offshore corridors, through a harmonised and integrated optimisation approach. Developing the IoSN is part of the legal mandate of European Network of Transmission System Operators for Electricity (ENTSO-E) under Regulation (EU) 2022/869.

This methodology provides the foundation for the IoSN: it outlines the analytical framework and tools used to assess the ability of the grid to meet future demand, integrate renewable energy sources, and facilitate the development of a harmonised internal electricity market in a cost-effective manner.

It incorporates enhanced modelling techniques, stakeholder inputs, and methodological evolutions compared to prior editions - most notably TYNDP 2024 Identification of System Needs Implementation Guidelines and the Offshore Network Development Plan (ONDP) 2024 Methodology.

The methodology integrates both onshore and offshore system perspectives and accounts for the expected electrolyser deployment, hydrogen infrastructure, energy storage, and an advanced zonal clustering method allowing more granular representation of the electricity system.

Key Elements of the Methodology

- Multisector Integration: Modelling of the electricity system alongside the hydrogen system, including storage in both sectors and cross-sectorial coupling through electrolysers.

- Temporal Scope: Three target years - 2035, 2040, and 2050 - are assessed to evaluate the evolution of needs under evolving scenarios and European climate targets.

- Scenario Framework: Built upon the latest Pan-European Climate Database (PECD), Pan-European Market Modelling Database (PEMMDB) market data sets, and assumptions aligned with the joint[1] TYNDP 2026 Scenario Building process, with focus on the central scenario.

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[1] *The TYNDP scenarios have been jointly developed by ENTSO-E and ENTSOG since 2018, with extensive stakeholders' consultation processes. The TYNDP scenarios in 2026 are developed following the ACER Framework Guidelines for the first time, and ENNOH is also an official contributor for the first time, pending it's final establishment expected in 2026.*

- Offshore Coherence: The methodology ensures alignment with ONDP infrastructure assumptions, integrating the 2025 updated Member States non-binding offshore targets, considering environmental protection & other uses of sea, and hybrid project developments.

- Stakeholder Engagement: The methodology development includes extensive coordination between TSOs, and consideration of previous stakeholders' feedback received through public consultations or Opinion.

Purpose and Audience

This document is intended to serve as a technical reference and implementation guide for conducting the IoSN process under the TYNDP 2026. It is targeted toward:

- Transmission System Operators (TSOs)

- Regulatory authorities

- Policy makers

- Project promoters and infrastructure developers

- Environmental stakeholders, academia and civil society,

Through a transparent and technically robust methodological framework, this document aims to ensure that all stakeholders can understand, contribute, and act on the outcomes of the Identification of System Needs process.

This methodology was developed in the context of the applicable legislation, Regulation (EU) 2022/869. There is a European Commission proposal to review this Regulation. For more information and to find ENTSO-E's position on the proposed reviewed regulation, visit https://www.entsoe.eu/european-grids-package/.

2. Objective of the TYNDP 2026 System Needs study

The primary objective of the IoSN study within the TYNDP 2026 cycle is to demonstrate pan-European cross-border electricity infrastructure development opportunities, including offshore corridor configurations that connect Members States' non-binding offshore Renewable Energy Sources (RES) with each other and with the onshore system. This methodology report documents the analytical framework applied to identify these opportunities. The study does not aim to prescribe specific investment decisions; rather, it seeks to highlight where and how system enhancements can most effectively and economically support Europe's energy transition and internal market objectives for 2035, 2040, and 2050.

2.1. Overall objectives

- Provide a coordinated and transparent assessment of cross-border transmission capacity needs and offshore corridor needs in the European electricity network across three target horizons.

- Inform stakeholders about potential system configurations and expansion possibilities that facilitate renewable integration, sector coupling, market integration and system security, for minimum system operational costs.

- Inform stakeholders about the potential impact of cross-border infrastructure developments and offshore network development on the internal national electricity networks. This also includes the information on additional internal operating costs.

2.2. Specific objectives

- **Identification of Strategic Opportunities**

    o **Onshore Transmission Capacity Needs**: Quantify additional onshore cross-border capacities required to meet scenario targets, reduce RES curtailment, and improve power flow efficiency, at least cost.

    o **Storage Capacity Needs**: Quantify additional storage capacity required in the longer-term horizon to ensure flexibility in a power system with high-RES penetration.

    o **Offshore Hybrid Corridors**: Characterise options for interconnections, and radial, or hybrid generation connection.

    o **Impact on the internal network:** Identifying the impact of the cross-border needs on the internal network, and the resulting change in the costs of the energy system.

- **Strategic System Goals**

- o **Renewable Energy Integration**: Evaluate how network enhancements support the integration of variable renewables (wind, solar, hydro), minimising congestion and curtailment in an adequate system.

- o **Energy Security and Resilience**: Evaluate how network enhancements help mitigating supply risks under high renewable penetration and changing climatic conditions, reinforcing system stability and black-start capabilities.

- o **Market Integration and Convergence**: Evaluate how network enhancements facilitate price convergence and efficient cross-border exchanges by alleviating network constraints, supporting the single European electricity market objective.

- o **System Sustainability**: Evaluate how network enhancements support Europe's commitment to reducing greenhouse gas emissions and transitioning to a low-carbon energy system.

- o **Flexibility and Operational Stability**: Assess the role of storage in complementing transmission developments to manage variability and maintain system security.

- **Structural Modelling Enhancements**

  - o **Zonal Model Development**: Build a zonal representation for all time horizons, going beyond the traditional one-node-per-country approach. This gives the possibility to better capture the physics of the electricity power flow, as well as internal network constraints and national bottlenecks. Detailed offshore node granularity - including hybrid corridor candidates - to more accurately reflect the long-term system topology of the offshore grid.

  - o **Robust Optimisation for multiple weather scenarios**: Develop a modelling approach ensuring that the outcome of the expansion optimisation properly accounts for the uncertainties of future weather scenarios. In particular in TYNDP 2026, three weather scenarios are considered for each target year assessed, each of them having a certain weight (or probability). By using this optimisation approach, the set of selected investment options for each of the target years assessed is optimal in covering its weather scenarios uncertainties.

- **Integrated Methodological Framework**

  - o **Unified Onshore/Offshore Assessment**: Apply a single modelling approach combining onshore grid with offshore corridor optimisation, ensuring consistency with Member States offshore non-binding RES targets.

  - o **Sector Coupling Inclusion**: Integration of hydrogen infrastructures (electrolysers, storage, pipelines) and hydrogen energy storage assets.

- **Deliverables and linked reports**

- o **TYNDP 2026 Infrastructure Gaps Report**: Presenting the results of the system needs identification study for the horizons assessed as well as the gaps in infrastructure planning.

- o **ONDP 2026 reports**: Presenting the results of the system needs identification study with focus on the offshore system, mapping offshore corridors potential with related costs and distances, for further integration of Member States non-binding offshore Renewables targets.

- o **IoSN Methodology Report**: Transparent and comprehensive documentation of assumptions, data inputs and modelling techniques for all target years, supporting transparency and stakeholder involvement.

3. Methodology

This chapter sets out the modelling decisions underpinning the assessment. It covers the formulation of the expansion optimisation problem, the technical, temporal and geographical scope, the definition of the starting grid, and specific considerations related to offshore transmission systems and hydrogen systems, as well as weather scenarios. The chapter then describes the zonal modelling approach, starting with the clustering methodology and concluding with an explanation of how market data are split into zonal market datasets. Finally, the chapter details the treatment of internal constraints and the investment modelling framework, and explains how environmental protection requirements and other uses of the sea are taken into account in the assessment.

3.1. Objective of an expansion optimisation problem

The core of the TYNDP 2026 IoSN study is formulated as an expansion optimisation problem of the pan-European electricity system: the aim is to determine where and how much new onshore transmission, offshore infrastructure, and storage capacity should be deployed to satisfy future scenarios most efficiently and economically. By casting the problem within a mathematical programming framework, the study identifies cross-border network capacities expansions, offshore corridor expansions, and energy storage deployments that minimize total system costs while satisfying technical, environmental, and policy constraints.

Detailed explanation of problem formulation is presented in Section 3.1.1, while Section 3.1.2 describes how it applies to the case of the TYNDP 2026 IoSN, in terms of input data, constraints, model granularity, etc.

3.1.1. Problem formulation

The expansion problem seeks to minimize the total system cost, accounting for future uncertainties in climatic conditions. The problem costs components comprise:

- **Investment Costs (CAPEX)** and **Fixed Operating and Maintenance Costs (FOM)** for investment candidates including onshore transmission lines, offshore cables and converters, and energy storage systems.

- **Operating Costs** (**OPEX**) of production assets over the modelling horizon.

- **Unserved Energy Penalties** to discourage load curtailment or supply shortages.

The optimisation performed for each target year can be expressed as follows in its standard mathematical form:

$$min_{x \in X}\{c^T x + \mathbb{E}_\omega[Q(x, \omega)]\}$$

Where:

- $c^T x$: The investment cost. The investment decision, represented by x, is assumed before the uncertainty ω is known. It is confirmed with the expected value of its impact which considered uncertainty.

- $\mathbb{E}_{\omega}$: The expectation operator over all weather scenarios ω in the uncertainty set Ω.

- $Q(x, \omega)$: represents the optimal operating cost for a specific scenario ω, with the hypothesis that you already committed to investment x.

The previous formulation can be expanded to take the following form[2]:

$$min \sum_{i \in I} C_i^{inv} x_i + \sum_{s \in S} \pi_s \left(\sum_{t \in T} \sum_{g \in G} C_g^{ope} P_{g,t,s} + VoLL \times ENS_{t,s} \right)$$

Subject to:

1. **Power Balance Constraints** at each node and time step t: generation + imports + storage discharge + curtailed demand = demand + exports + storage charge.

2. **Network Flow Constraints** reflecting power transfer limits and enforcing Kirchhoff's laws through DC load flow approximation.

3. **Capacity Bounds on Investment Options:** For each candidate element i, the amount of capacity built x_i is bounded between 0 and the maximum allowable build: $0 \leq x_i \leq X_i^{max}$. This is valid for linear expansions.

4. **Operational Limits**: generator, storage, and network must operate within technical limitations.

5. **Policy and Planning Constraints**: enforcing scenario-specific boundaries (e.g. renewable targets, offshore non-binding RES targets, energy efficiency targets, etc), taken from the TYNDP 2026 Scenarios.

Where:

- x_i denotes the amount of capacity built for each investment candidate i, and may include transmission or storage assets

- $p_{g,t,s}$ and $ENS_{t,s}$ denote respectively the dispatch level for production asset g, and the unserved energy at time t for scenario s.

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[2] *In this problem formulation, one can note that the investment decision in the optimiser (x_i) is set to be the same to all weather scenarios with their probabilities. This is called the **non-anticaptivity**. With this formulation, The optimiser must build the same capacity regardless of which scenario eventually happens. This yields to the most future-uncertainties-proof solution.*

- c_g is the variable operating costs of production assets in the system. $VoLL$ represents the Value of Lost Load, used to value unserved energy.

- π_s represents the probability of a scenario. In the TYNDP 2026, this corresponds to the weights of each of the weather scenarios considered for the target years assessed.

An expansion optimisation is performed separately for each of the studied planning horizons (i.e. 2035, 2040, 2050). This allows to navigate the future scenarios and see for each of the future target years assessed, the cross-border enhancements that would bring the most economical value at that target year.

The model adopts a two-steps Linear Programming (LP) the first step consists an expansion of real candidates only. Partially expanded candidates at this step are filtered out for reassessment in the subsequent step. In a second step, the investments options consist of all remaining real candidates, complemented with conceptual candidates and theoretical offshore candidates. The multi-steps optimisation is mainly suitable to manage the large model size and large number of investment candidates, as it helps in breaking down the problem. Following the two optimisation steps, a post expansion analysis is performed to filter out those borders for which the aggregated capacities are judged too little or unrealistic.

As mentioned earlier, a robust optimisation is performed to account for uncertainties on future climate conditions. For each target year assessed, three weather scenarios are considered within the optimisation problem, each of the weather scenario having its respective weight, seen as probabilities. The robust optimisation within the TYNDP IoSN is a first and represents one of the key innovations of this TYNDP 2026 IoSN.

3.1.2. Application in the TYNDP 2026 IoSN context

This section describes how and where the input data and the candidates are sourced for the TYNDP 2026 IoSN expansion modelling. It also outlines the granularity of the model, the expansion steps and aspects related to the post-processing of the results.

- **Source of Candidates**: The definition of investment candidates—whether onshore, offshore, or storage-related - is carried out in close coordination with TSOs and Regional Groups. This process combines bottom-up inputs (for instance based (or not) on concrete projects identified by TSOs) with top-down screening approaches (through theoretical potential, possibly constrained by predefined trajectories), ensuring that the expansion problem considers the broadest possible set of technically sound and relevant infrastructure options.

- **Scenario Consistency Across Tools**: The expansion model aligns with TYNDP scenario assumptions and inputs, ensuring consistency with PECD, PEMMDB, and national energy and climate targets.

- **Granularity and Zonal Definition**: Internal bottlenecks and regional constraints are captured via the zonal modelling approach (Chapter 3.8), enabling more accurate identification of system needs compared to single-node-per-country simplifications.

- **Dedicated Expansion Optimisation**: Separate expansion optimisation runs for each of the target years assessed (2035, 2040 and 2050).

- **Post-processing of expansions results**: model final outputs are filtered out to remove unrealistic capacities expanded (too small expansion).

3.2. Target years assessed

The TYNDP 2026 system needs assessment is performed for 2035-, 2040- and 2050-time horizons, for which the scenarios are in line with the TYNDP 2026 Scenario Building process, jointly managed by ENTSO-E and ENTSOG, with ENNOH in a supporting role.

The 2030-time horizon is not modelled for system needs assessment purpose given that it is too close in time with respect to the year 2026 of this TYNDP. Followingly, year 2040 becomes the most relevant year to study in the pan-European electricity system needs: year 2040 is in the middle between 2030 and 2050 where major European climate targets are set and is also a key year for European RES targets (especially for the offshore system). Additionally, 2040 is the horizon for which needs identified now can reasonably be translated into projects and realized.

The assessment of the three target years allows to have a short-term and long-term view on opportunities for the European electricity system cross-border developments, providing key insights for the downstream development of onshore and offshore network projects.

3.3. Model topology and geographical scope

The expansion problem definition from Section 3.1 is used to describe the European power and hydrogen system at a zonal level, i.e. multiple zones per bidding zone. The zones are the outcome of a clustering process (Section 3.8) based on the starting grid (Section 3.4). In this setup, each zone forms an individual market price, so that different market prices in one bidding zone are possible.

The model topology, shown in Figure 1, is divided into an electricity sector and a hydrogen sector. Each sector comprises generation and import units, flexible and inflexible demand units as well as storage units assigned to each individual zone, and transmission units that connect zones to one another. The electricity and the hydrogen sector are coupled through power-to-gas units such as electrolysis and hydrogen gas turbines.
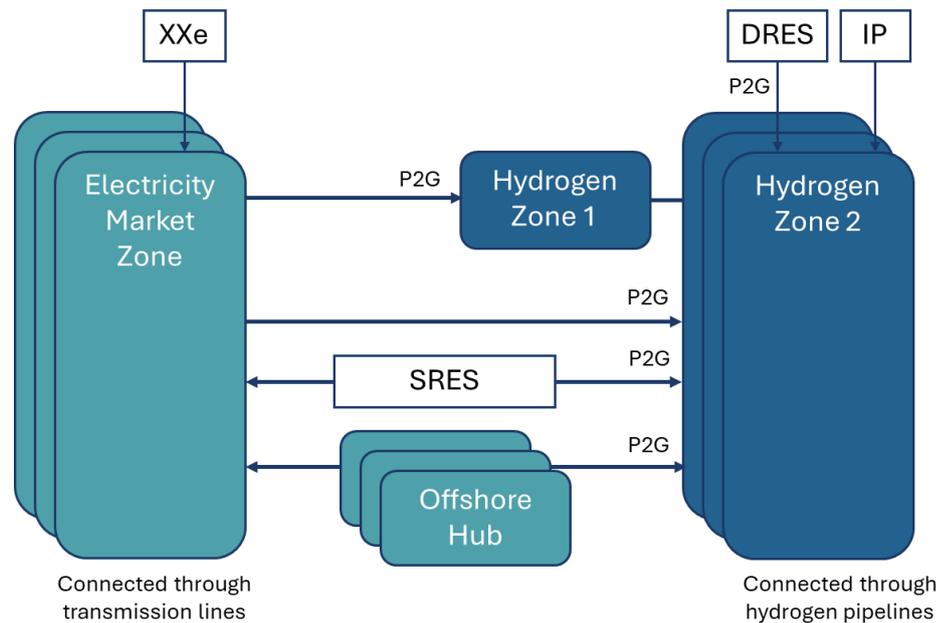
Figure 1. Model topology: Electricity market zones are connected through transmission lines, hydrogen zones 2 are connected through hydrogen pipelines. SRES: Shared Renewable Generation, DRES: Dedicated Renewable Generation.

3.4. Starting grid definition

In a transmission expansion planning, the starting grid represents the assumed level of development of the network at a given time horizon, which might need to be expanded to support the supply-demand evolution in a subsequent time horizon, or expanded for further optimisation of the existing system. As assumptions regarding the starting grid directly influence the outcome the of expansion exercise, it is important to define and document them clearly to ensure transparency and a proper understanding of the resulting expansion outcomes.

For the system needs assessment study performed in the TYNDP 2026 of ENTSO-E, the starting grid considered corresponds to a 2035 grid at cross-border level. The grid is built considering the existing grid of 2025 and its cross-border capacities, complemented by the following:

- TSO grid projects planned to be operational by 2035, potentially affecting cross-border capacities, including previous or current TYNDP projects to be commissioned by the delivery of the TYNDP 2026.

- All TYNDP 2026 projects that are considered to be part of the 2035 reference grid, with planned commissioning date in 2035 at latest, and satisfying criteria a, b and c of reference

grid definition as outlined in section 2.5.1 of the 4th ENTSO-E Cost Benefit Analysis Guideline of grid development projects[3]. The criteria are:

a) The project is in the 'under construction' phase

b) The project has successfully completed the environmental impact assessment

c) The project is in either the 'permitting' or the 'planned but not yet permitting' phase and its timely realisation is most likely. See further details on these criteria directly in the 4th CBA guideline.

The figure below shows the starting grid aggregated cross-border capacities and the list of TYNDP projects included in the starting grid are presented in Annex 6.2

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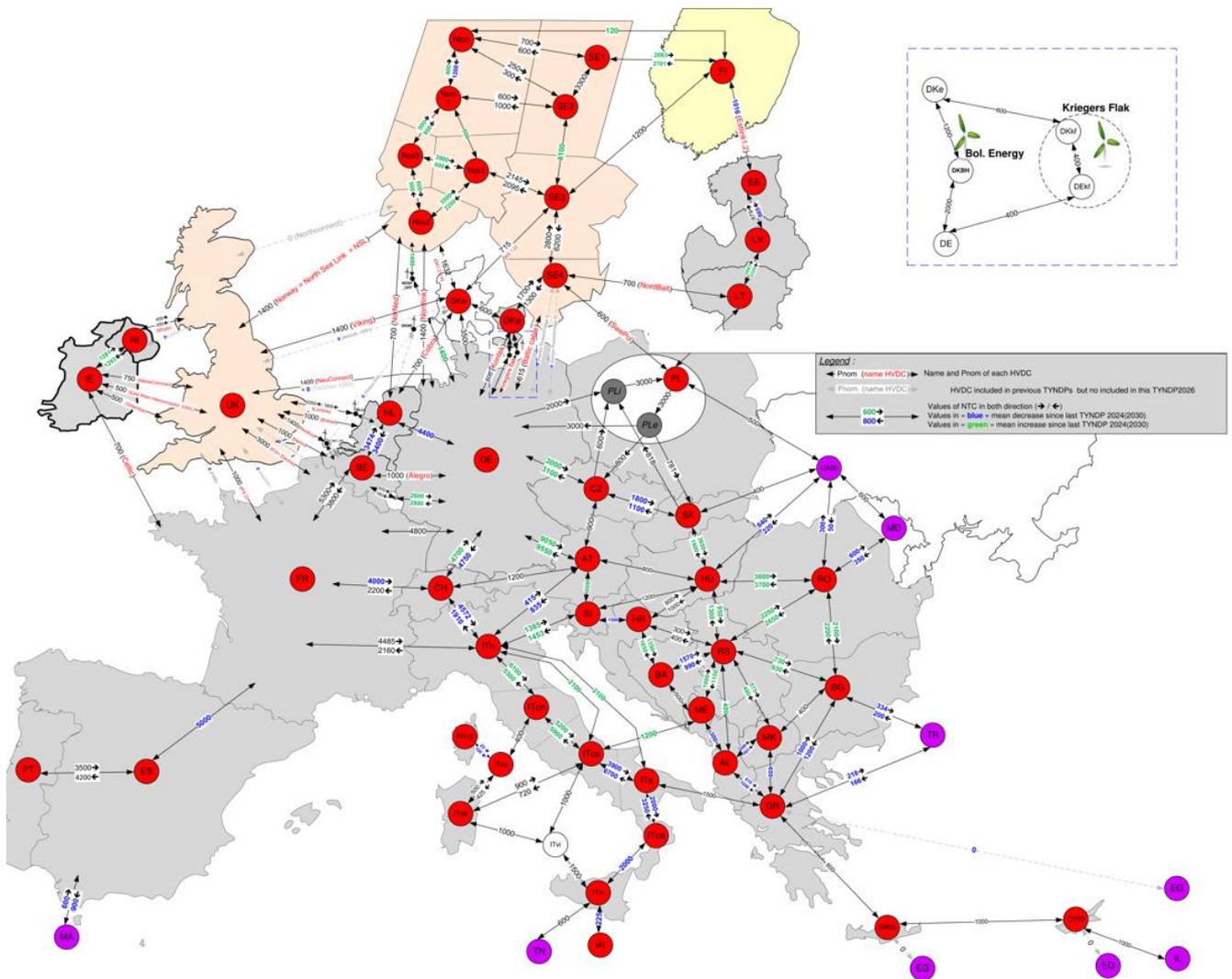
[3] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/news/2024/entso-e_4th_CBA_Guideline_240409.pdf

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Figure 2: Electricity starting grid of the TYNDP 2026 IoSN (NTC form) cross-border capacities

3.5. Offshore system assumptions

The offshore system starting grid and installed offshore generation capacities are defined through a top-down approach, in which the offshore non-binding Renewable Energy Sources (RES) targets, as defined by the Member States and submitted by the TSOs to the TYNDP, are treated as fixed inputs. The top-down exercise identifies offshore corridors that best support the integration of these RES targets into both electricity and hydrogen system. As part of the starting grid, existing and planned offshore hybrid projects are accounted in the starting grid of the offshore system, as already applied in the ONDP 2024. Similar criteria applied for the onshore TYNDP projects, as described above, is applicable for the offshore TYNDP projects, for building up the starting grid.

3.6. Consideration of the hydrogen system

When assessing the economic benefits of potential new cross-border electricity transmission capacities, the supply dispatch of the hydrogen system is optimised alongside the expansion and supply dispatch of the electricity system. Electricity transmission infrastructures expansion has various effects on the electricity system, as well as on the hydrogen system (for the case of the TYNDP coupled system). These effects all support overall system costs reduction and market integration. Electricity transmission infrastructure can enable more power-to-gas production for green hydrogen, improve the management of hydrogen storages, and even increase hydrogen exchanges between neighbouring countries. Results from the TYNDP 2024 IoSN indicate that 20% of the value of the electricity grid expansion for the 2040 time-horizon results from profits generated within the hydrogen system.

In TYNDP 2026, an explicit modelling of the hydrogen system is considered to ensure that a holistic view of the system is accounted for in the expansion planning of the electricity system. Information on the hydrogen system infrastructure, supply and storage potential, and demand are in line with the TYNDP 2026 Scenario Building process. The assumed level of development of the hydrogen system transmission infrastructures for the different target years is subject to public consultation together with the electricity transmission starting grid.

A sensitivity is performed on the hydrogen system modelling to appraise only the benefits due to optimisation of the electrical system. To do this, the dispatch of the hydrogen system can be frozen – in other words, taken as a given, static and not optimised. An expansion carried out on such a system will only optimise the electrical part of the system. The hydrogen system can be frozen by taking, from the output of the pre-expansion model, the hourly electrolysis load at each electrical node. The interlinkage between the electrical and hydrogen nodes can then be frozen using the data.

3.7. Weather scenarios

The IoSN study must consider the uncertainty in climate-sensitive variables. Weather-dependent variations directly influence electricity demand, renewable generation profiles, and hydroelectric

resources behaviour, all of which critically affect system operation, adequacy and flexibility requirements, and long-term investment outcomes.

To address these uncertainties, a stochastic weather scenario framework has been developed, ensuring that modelled system behaviour remains robust under a wide range of meteorological conditions. The approach adopted to derive the weather scenarios to be used is fully aligned with the TYNDP 2026 Scenario Building process and the CBA process. The analysis considers multiple target horizons—2030 (2025–2034), 2035 (2030–2039), 2040 (2035–2044), and 2050 (2045–2054), each evaluated using climate projections from three independent models (CMR5, MEHR, and ECE3) for a range of 10 years, as seen in the parenthesis above for each target year. For each target year, thirty weather scenario series are generated, capturing the combined effects of interannual variability and model uncertainty.[4]

The primary weather-dependent variables include in an hourly resolution:

- **Electricity demand variations**, driven by temperature data and economic factors
- **Wind power capacity factors**, both onshore and offshore, aggregated at PECD zone resolution
- **Solar photovoltaic capacity factors**, reflecting combined regional solar resource profiles
- **Hydro inflows**, comprising both reservoir and run-of-river components, represented at weekly resolution

In addition, **heating and cooling degree days** are derived from population-weighted temperature series to capture seasonal impacts on electricity demand patterns. The selection of representative weather scenarios follows a multi-step quantitative procedure designed to identify a small subset of climate-year combinations that are statistically representative of the broader dataset. The procedure consists of the following key stages:

1. **Calculation of yearly averages and cumulative anomalies:**
   For each variable, region, and climate-year, average values are computed across all relevant time steps (hourly, daily, or weekly). Cumulative anomalies are derived relative to multi-model mean values, providing a consistent basis for cross-scenario comparison.
2. **Computation of aggregate statistics and normalisation:**
   Overall averages and standard deviations are calculated across all years and models. These statistics are used to normalise each variable, ensuring comparability across scales and data sources.
3. **Application of regional weighting factors:**
   Weighting factors are determined according to regional installed capacities of renewable technologies. This ensures that regions with higher system impact exert proportionally greater influence on the weather scenario selection process.

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[4] *PECD 4.2 SSP 2.45 climate models: CMR5, ECE3, MEHR. For information on the PECD please see: https://cds.climate.copernicus.eu/datasets/sis-energypecd?tab=overview & https://confluence.ecmwf.int/pages/viewpage.action?pageId=439598955 the PECD 4.2 will be uploaded on the website soon.*

4. **Dimensionality reduction:**
   Principal Component Analysis (PCA) is employed to reduce the multidimensional dataset into a smaller set of uncorrelated components that capture the dominant patterns of variability across weather years.
5. **Scenario clustering (K-Means):**
   The normalized PCA results are grouped using K-Means clustering (k=3). Each cluster represents a distinct category of weather behaviour—typically corresponding to average, mild, and extreme climatic conditions. For each cluster, the climate-year closest to the cluster centroid is identified as the representative year.

The outcome of the process is the selection of **three representative weather years per target period**, each reflecting distinct but realistic climatic conditions. These representative series serve as inputs to subsequent system expansion optimisation, ensuring that investment options are stress-tested against a realistic spread of meteorological conditions.

Comprehensive details of the input datasets, calculation procedures, and statistical analyses applied are presented in Annex 6.3 **6.3Weather scenario selection methodology**. The annex includes full descriptions of variable definitions, mathematical formulations, and illustrative examples of the PCA and K-Means clustering results.

For the TYNDP 2026 cycle, the selected weather scenarios for the different time horizons studied are as follows (in between parenthesis are the weights):

- **2035:** WS032, WS037, WS059 (0,24; 0,43; 0,33)
- **2040:** WS065, WS071, WS077 (0,20; 0,40; 0,40)
- **2050:** WS091, WS092, WS106 (0,23; 0,57; 0,20)

Those represent the following combinations of the target years, climate models and emission scenarios:

Table 1 Weather Scenario Parametrisation

Code name	Time period type	SSP scenario	Climate model	Climate year	Study Target Year
The code name of the PECD weather scenario	The data time period type of the weather scenario data	Shared Socio-economic Pathway scenario	The PECD climate model used for generating this weather scenario	The calendar year represented by this weather scenario	The TYNDP study requirement of the weather scenario
WS032	Projection	SSP245	CMR5	2031	2035
WS037	Projection	SSP245	CMR5	2036	2035
WS059	Projection	SSP245	MEHR	2038	2035
WS065	Projection	SSP245	CMR5	2039	2040
WS071	Projection	SSP245	ECE3	2035	2040
WS077	Projection	SSP245	ECE3	2041	2040
WS091	Projection	SSP245	CMR5	2045	2050
WS092	Projection	SSP245	CMR5	2046	2050

| WS106 | Projection | SSP245 | ECE3 | 2050 | 2050 |

3.8. Zonal clustering

In previous TYNDP cycles, an NTC model as well as a zonal model were used. The zonal clustering (and network reduction) methodology has been significantly improved during TYNDP 2022, and the approach has also been used for TYNDP 2024.

The NTC represents the maximum exchange that can take place between two neighbouring bidding zones, in a certain direction. Thus, the NTC model contains a set of zones (usually one zone per country, following the existing bidding zone configuration), connected by NTC values. Nevertheless, the market exchange flow and the resulting physical flow on a border may not be equal, due to loop or transit flows, which occur in meshed grids. Interdependencies between borders cannot be fully captured with the NTC model (as the zones are represented by copper plates with connections modelled equivalent to HVDC links).

The zonal model, as opposed to the traditional NTC model, can better reflect physical flows, as it allows to integrate a simplified model of the physical grid directly into the market model. By using a clustering methodology, the initial zones (from the NTC model) are split into multiple ones. Based on the resulting zones definitions (N per country), a network reduction is performed to derive the parameters of the connecting links, each characterised by a maximum capacity and an impedance. Thus, in the zonal model, the zones are represented by copper plates with connections equivalent AC links.

Some distinctive features of the zonal and NTC approaches are shown below in Table 2.

Table 2: Differences between the zonal and NTC approaches

Approach	Nodes / zones	Links	Binding constraints	Results	Robustness of generation and load assumptions	Accuracy in flow assessment
NTC model	(usually) 1 per country	Cross-border	None	Copper plates with connections equivalent to HVDCs	+	-

Zonal model	N per country	Cross-border & internal	Kirchhoff's mesh rule	Copper plates with connections equivalent to AC links (closer to flow-based functioning)	-	+

The differences between the approaches are further illustrated in Figure 8, where a simple example is provided. The example consists of 4 nodes (or zones) and 5 links, each with a maximum capacity of 1 GW. The figure also depicts the different load and generation types and values connected to each node.

A dispatch using the NTC model (on the left) leads to each link being loaded to 1 GW, which respects their maximum capacity. However, the same dispatch with a zonal model (on the right) results in different flows driven by the links' impedances (for simplicity, all impedances in this example are considered equal $X_{AB} = X_{AC} = X_{AD} = X_{BD} = X_{CD}$). This causes link AD to be overloaded, while the other links still have remaining capacity. Therefore, the dispatch optimum from the NTC model is infeasible and a different solution needs to be found.
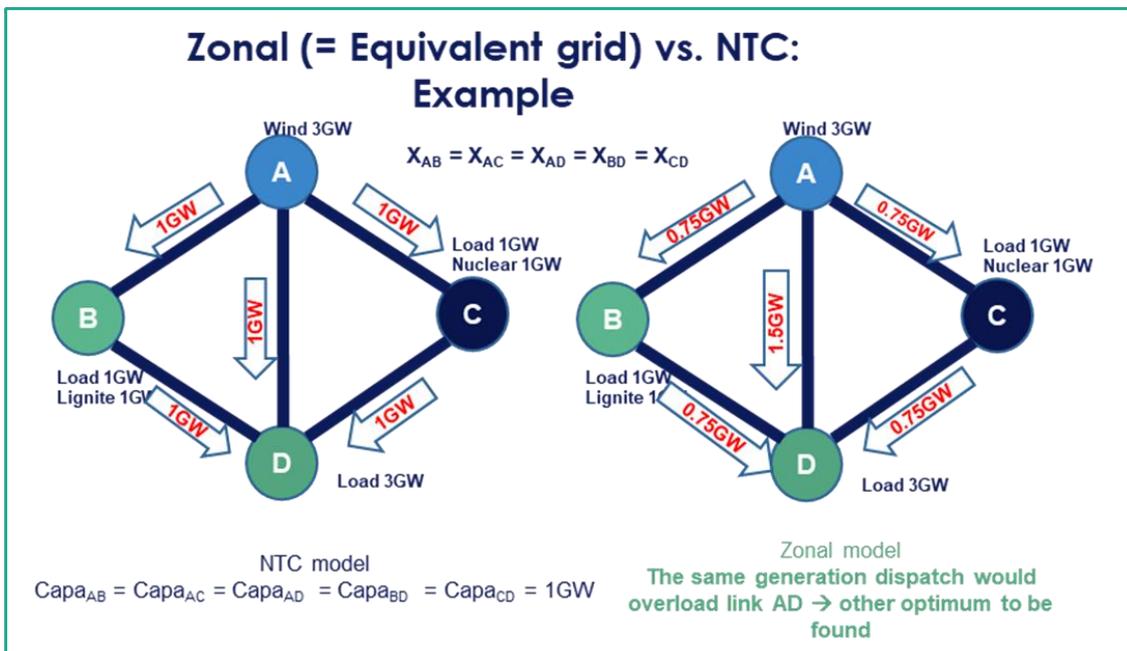

Figure 3: Differences between the zonal and NTC approaches for a simplified example

The zonal modelling process is shown in Figure 4. The steps for the network reduction and zonal clustering processes are briefly described in the subsections below, and more details are provided in Annex 6.1
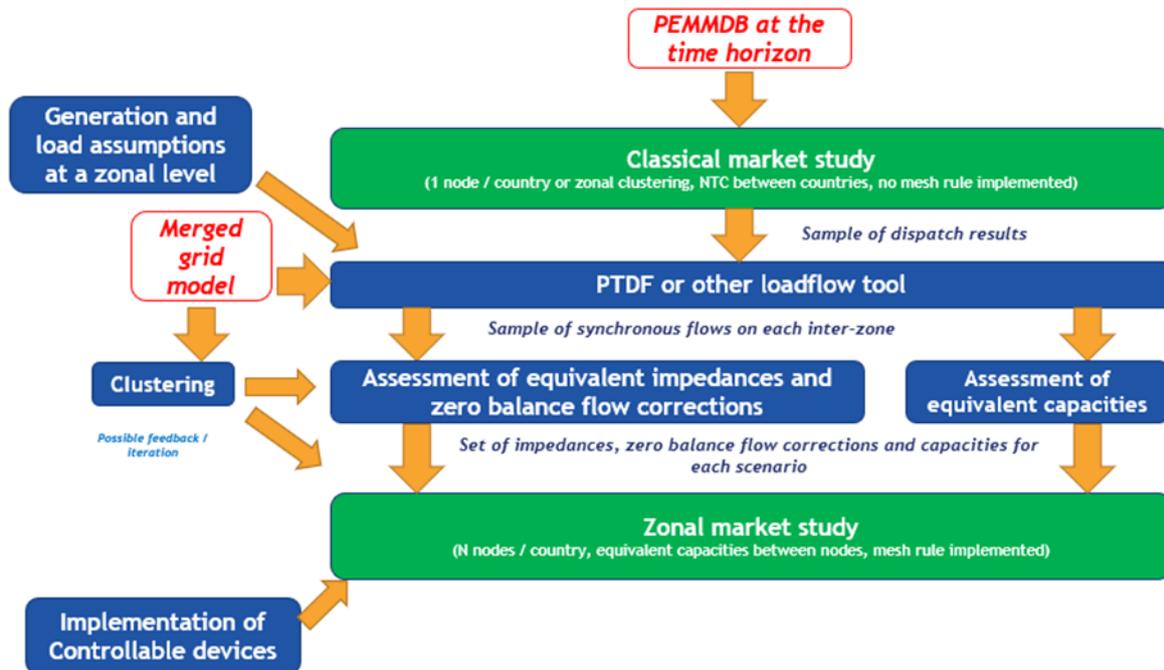
Figure 4: Overview of the zonal modelling process

3.8.1. Zonal clustering definition

The clustering process consists of a network reduction that generates a simplified representation of the pan-European transmission network, from thousands of nodes into a smaller set of clusters or zones (within the range of 100), which are linked by inter-zone connections. The clustering primarily represents a compromise between three criteria, shown in Figure 5:

1. **Include the constrained lines in the equivalent inter-zone**

    The first criteria ensures that critical lines (whether constrained or sensitive to cross-border exchanges) remain as inter-zone connections and can be monitored in the model, and that the dispatch can be adapted by avoiding any overload on those inter-zone connections.

2. **Ensure a good quality of the equivalent network**

    The second criterion is related to the choice of lines to be aggregated by the same inter-zone connection. To ensure a good quality, the best approach is to group together inter-zone links with similar behaviour. For instance, if some lines have flows in opposite directions, the equivalent flow of the inter-zone connection would be close to zero because it would be the sum of all the flow of the links. This would lead to the equivalent capacity calculated being also close to 0 MW, which is not realistic. In addition, the optimizer (see section 3.8.2) would

not be able to find a single value for the equivalent impedance which would reflect objectively the behaviour of the equivalent link.

3. Reduce the number of resulting clusters

The third criterion aims to reduce the number of resulting clusters to ensure feasible computation time. Implementing the first two criteria would in principle lead to a massive increase of the number of zones. While increasing the number of zones would lead to more accuracy of the reduced network, it would have a negative impact on the computation time, and it may also negatively affect the robustness of the zonal hypothesis, regarding the granularity of the generation and load assumptions. In fact, the higher the number of clusters, the higher the uncertainties are on the inferred hypotheses, which could lead to an illusion of precision.

1 – Equivalent link composed of constrained lines

- Aligned with long-term monitoring
- Lines which are sensitive to exchanges may also be included

2 – Good quality of the equivalent network

- Calculation of flows and capacity of equivalent links
- A good practice is to put "synchronous" lines (flow in the same direction) on the same equivalent link

3 – Number of zones

- The 2 previous criteria could be met by massively increasing the number of zones, but at the cost of computation time and robustness of results

Figure 5: Criteria considered for clustering

Besides the three main criteria presented above, a decent clustering process need to consider other aspects as well. For example, inside a zone, the grid must be connected (a good grid reduction cannot be ensured if there are two or more isolated parts inside the same zone). Another aspect is ensuring that the sizes of the zones are as proportional as possible (a large zone connected to much smaller ones would massively affect their behaviour, thus also the overall clustering quality). Finally, the consistency of the zones with PECD ones could ease the process of splitting the country hypothesis into zonal ones.

Reliable number of clusters has been tested and established a few cycles ago, taking into account the quality of the reduction performed, the strategic lines being monitored, and the computation time. A compromise number found is 102 as shown in Table 3 (total sum). A combination of all criteria mentioned above is used to determine that number.

The topology of the zonal model used in the study is shown below in Figure 6, in the form of resulting clusters. An overview of the number of zones per country is given in Table 3.
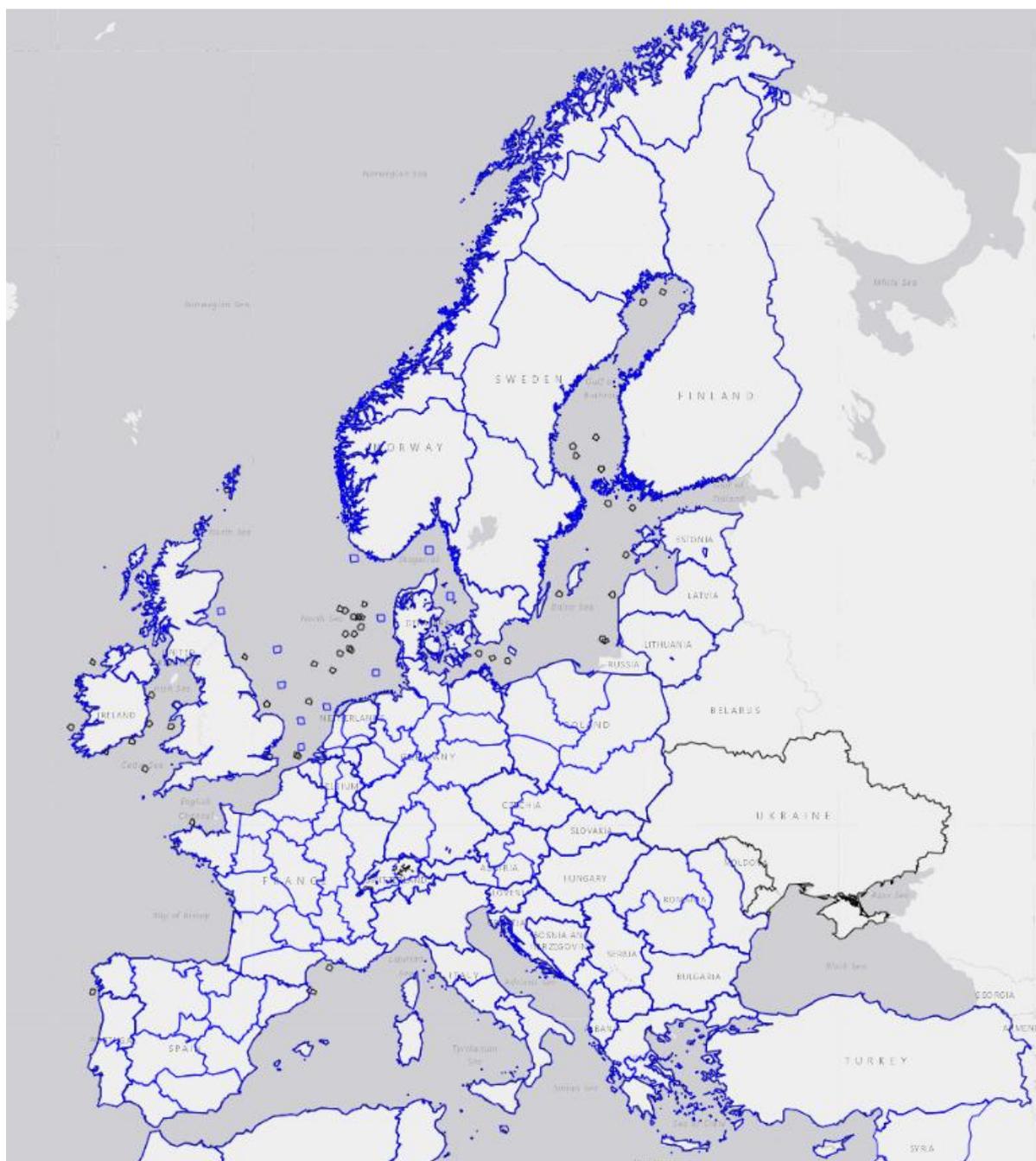
Figure 6: Zonal model topology used in the study (North African and Middle East countries are kept to one node per country).

Table 3: Overview of the number of zones per country used in the study

Country	Number of zones
Albania	1
Austria	4
Belgium	3
Bosnia	1
Bulgaria	1
Croatia	1
Cyprus	1
Czech Republic	2
Denmark	2
Estonia	1
Finland	1
France	16
Germany	11
Greece	2
Hungary	1
Ireland	1
Italy	7
Latvia	1
Lithuania	1
Luxembourg	1
Macedonia	1
Malta	1
Montenegro	1
Netherlands	5
Northern Ireland	1
Norway	3
Poland	5
Portugal	2
Romania	3
Serbia	1
Slovakia	1
Slovenia	1
Spain	10
Sweden	4

Switzerland	2
Turkey	1
United Kingdom	1
Total	**102**

3.8.2. Network reduction

Starting from the initial set of zones (from the NTC model) and the full initial network, the clustering process can be applied, resulting in a new set of clusters (in which several nodes are aggregated). Equivalent links ("inter-zone connections") are defined between clusters, and a network reduction is performed to derive the respective parameters, namely the equivalent capacities and impedances. This is exemplified in Figure 7. With this approach, no intra-zonal congestion occurs.

Figure 7: Example of network reduction from a detailed to a zonal network

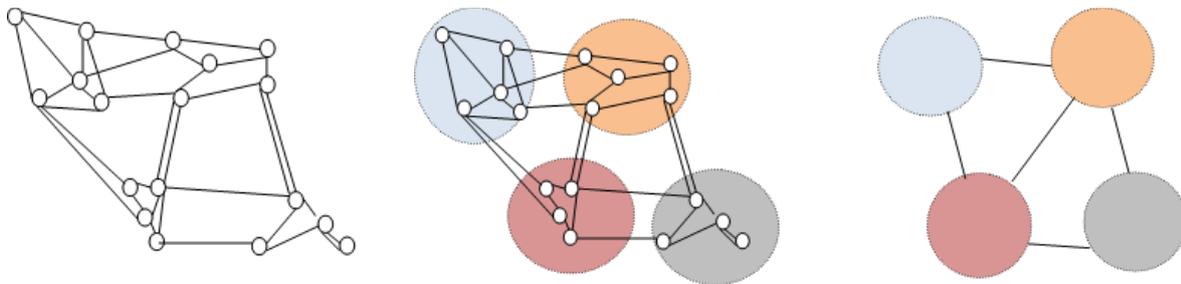The simplified AC network thus obtained is an equivalent electrical network, and each inter-zone connection will have an equivalent impedance and capacity defined. Note that both the equivalent impedance and equivalent capacity of an inter-zone connection are results from optimization problems, and not necessarily the sum of the impedances or capacities of its individual links, although in some cases the values could be similar.

For determining the equivalent impedances of the inter-zone connections, an optimisation problem is solved which determines the optimal set of impedances and flow corrections minimizing the error between estimated flows (with the simplified grid) and target flows (with the detailed grid) on all equivalent links. The equivalent impedances are required to implement Kirchhoff's second law (mesh law) in the zonal market model - note that Kirchhoff's first law is already respected.

The equivalent capacity of an inter-zone connection represents the maximum flow on the highest loaded line of this inter-zone connection which is still N-1 secure (this means that a flow above this value, combined with an outage, would overload that link). This takes into account the effects of loop and transit flows and also uses the Line Outage Distribution Factors (LODF) matrix when determining the N-1 equivalent transfer capacities. Moreover, they can also be determined separately for each direction (transfer capacity X -> Y and Y -> X) or for summer and winter values.

3.8.3. Output of the network reduction

The output of the electrical network reduction model contains providing specific results derived from the reduction process, as described below:

1. **No-Load Flows**
   The no-load (zero exchanges between zones) power flows across each inter-zone connection of the reduced network.
2. **Reduced Network Loop FLows**
    The loop (mesh) equations of the reduced network, defining the algebraic relationships between inter-zonal flows and the network topology after reduction.
3. **Impact of HVDC Systems on No-Load Flows**
   The impact of the various HVDC systems on the no-load flow distribution within the reduced network.
4. **Reduced Link Capacities**
   For each inter-zone connection, four capacity values are provided: summer and winter capacities, in both direct and indirect directions. All capacity values are computed considering the N-1 security criterion.
5. **Reduced Link Impedances**
    The equivalent electrical impedances of each reduced inter-zone connection, as determined by the reduction model.
6. **Impact of Phase-Shifting Transformers (PSTs)**
    The influence of the PSTs on the network, by providing the phase-shifting power capability of each PST (expressed in megawatts), indicating the range of active power adjustments enabled by the transformers.

3.8.4. Market data split in zonal datasets

For market simulations, market datasets are typically aggregated at bidding zone level, encompassing variables such as electricity production, demand, and other market or electrical indicators. While this aggregation provides a high-level overview for socio-economic analysis, the objective is to disaggregate these data towards zonal granularity for the IoSN study, enabling a more spatially resolved representation of the energy system across different regions within each bidding zone which is consistent to the reduced network model.

Market data disaggregation at zonal level is primarily guided by the electrical network clustering. Based on the existing grid model, nodes are assigned to their corresponding clustered zones while the PEMMDB database provides information on the assets –generation units, storage units, etc. – connected to each node. This information enables the derivation of allocation keys for each variable of interest, allowing national-level data to be redistributed to the appropriate zones. Regarding the demand, splitting factors for the different subzones are defined for variable loads by TSOs, and industrial load are also reported with their connection points.

The process requires several variable-specific considerations. For demand, it is necessary to distinguish between fixed and flexible loads, ensuring that the spatial allocation reflects their respective characteristics. For renewable generation, there are typically two distinct input datasets to consider: one derived from the detailed grid model (substation to which the asset connects) and another from the PECD database (PECD zone where the asset is located – relevant for its generation profile), an alternative data source. These datasets are reconciled to ensure consistency between the capacities allocated to the different IoSN zones, as well as the capacity factors for each of these capacities.

For thermal generation units, additional attention is needed to maintain coherence between the detailed network representation and the zonal model. This involves maintaining both the number of thermal elements and their equivalent installed capacities during the disaggregation process.

3.9. Consideration of internal constraints

In TYNDP 2026, the zonal model allows to consider internal constraints within a bidding zone. The IoSN optimisation process is conducted in Load Flow (LF) mode – where only cross-border capacities are activated – to determine the economically optimal interconnection portfolio. The zonal model in LF represents the physics of the network (mesh law etc.), but interzone capacities are set to infinity. This means that if congestion on interzones is already present in the initial model, it will not influence the development of new interconnections. Thus, the IoSN portfolio will not be limited by internal constraints, nor will mitigate already existing internal congestions by cross-border expansion.

Then, to assess the impact of internal constraints we will run dispatch simulations with and without the IoSN portfolio. This would give us the additional volume (or cost) of change of dispatch caused by the IoSN portfolio. This will indicate what reinforcements might be needed to go hand in hand with the development of interconnections, hence where they could be implemented.

Additional studies can be performed to determine whether the interconnections identified in the optimisation remains cost-effective and economically viable with internal constraints activated. This can be done by running the expansion optimisation in Optimal Power Flow (OPF) mode — which also takes into account the internal capacities — to foster in the limitations of the internal networks in the resulting optimum portfolio of the expansion planning. In the way this OPF expansion is set up, it allows to show what would be the outcomes of the cross-border expansion without further increasing internal network congestion.

However, a mismatch between the generation mix and the network used may already lead to significant constraints in the reference network (before the expansion optimisation loop). The optimizer may then invest in interconnections to bypass congestion points. This must be avoided as the goal of this additional study is to confirm the cost effectiveness of the LF expansion interconnection portfolio under a constrained internal network. To ensure this consistency, the candidates' portfolio of this variant will be capped by the results of the LF expansion.

3.10. Investment modelling framework

In the IoSN study, the optimization approach applied consists of assessing each of the studied target years separately. The starting grid at the borders corresponds to the year of 2035 as specified earlier, and this is the starting point of the expansion optimisation performed for 2035, 2040 and 2050. The expansion for 2040 and 2050 would help deriving the cross-border enhancements that help meeting the scenarios developments from 2035 towards 2040 and 2050 respectively. The expansion optimisation performed for 2035 would help identifying cross-border transmission system enhancements that would support a more efficient operation of the 2035 scenario system.

A multi-steps expansion is performed for the target years assessed as described below:

- First, all real expansion transmission candidates (both onshore and offshore) from the transmission investments list are fed to the model and the optimiser selects the optimum combination of investment candidates that minimises total system costs. This expansion step follows a linear programming optimisation, where these real candidates are either built fully, partially or not at all.

- In a second step, all remaining real candidates, conceptual onshore candidates and offshore theoretical corridors candidates are fed to the model, while properly accounting for the selected investments candidates from the first step. This expansion step is calculated by a linear programming optimisation as well. This is particularly useful for the top-down approach where maximum grid enhancement potentials are set (through the candidates defined) and the model can freely define the optimum combination of deployment, without exceeding the potential set.

- Storages are then expanded (only for the 2040- and 2050-time horizons[5]) also following a linear expansion approach, where maximum trajectories cap the maximum expandable capacities for the various countries. Storages of different storage sizes are explored, to mimic different flexibility types provided by the different types of storages. Very small or unrealistic expansion values should be naturally filtered out.

3.11. Environmental protection and other uses of the sea

In the development of the offshore transmission grids, many factors related to the bathymetry of seas, but also environmental protection and other uses of seas drive the location, sizing and routing of offshore infrastructures. While the bathymetry of a seabed is known and rather unchanging, the other constraints are generally subject to more changes and driven by national and international policies/plans. The Maritime Spatial Plans (MSP) reports generally reflect these environmental constraints and other uses of seas.

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[5] For the 2035 horizons, the level of storages deployment corresponds to the levels defined in the TYNDP 2026 scenarios, which are meant to follow NECPs

These MSP contain information related to the plans for the different uses of seas within and across the different administrative borders. These plans can include areas dedicated to (non-exhaustive list): aquaculture, phishing, maritime transport, military training, raw material extraction, scientific research, infrastructures (cables, pipelines, platforms, artificial islands, bridges, etc.), tourism and recreation. The plans also include protected areas such as underwater cultural heritage. Each of these areas has a specific sensitivity, which will guide the choice of making an electricity infrastructure pass-by or through.

However, the availability and level of detail of MSP is not the same for all member state in all the priority offshore grid corridors (sea basins) of interest for the integrated ONDP. Additionally, most MSPs do not extend to horizons that are of interest for the ONDP, meaning the 2040- and 2050-time horizons. Therefore, using these MSPs for defining optimum rerouting of offshore transmission corridors investment candidates, allocating penalty costs of going through different areas of the sea might provide an illusion of accuracy, for an increase complexity in offshore investment candidates definition and a possibility of unfairness between the different sea basins due to different level of data availability.

Nevertheless, the outcomes of such assessment are an updated length and CAPEX cost for each offshore investment candidate are valuable information, reflecting the extra length and cost needed to move from straight line connections to rerouted realistic connections. A simpler approach consisting of a factor of increase is uniformly used across all sea basins for theoretical offshore candidates. This increase factor is in the range of 10% to 15%, derived from studies of maritime spatial planning. The exact factor used will be specified in the final version of this document. The definition of offshore nodes used for the modelling on the offshore system is realised by the TSOs, which ensures a consideration of other uses of sea in the definition of those nodes.

4. Input data

The quality and transparency of the expansion analysis in the TYNDP 2026 IoSN study rely fundamentally on the robustness of the market and network input data. Each category supports a different facet of system modelling, such as energy demand, installed generation capacities, economic assumptions, grid representation, and infrastructure constraint modelling. These inputs are scenario-specific and aligned with the TYNDP 2026 Scenario Building process.

Market Data

The market data describe the demand-supply landscape and economic parameters under each scenario and are drawn mainly from National Energy and Climate Plan and associated datasets. Key elements include:

- **Demand profiles**: Time series of hourly electricity consumption, including electrification effects (e.g., heating, EVs, industrial transformation).

- **Generation capacities**: Installed and available capacities per technology (onshore and offshore wind, solar, hydro, thermal, nuclear), reflecting scenario assumptions derived from national plans.

- **RES profiles and weather scenarios**: Hourly capacity factors time series derived from climate models which introduce a varied perspective on future climatic conditions, enhancing the robustness and reliability of the analysis with a forward-looking perspective.

- **Hydro inflows and hydro management constraints**: National and regional inflow profiles and reservoir operation constraints.

- **Flexibility assets**: Technical parameters for energy storage systems (e.g., batteries, pumped hydro), demand-side flexibility, and hydrogen electrolysers.

- **Economic parameters**: Technology-specific fixed and variable costs (OPEX), CO_2 prices, Value of Lost Load. CAPEX information is considered for investment candidates.

Data are provided for each of the three target years (2035, 2040, 2050) and consistently mapped to the spatial and temporal resolution of the expansion model.

Network Data

Network data provide the electrical topology and technical parameters necessary for evaluating transfer capabilities, congestion patterns, and potential reinforcement needs.

- **Grid topology**: Based on the pan-European merged common grid model, including assets such as cross-border and internal transmission lines, substations, converters and transformers.

- **Initial capacities and operational constraints**: Thermal limits, flow directions, and operational flexibility of existing lines and converters.

- **Zonal clustering**: Definition of zones and subzones derived from the network reduction process. Each zone aggregates several nodes while preserving key structural bottlenecks.

- **Investment candidates**: Concrete projects and conceptual transmission level infrastructure elements considered for testing in the expansion model. These include onshore cross-border reinforcements, offshore transmission corridors (interconnections, and radial or hybrid generation connection configurations), and storage assets..

A structured input set ensures that the system needs assessment captures the full interaction between market dynamics and physical infrastructure limitations, forming a reliable basis for identifying pan-European electricity system expansion or reinforcement opportunities. The following subsections briefly present the key input dataset used in the TYNDP IoSN study, focusing on two main aspects: the data included and its application in the process.[6]

4.1. Pan-European Market Modelling Database

The Pan-European Market Modelling Database (PEMMDB) is the central dataset providing all market-relevant information on generation, storage, and flexibility resources across Europe. It forms the backbone of the TYNDP models by describing the characteristics of each technology and the conditions under which they must operate in the electricity market.

The PEMMDB compiles data provided by TSOs, including:

- **Thermal generation**: Unit-by-unit and aggregated data for coal, gas, nuclear, oil, lignite, etc. (capacity, heat rates, forced outage rates, must-run levels).

- **Renewable generation**: Aggregated capacity for wind, solar, run-of-river, and other RES (linked to PECD profiles), provided at PECD and bidding zones levels.

- **Storage**: Data on batteries, pumped hydro, and reservoir capacities (MW, MWh, efficiency).

- **Demand-side response (DSR)**: Aggregated flexible demand potential.

- **Power-to-X (P2X)**: Electrolyser and power to heat aggregated capacities with efficiencies and other technical constraints.

- **Fixed exchanges**: Required fixed exchanges between some ENTSO-E countries and specific zones.

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[6] *The full breadth of the market data is made available on the TYNDP scenarios landing page at the time of the draft scenarios publication: https://2026.entsos-tyndp-scenarios.eu/. However, the starting grid, investments candidates and economic parameters are made available in the annexes of this methodology report, as they are specific to the system needs assessment.*

- **Costs and technical parameters**: Fuel costs, CO_2 prices, start-up costs, VO&M costs, derating factors, and maintenance schedule.

- **Balancing reserves**: Capacity withheld for reserves requirements (e.g. frequency containment or frequency restoration).

The PEMMDB feeds into the IoSN expansion model. Additionally, the PEMMDB feeds into the subsequent unit commitment and economic dispatch simulation, which simulates how resources are scheduled to meet demand cost-effectively under technical and market constraints, allowing to evaluate the impact of expansions plans outcomes.

4.2. Pan-European Climate Database

The Pan-European Climate Database (PECD) provides weather-based input data for electricity system modelling. It underpins renewable generation and is key for the preparation of dataset of demand timeseries and hydropower inflows and generation, with high-resolution (spatial and temporal) weather scenarios.

The PECD v4.2 considered in the TYNDP 2026 process is composed of both data based on historical observations and projected data for the future. These two datasets are also called historical stream (HIST) and projected stream (PROJ)[7]:

- **Historical (HIST)**: 42 weather years (1980–2021) based on ERA5 reanalysis data.

- **Projected (PROJ)**: 153 scenarios (2015–2065) from three CMIP6 climate models under SSP2-4.5.

Within TYNDP 2026, only a subset of PECD full dataset is used for the IoSN study. The selection of representative weather scenarios for the IoSN study is presented in section 3.7 and Annex 6.3.6.3

The PECD is used in the TYNDP 2026 to define the following data:

- **Wind and solar profiles** (hourly generation potential).

- **Temperature-dependent demand** (heating and cooling).

- **Hydro inflows** (river and reservoir series).

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[7] *Further details on the PECD 4.x preparation can be found in section 12.3 of the ERAA 2024 Annex 2 – Methodology report* *https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/ERAA/ERAA_2024_Annex_2_Methodology_v2.pdf*

The PECD is a foundation to key inputs of the IoSN modelling framework: it ensures that expansion options are tested accounting for weather variability and climate change impacts before defining the optimal set of options.

4.3. Hydropower database

The Hydropower database captures the availability and flexibility of hydropower plants. It includes inflows, reservoir storage levels, and operational constraints that govern hydro generation dispatch.

The hydro data are aggregated by study zone and technology type, with five categories:

1. **Run-of-river** – generation follows inflows, non-dispatchable.

2. **Pondage** – small reservoirs with daily flexibility.

3. **Traditional reservoir** – seasonal storage plants.

4. **Open-loop pumped storage plant** – pumped storage linked to natural inflows.

5. **Closed-loop pumped storage plant** – pumped storage without natural inflows.

Key parameters include:

- Natural inflows (daily and weekly)
- Reservoir levels (technical and historical constraints)
- Maximum and minimum power generation
- Pumping capabilities (where relevant).

4.4. Demand Forecasting Toolbox

The Demand Forecasting Toolbox (DFT) is ENTSO-E's tool to produce hourly load profiles for each study zone in Europe. It accounts for both structural demand (baseline consumption trends) and climate sensitivity (e.g., heating and cooling needs).

The DFT generates hourly time series of electricity demand, including those of electric vehicles and hybrid heat pumps. Additionally, the demand datasets are complemented with implicit and explicit Demand Side Response datasets (DSRs). Implicit DSR characterises those assets that are out of the market, but which are still sensitive to market prices; this includes a share of EVs, HPs and household batteries.[8] Explicit DSRs represent industrial DSR and are therefore directly in the market, with

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[8] *The data used in the TYNDP process are similar to those used in the ERAA process. Further details on the methodological approach used to define those iDSR can be found in section 2.3 of the ERAA 2025 Annex 2 – Methodology report*

predefined offered capacity and prices, with number of hours they can be used in a day. The latter comes within the PEMMDB as previously mentioned.

Demand profiles projections are integrated into the IoSN simulations. Electricity demand is dynamic, driven by weather, electrification trends, and consumer behaviour. To capture these dynamics a key driver to the optimum portfolio of system needs which should ensure minimum system costs to meet demand.

4.5. Investments candidates for the IoSN process

Investment candidates' data used in the system needs assessment process represent the options for provided to the optimiser for further expansion in the electricity grid, and for flexibility enhancements. The selected investment options will support ensuring the reliability, efficiency, and sustainability of the European electricity system. By feeding them to the expansion optimisation model, the most cost-optimum portfolio of system needs can be derived.

Here are the key components of investment candidates' data in the IoSN process:

- **Information on infrastructure projects**:

  o **Transmission grid development candidates:** Concrete and planned or conceptual transmission projects, onshore or offshore, with clear landing points and capacities of these projects. Some candidates are derived from TYNDP 2026 projects portfolio and complemented by further conceptual proposals from TSOs. The offshore candidates are complemented by theoretical candidates derived from a top-down approach. Details on the methodological approach are presented later in this section.

  o **Storages candidates**: Standard unitary capacities and rated power defined by ENTSO-E. Maximum expansion constraints (trajectories) defined by TSO to avoid unrealistic level of expansion that the model might find optimal.

- **Investment costs***:* Detailed cost estimates for infrastructure projects, including capital expenditures (CAPEX) – which may include internal reinforcement costs on top, operational expenditures (OPEX).[9]

  These costs are critical to the expansion planning problem formulation and drive the candidates' selection. During the investments candidates collection process, TSOs are asked

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https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/ERAA/ERAA_2025_Annex2_Methodology_ENTSOEProposal_Dec2025.pdf

[9] *As an alternative or supplement to internal grid expansion, OPEX could be increased by the additional redispatch costs required per year to show the costs of the missing internal grid development for the provision of additional trading capacities between the bidding zones. The results and findings of the PLI 'Redispatch' (basic results with the a existing "real" cross border expansion instead of the delta results) from the previous TYNDP cycle could potentially be used as a basis for this. This is not applied in the TYNDP 2026 IoSN but could be an item for reflection, in future developments.*

to review and/or confirm these costs, with a special care to the costs for the necessary internal grids reinforcement for each candidate.

During the investment candidates' collection, candidates are either collected as real or conceptual projects. Real candidates are made of projects submitted and to be assessed in the TYNDP 2026 CBA – as such they can either be projects from TSOs or projects from third party project promoters. On the other hand, conceptual candidates may be proposed by TSOs to be tested in the IoSN study to explore if they are associated to a system need. Below is a detailed description of the information required during the transmission candidates collection phase.

It should be noted that all transmission investment candidates (either they are DC or AC by nature) are modelled as DC links (representing market exchange potential) in the zonal model, with maximum capacity being their NTC impact. This is a limitation of the expansion modelling proposed in this document but can be justified by the difficulty to accurately model a link that connects two (or more) substations in a model made of clusters of substations.

4.5.1. Storage candidates' definition

In order to have the same storage opportunities for every country in the model, standard capacities, power and costs are centrally defined by ENSTO-E. At least two types of storage candidates will be defined in order to test both short- and medium-term storage (e.g. 4h vs 8h storages). The costs of most storages' assets are mainly driven by storage capacity, rated power and technology type. Given the complexity to model certain storage assets in an expansion model, the default technology type used in the IoSN expansion optimisation is battery, whilst the assumptions are not meant to reflect only batteries assets, and therefore the outcomes should not be translated as batteries needs but rather storage needs. This allows flexibility in the modelling, harmonised assumptions and comparability across all modelled market nodes.

The storage assets costs assumptions definition is inspired from the TYNDP 2024 Scenario building approach, with refinements meant to reflect latest costs assumptions and improved accuracy. Further details will be added in the final version of this document, once the assumptions are set.

4.5.2. Transmission investment candidates' collection data requirements

The starting point for the investment candidates' collection is the 2035 time horizon, meaning that the investment candidates should be considered on top of the starting grid for 2035 time horizon.

Real expansion candidates: Cross-border potential capacity increases - Real projects - PINT projects for the 2035 target year, to be studied during the TYNDP 2026.

Conceptual expansion candidates: Potential capacity increases can be introduced only by TSO-promoters due to specific knowledge on the grid and consequences for introduction of new candidates in the system. These candidates must be located within the **ENTSO-E + UK** perimeter.

- TSO Promoter (Yes/No) – Yes, if the project promoter is a TSO – *relevant only for real projects*

- Link name – Market Node A – Market Node B (e.g. FR00 – ES00)

- Node from – Market Node A which project connects

- Node to – Market Node B which project connects

- Name – Name of the project – *relevant only for real projects*

- ID – Project ID from TYNDP 2024 – *relevant only for real projects*

- Direct capacity increase (MW) – Net Transfer Capacity increase from Market Node A to B

- Indirect capacity increase (MW) – Net Transfer Capacity increase from Market Node B to A

- CAPEX – Capital Expenses (MEuro)

- OPEX – Operational Expenses (MEuro)

- Internal reinforcement CAPEX node from – CAPEX of required internal reinforcement in Market Node A

- Internal reinforcement CAPEX node to – CAPEX of required internal reinforcement in Market Node B

- Internal reinforcement comment - comment by TSO in case of reinforcement split

- Station from Name – Name of the substation A which project connects

- Station to Name – Name of the substation B which project connects

- RDFID (station from) – RDFID of the substation A which project connects

- RDFID (Station to) – RDFID of the substation B which project connects

In addition to this information for countries having multiple bidding zones, direct and indirect transfer capacity increases foreseen on top of the 2035 and the 2040 time horizons can be provided by the TSO.

4.5.3. Theoretical offshore candidates

In addition to real and conceptual transmission candidates submitted by project promoters, theorical offshore candidates are defined centrally by ENTSO-E as potential for connecting offshore nodes or reinforcing radial connections from offshore nodes to home markets. Theoretical candidates between offshore nodes are generated by geographical proximity and filtered by the corresponding regional groups for realistic connections. Additionally, long-distance connections between offshore nodes that have been identified as relevant by the regional groups will be added to the set of theoretical offshore candidates.

The theoretical candidates are characterised by standardized capacities with standardized cost assumptions for typical transmission assets. Depending on the topology and technology choice for a given connection total standardized CAPEX and OPEX are deducted. The standard transmission technology considered for the expansion candidates is a 525 kV DC connection with 2 GW transmission capacity with voltage source converter (VSC) technology. The expansion of transmission corridors is assumed to be using DC breaker technologies, in which the different corridors are connected through DC hubs including DC breakers. It is assumed that all technology is interoperable. It must be noted that current offshore systems may not be extendable without building new platforms due to space restrictions on the platforms. Thereby the connection of such systems with other offshore nodes implies building new platforms in addition to the electrical equipment extension.

The standardized cost assumptions are deducted from Danish Energy Agency catalogues of technology data for energy technologies and validated to be in line with the costs submitted by project promoters for real and conceptual projects. Cost assumptions per asset are given in Table 4.

		CAPEX 2025 in M€$_{2024}$/(MW*km)	CAPEX 2050 in M€$_{2024}$/(MW*km)	OPEX in %$_{CAPEX}$/a
Onshore	HVDC cable	0.0053	0.0044	1.0
Offshore	HVDC cable	0.0042	0.0035	1.0
		CAPEX 2025 in M€$_{2024}$/(MW*km)	CAPEX 2050 in M€$_{2024}$/(MW*km)	OPEX in %$_{CAPEX}$/a
Onshore	VCS	0.42	0.35	1.0
Offshore	VCS (with platform)	0.98	0.82	1.0

Table 4. Cost assumptions for offshore infrastructure assets

4.6. Economic parameters

The key assumptions on economic parameters are listed below. These parameters are of utmost importance for the expansion optimisation, for which the core objective remains an economic optimisation. These parameters are the WACC, the discount rate, the economic life, the build cost and operating costs, as well as the maximum number of units that can be built.

1. **Weighted average cost of capital (WACC)**: reflects the cost of financing investments. It is used in combination with the expected lifetime of an asset (the Economic Life parameter) to annualise

the investment cost (Build Cost parameter). For onshore and offshore real and conceptual candidates it is set as 4%. The same value is used for battery investments candidates.

2. **Discount rate**: used to discount the future costs and benefits back to the TYNDP study year (here 2026). The definition of the discount rate is important for an appraisal of the optimal investment portfolio impact, especially as not every single year between 2035 and 2050 is modelled. Adjustments of discount rates based on blocks of years is presented in section **Error! Reference source not found.**

3. **Economic Life**: the period over which project fixed costs are recovered. For onshore and offshore real and conceptual candidates it is set as 25 years.

4. **Build cost**: represents the fixed investment cost to be sustained for the project realisation. These data are provided together with investment candidates during candidates' data collection.

5. **FO&M Charge**: the annual fixed operations and maintenance cost to sustain the investment during its lifetime. These data are collected by the project promoters during candidates' data collection.

6. **Max Units Built**: refers to the upper limit on the number of units that can be built over the whole planning horizon.

5. Software tools involved

The IoSN study uses the optimisation tools Plexos and Antares to perform the expansion analysis. Models build in the tools aim to optimise the development of the European energy system and identify corresponding expansion opportunities.

5.1. Tools sanity check

As Plexos and Antares use different modelling approaches, simplified sanity checks are necessary to ensure their results remain comparable, even for more complex assessments. This section describes some of the checks and the related model adjustments for a simple dispatch model built in the two tools.

The sanity base case seen in Figure 8 shows a three-nodes system with different convential power plant and renewable capacities. All nodes are connected with modelled power lines, including an explicit modelling of capacities and impendances. Between Area 1 and Area 2 a phase shifting transformer (PST) with a nominal power of 500 MW is installed. PSTs are controllable elements in a power line that modify the phase angle difference between two nodes, thereby enabling optimized flow control. The respective phase angles can be calculated according to the following formula:

$$\theta_{max} = -\theta_{min} = P_{PST} \cdot x_{Line} \cdot \frac{360}{2\pi}$$

Where θ_{max} and θ_{min} are the upper and lower limits of the phase shift angle; P_{PST} represents the active power being controlled by the transformer and x_{Line} the series reactance of the transmission line controlled.

Lastly different electricity demands are added to each node which apply a constant load to the respective node.

Conventional Power Plants		
Type	Units [#] Area 1/ Area 2/ Area3	Marginal-Cost [€]
Gas	2/4/4	50
Hard Coal	1/2/4	55
Nuclear	4/0/4	14

Power-Line Test Cases		
Test	Line Capacity [MW]	PST Phase-Shifting Power Area 1 - Area2
1	500	500 MW
2	450	500 MW
3	Investment modelling	
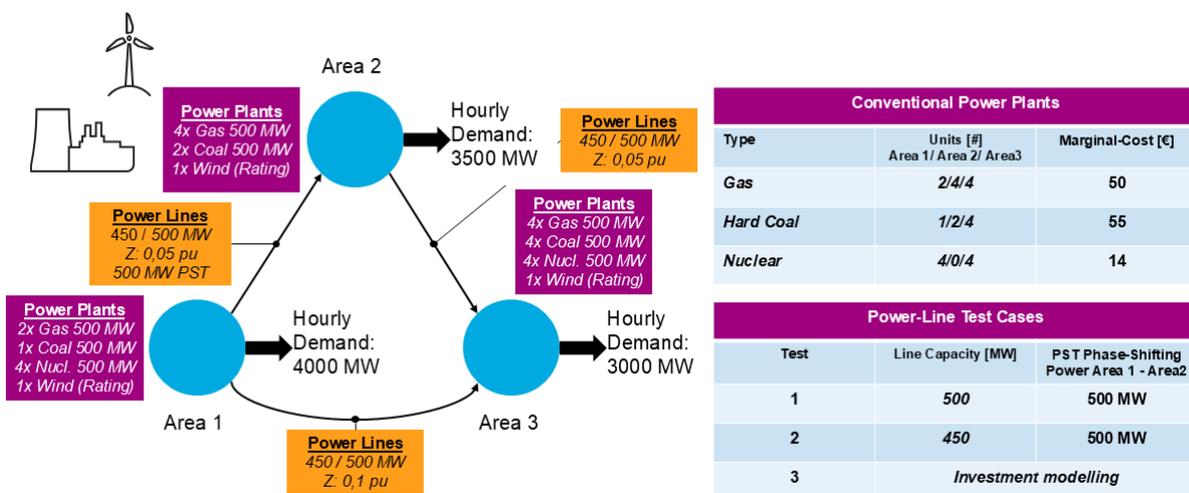
Figure 8: Base case model including relevant modelling parameters

In total two different test cases are modelled, both static dispatch tests. The two tests differ only by the fact that the maximal line capacity is decreased from 500 MW in test 1 to 450 MW in test 2.

Results dispatch test 1 (Line Capacity 500 MW)

The results of the first dispatch test can be seen in Figure 9 and Figure 10 which represent the nodes commodity balance and the corresponding average electricity price. The model results are not only compared to each other but also to the results of a reference test model from a previous IoSN-cycle, with different settings but expected to have similar behavior.
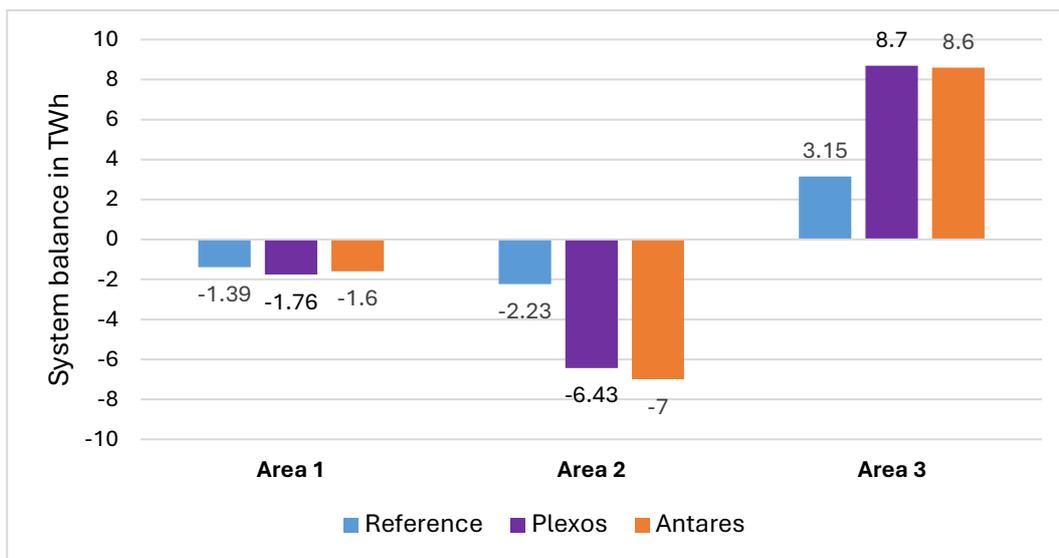
Figure 9: System balance results from test 1
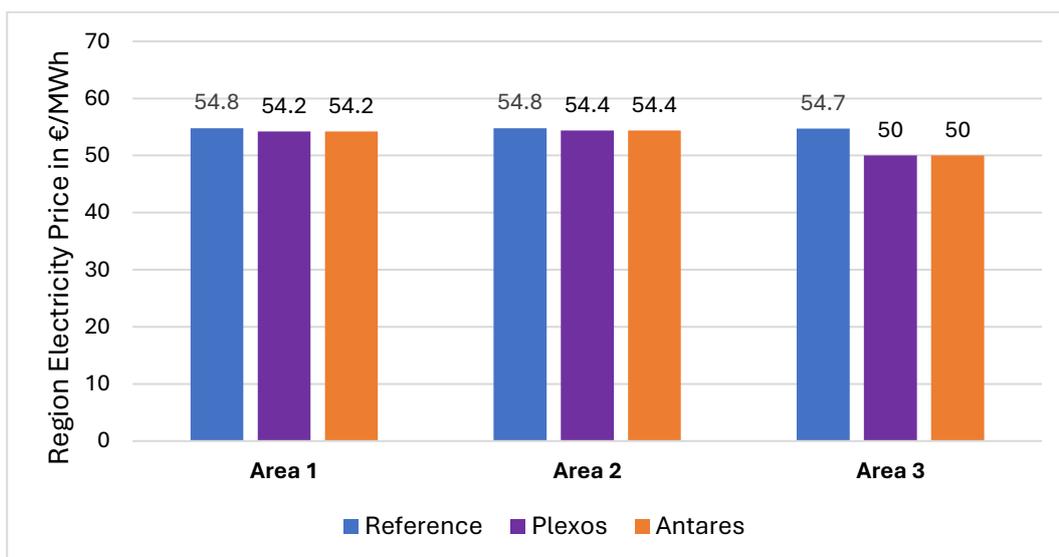
Figure 10: Electricity price results from test 1

From the comparison of the results, it is seen that Plexos and Antares are aligned for the first test case. There are some differences regarding the system balance, but these small differences can be neglected. This overall model behaviour comparison between the current versions of Plexos and Antares shows good level of alignment.

Results dispatch test 2 (Line Capacity 450 MW)

Figure 11 and Figure 12 depict the results of the second dispatch test with a decreased transmission line capacity.
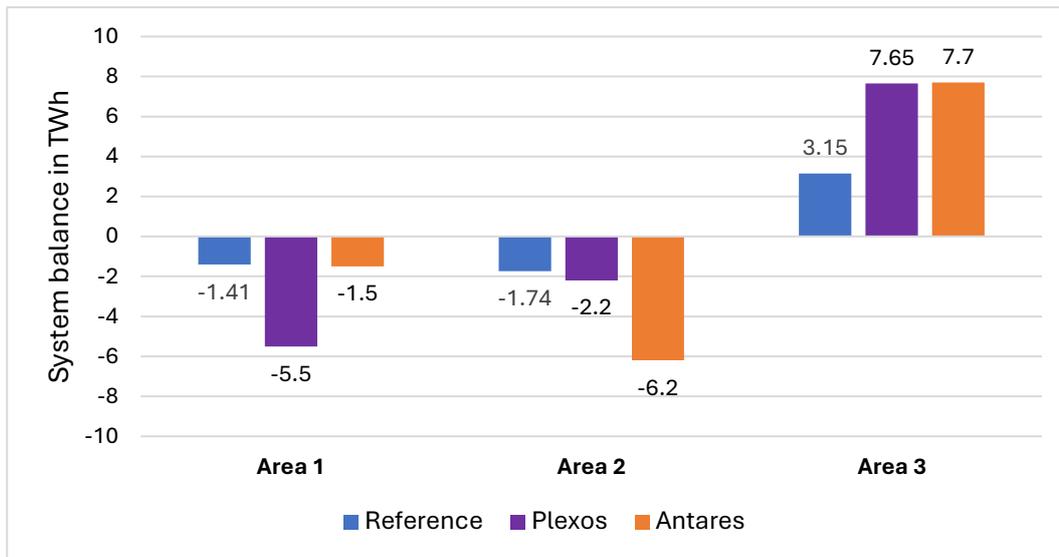
Figure 11: System balance results from test 2
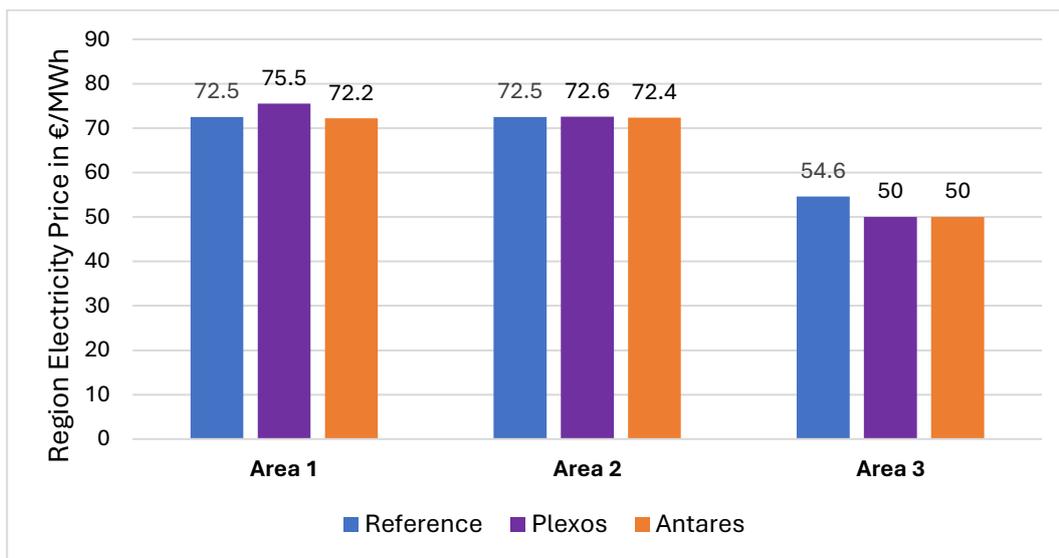
Figure 12: Electricity price results from test 2

In the second test the electricity prices between Plexos and Antares are highly aligned. The only difference between the two tools is that for Plexos the price in node 1 is higher than in node 2 in contrast to Antares. This fact also explains why the balance is switched between the models. However, regardless of the price differences, the overall balance is the same for both models. The higher prices in node 1 and node 2 result from the penalty cost of loss of load in certain hours of the optimization. The comparison of the current Plexos and Antares model with the previous sanity check text model shows the same results as in the first system test. From these tests it can be concluded that the calculations of the IoSN with the current Plexos and Antares versions should produce comparable results.

6. Annex

6.1. Zonal clustering additional details

Identification of constrained lines

To catch the first criteria of zonal clustering, it is necessary to identify the constrained lines. For that, load flow calculations have been run. By definition, a constrained line is an overloaded one. Flow calculations have been run for all the 225 kV and 400 kV lines on considered weather scenarios. On every hour, the overloaded lines are identified with their respective severity of the congestion (in MW), which is the maximum value of the flow. Some lines may be frequently constrained but with a low severity while some others are rarely overloaded but with a bigger severity. Using only the frequency as single criteria won't be enough to capture the most critical lines, neither would the severity. Hence, to combine the 2 indicators, a new criteria is used: the annual overload energy for each line which represents the sum (in MWh) of the hourly overload in the whole year. The bigger the value, the more critical the line is. An example is given below in Table 5.

Table 5: Examples of constrained lines

	Lines			Criteria used to identify the most critical line	Most critical lines
	A	B	C		
Frequency of constraints (%/year)	5	40	15	x	2, 3, then 1
Highest overload value = Severity (MW)	2000	100	3000	x	3, 1, then 2
Total annual overload energy (TWh/year)	20	10	1	x	1, 2, then 3

Clustering improvement methodology and quality indicators evolvement

The different steps of improving the clustering are:

- Identification of the gaps of the original clustering
- Calculation of flows and identification of the bottleneck and critical branches to capture (put on interzones) when it is possible
- Adaptation of the clustering by iterations of one or several adjustments

- Testing of the new proposal, drawing the results on a map and decision to keep or reject the tested modifications based on the evolvement of the indicators

Those indicators are:

- RMSE (Root Mean Square Error): For each iteration, the RMSE obtained for the tested clustering is compared to the previous one in order to see if it has improved. In that case, the changes tested are kept and the process goes on with others changes. Several iterations are made with modifications not country per country but with several changes in codependent countries. The grid reduction is done using an optimizer. The only way to improve its results is to modify adequately the clustering which is put as an input. Most of the iterations are made based on their impact on the grid reduction quality obtained after the optimization.
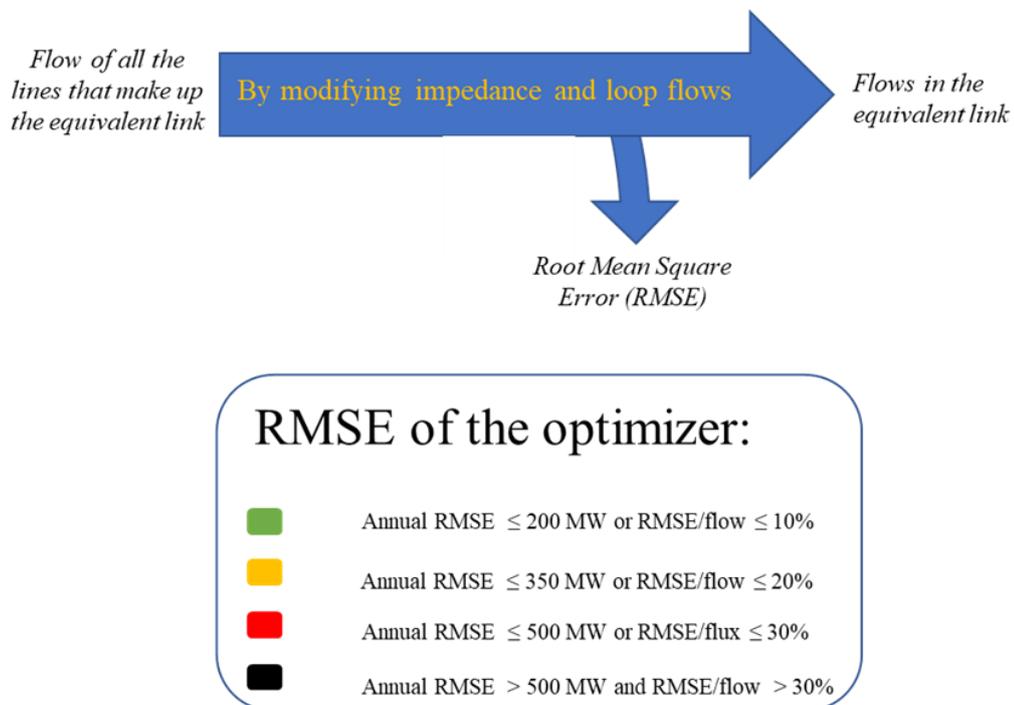

Figure 13: Schematic view of the RMSE impact on the clustering

When the criteria "RMSE" has been stabilised, the process continues with other changes looking for an improvement of the second indicator which is:

- The quality of the equivalent capacities but also its evolvement compared to the previous TYNDP quality (when the inter-zone connection existed before)
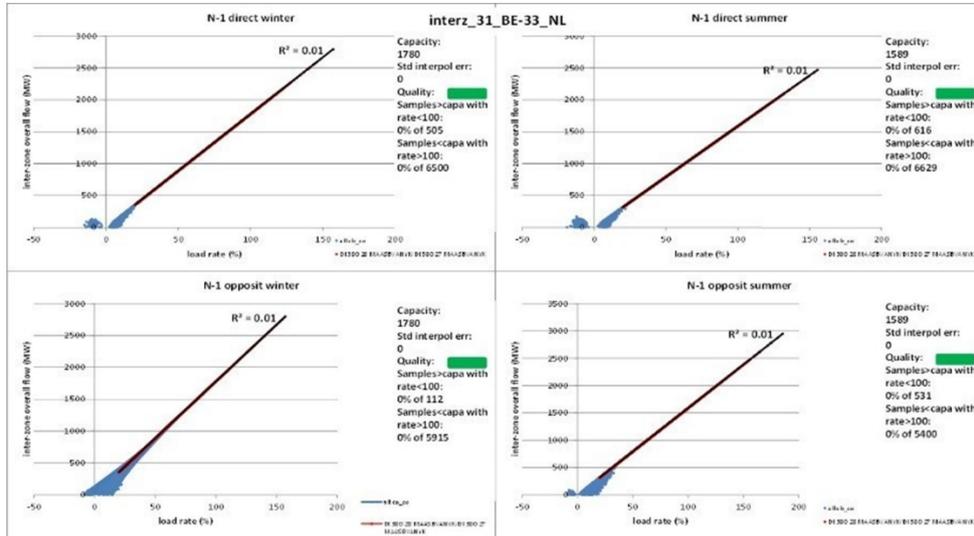
Example of capacity calculation in N/N-1 over the summer/winter and in the direct/indirect direction

Figure 14: Example of capacity calculation in N/N-1 over the summer/winter and in the direct/indirect directions

The priority was given to the "RMSE" indicator, because the capacities are calculated by tools whose parameters can more easily be adapted. The quality does not only depend on the chosen clustering, but also on how the capacities themselves are calculated: for instance, are the 225 kV lines considered as critical outages? If not, they can be ignored, to improve the capacity quality. Also, do TSOs have some topological actions to handle some critical situations? If yes, as it is not possible to directly model those, they are indirectly integrated by not taking the corresponding CBCO into account. Therefore, the main criteria to adopt changes is their ability to improve the grid reduction with RMSE. Still, their impact on the capacities is analyzed and the best clustering would be the one which could also improve the equivalent capacities quality even if it is possible to post process them for improvement.

Problematic clustering situations

In the process of reclustering, in some situations, it is quite difficult to improve the result:

- A too dense network in some areas
- A geographical boundary which, by definition, cannot be moved. In that case, the only possibility is to try to modify the clustering inside countries. On the interconnections, the only possible modification would be to separate the border into two or several more and

that would mean creating a new zone at least in one of the countries. As the number of zones has also to be limited, that is not an acceptable solution in any case

- An area with triple border. In that case, it is impossible to ensure a good reduction quality on all the borders
- Constraints on a series of lines: When several lines are constrained, it is necessary to choose to capture the most critical one which will be on the inter-zone connection.
- A lack of information on the 110 kV grid: That can be problematic when on an inter-zone connection there are only 110 kV lines without enough description. The clustering has then to be readapted to avoid that kind of situation

Network reduction: determining the equivalent impedances and zero balance flow corrections

The method used to determine the equivalent impedances is based on the calculation of an admittance matrix for the simplified system.

An extra parameter is added to the modelling: each equivalent link hosts an initial/structural flow correction, accounting for the possible asymmetries between load and generation within each cluster/area, as a result of the clustering stage. It helps to take into account the geography of load and generation localized in different stations in a same area. In fact, on a detailed network, when all the nodes are balanced, there are no flows on the links. But with a reduced grid, when all the nodes are balanced, all the load may be on the right, and all the generation on the left. That creates flows on the different links which are called zero balance flow corrections, as shown below in *Figure 12.1.3*.
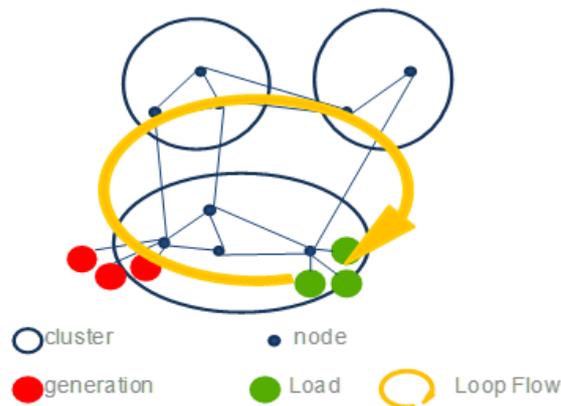
Figure 15: Example of loop flows in the detailed network

The set of impedances and flow corrections can be assessed through an optimisation problem. The method determines the optimal set of impedances and flow corrections minimizing the error between estimated flows (with the simplified grid) and target flows (with the detailed grid) on all equivalent links. There is no exact/unique solution to this optimisation due to the geography of power plant and the internal network inside every cluster. An exact solution would exist only if each electrical node was a cluster, in which case the impedance matrix would be the one of every element

of the detailed grid and there would not be any loop flow to include (except for TSO's). The result of this methodology is thus a compromise between accuracy and robustness of the equivalent grid.

The sample of synchronous physical flows we use as input of the optimisation problem can be calculated with a classical market study, with commercial exchanges at the borders (NTC simulation). The flows on the detailed grid using those data can be obtained using PTDF methodology:

o From the market study, important parameters have to be selected. Sensitivity calculations will be processed on these parameters

o Sensitivities are calculated for every parameter by increasing their values and processing a new DC load flow. Differences with the initial load flow (divided by the increase/decrease of the parameter) for all the lines of the grid will give the sensitivity matrix.

o Once the PTDF matrix calculated, flows for every hour and every line can be easily calculated by using the formula below:

$$Flow(line, \text{PIT}) = Flow(line, ref\_case) + \sum_{p \in parameters} PTDF(p, line). [market\_data(\text{PIT}, p) - market\_data(ref\_case, p)]$$

To increase the robustness of the set of impedances calculated, the setpoints of the HVDC links within the AC grid are set to 0, and the PST's are set to the neutral tap.

The network equations (in the DC approximation) can be embedded in the flow-based simulation, and thus emulate the real behaviour of the physical network through the provision to the simulator of the following linear constraints: $\forall m, \sum_{i \in m} X_i . F_i = 0$ where:

m: mesh of the simplified network

X_i: impedance of link i

F_i: Flow on equivalent link i

Network reduction: determining the equivalent capacities

Under the zonal modelling approach, the electricity system is considered as a set of zones, which act internally as copper plates that are interconnected by single-circuit connections (inter-zone connections) with a finite capacity. The capacities of these connections are calculated based on the physical characteristics and represent the physical network in the zonal configuration.

As the transfer of power between a pair of zones travels through the network according to Kirchhoff's laws, the flow between a pair of zones is not equal to the change in a power shift: some portion of the flow may follow a different route, whereas loop or transit flows created by third zones may also impose a flow on the link.

Hence, market flows between zones are determined purely by the physical consequences of dispatching power plants and loads and no longer by NTC values between zones. Rather than an NTC-based for exchanges between zones, a constraint that is used in a "traditional" market simulation, these models require an equivalent (physical) capacity value that limits the exchange between zones. This reflects the exchange of power that is possible in reality: since exceeding this value, together with an outage, would overload the physical network.

The zone-to-zone equivalent capacity must represent the physical volume of electricity that can flow from a zone to another zone. In reality, multiple lines may connect the areas that were defined as a 'zone' in the context of zonal modelling. The concept of an equivalent capacity calculation is to capture the total, physical transfer capacity of the underlying infrastructure in a single figure. This is defined as the volume of power that can be transported on all the circuits that connect the two zones physically, without violating security constraints on any of the physical lines.

The flows of all branches which interconnect two zones as well as an LODF (Line Outage Distribution Factors) matrix are used to determine an N-1 equivalent transfer capacity between a pair of zones. These equivalent capacity values for each pair of interconnected zones allows to perform market simulations, in which the flow between the zones is limited to the equivalent capacities.

For the purpose of computing an equivalent capacity, this means that the highest loaded component across the border connecting two zones can be loaded up to the point that the system is still (N-1) safe – but no further. The sum of the power that is transported by each circuit across this border, at the point where one of the circuits reached its maximum, is defined as the equivalent capacity of the connection between this pair of zones.

After defining the topological layout of the zones, a sample of load-flow calculations is used to determine the maximum possible (allowed) exchange on the circuits that physically connect one zone to another. Using data on the power transfer capacity of each physical circuit and hourly data on the flow through each circuit (relative load), the maximum possible flow from one zone to another is defined by the sum of the flows across all circuits at the point where one of the circuits reaches its 100% load rate under N-1 conditions.

The method works stepwise according to the following principles:

- Data points are divided in two directions (flow from X>Y and Y>X) and summer/winter values are separated

- The algorithm checks whether there are enough data points available at or around a 100% load rate. These are considered as "representative data points"

- Graphically speaking, this produces a scatter plot, which shows the relation between total power exchange and the highest loaded circuit at a given moment (hourly values were used)

- The equivalent capacity is defined as the flow that corresponds to the highest line loading of 100%

In the ideal case, the equivalent capacity calculation results in a clear relation between the highest line loading and the total volume of power exchanged. However, in practice, this exercise may result in other types of situations that make the definition of an equivalent capacity more ambiguous. This may be the case in the following situations:

- Single direction flow: the flow in only in one direction (i.e., there is no data for the flow in the opposite direction)

- No data points around 100% intersection: the highest loaded line is never loaded at or around 100% (i.e., within the load rate bounds mentioned above)

- Cloud of data points: there is no clear (linear) relation between highest loadings

- Single direction flow: In case the flow across a border is in a single direction for more than 99.5% of the year, it is not possible to accurately calculate an equivalent capacity in the other direction (not enough data points for calculating a representative figure). The algorithm will assume that the capacity is equal to the capacity in the other direction

- No data points around 100% intersection: Some lines never experience high load rates, and due to this there is no intersection with the 100% load rate. If there are insufficient data points above the "absolute minimum load rate" (load rate > 1%), no value is calculated. A rare situation may occur in which all data points (>99.5%) lie above the "maximum threshold" (load rate > 130%). In this case a line is fit from the origin through the average of the data points and intersected at 100%

- Cloud of data points: In this case, no clear relation can be distinguished between flow and (highest) line loadings. The algorithm will compute an equivalent capacity on the basis of the available data, but one should be cautious to use the result in further simulations. The most prudent solution to this situation is that the zonal topology is reconsidered. Depending on the situation, the solution may lie in (1) "redrawing" the borders of a zone in order to create a better grouping of similarly loaded circuits, (2) introducing additional zones, or (3) a combination of the two

Depending on the correlation between the flows on the different critical branches and critical outages of each inter-zone, the quality of the resulting equivalent capacity may be variable, which is an indicator of where it is worth improving the clustering.

6.2. List of TYNDP 2026 projects included in IoSN starting grid

ID	Project name	Direction 1	Direction 2	TYNDP2026 Dir 1 NTC	TYNDP2026 Dir 2 NTC	Status. Status ID 1 : Under Consideration, 2 : In Planning but not permitting, 3 : In permitting, 4 : Under Construction
1	RES in north of Portugal	internalPT00	0	0	0	4
4	Interconnection Portugal-Spain	ES00-PT00	PT00-ES00	1800	700	4
16	Biscay Gulf	ES00-FR00	FR00-ES00	2200	2200	4
28	Italy-Montenegro	ITCS-ME00	ME00-ITCS	600	600	4
29	Italy-Tunisia	ITSI-TN00	TN00-ITSI	600	600	4
33	Central Northern Italy	ITCN-ITN1	ITN1-ITCN	500	500	4
33	Central Northern Italy	ITCN-ITCS	ITCS-ITCN	400	400	4
35	CZ Southwest-east corridor	CZ00-DE00	DE00-CZ00	500	500	3
47	Westtirol (AT) - Vöhringen (DE)	AT00-DE00	DE00-AT00	750	250	2
81	North South Interconnector	IE00-UKNI	UKNI-IE00	981	993	4
85	Integration of RES in Alentejo	internalPT00	0	0	0	3
107	Celtic Interconnector	FR00-IE00	IE00-FR00	700	700	4

120	Princess Elisabeth Island (MOG 2)	internalBE00	0	0	0	3
121	Nautilus: multi-purpose interconnector Belgium - UK	BE00-UK00	UK00-BE00	1400	1400	2
127	Central Southern Italy	ITCS-ITS1	ITS1-ITCS	500	500	3
130	HVDC SuedOstLink Wolmirstedt to area Isar	DE00-PLI0	PLE0-DE00	150	250	3
130	HVDC SuedOstLink Wolmirstedt to area Isar	CZ00-DE00	DE00-CZ00	350	100	3
130	HVDC SuedOstLink Wolmirstedt to area Isar	CZ00-PLI0	PLI0-CZ00	0	150	3
130	HVDC SuedOstLink Wolmirstedt to area Isar	AT00-CZ00	CZ00-AT00	50	400	3
132	HVDC Line A-North	BE00-DE00	DE00-BE00	1400	0	3
132	HVDC Line A-North	DE00-NL00	NL00-DE00	250	400	3
138	Black Sea Corridor	BG00-RO00	RO00-BG00	300	200	4
144	Mid Continental East corridor	RO00-RS00	RS00-RO00	900	800	3
144	Mid Continental East corridor	HU00-RO00	RO00-HU00	450	1650	3
170	Baltic States Synchronization with Continental Europe	LT00-PL00	PL00-LT00	700	700	3
187	St. Peter (AT) - Pleinting (DE)	AT00-DE00	DE00-AT00	2500	2500	3
210	Würmlach (AT) - Somplago (IT) interconnection	AT00-ITN1	ITN1-AT00	150	150	3
219	Great Sea Interconnector	CY00-GR03	GR03-CY00	1000	1000	4
219	Great Sea Interconnector	CY00-IL00	IL00-CY00	1000	1000	4
227	Transbalkan Corridor	BA00-RS00	RS00-BA00	1050	450	3
227	Transbalkan Corridor	ME00-RS00	RS00-ME00	600	550	3
228	Muhlbach - Eichstetten	DE00-FR00	FR00-DE00	300	300	3
231	Beznau - Tiengen	CH00-DE00	DE00-CH00	100	450	2
235	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Bergrheinfeld West	DE00-DKW1	DKW1-DE00	550	1750	3
235	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Bergrheinfeld West	DE00-NL00	NL00-DE00	0	500	3
235	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Bergrheinfeld West	DE00-FR00	FR00-DE00	1300	300	3
235	HVDC SuedLink Brunsbüttel/Wilster to Großgartach/Bergrheinfeld West	AT00-DE00	DE00-AT00	0	200	3
244	Vigy - Uchtelfangen area	DE00-FR00	FR00-DE00	1500	1500	3
254	HVDC Ultranet Osterath to Philippsburg	DE00-FR00	FR00-DE00	650	100	3
259	HU-RO	HU00-RO00	RO00-HU00	2150	1050	2

260	Project 260 – Multi-purpose HVDC interconnection between Great Britain and The Netherlands	NL00-UK00	UK00-NL00	1800	2000	2
280	FR-BE: Lonny-Achene-Gramme	BE00-FR00	FR00-BE00	1000	1000	3
299	SACOI 3	FR15 - ITCO	ITCO-FR15	100	100	4
299	SACOI 3	ITCO-ITSA	ITCO-ITSA	100	100	4
299	SACOI 3	ITCN-ITCO	ITCO-ITCN	400	400	4
309	NeuConnect	DE00-UK00	UK00-DE00	1400	1400	2
313	Isar/Altheim/Ottenhofen (DE) - St.Peter (AT)	AT00-DE00	DE00-AT00	1400	1400	3
323	Dekani (SI) - Zaule (IT) interconnection	ITN1-SI00	SI00-ITN1	40	7	3
324	Redipuglia (IT) - Vrtojba (SI) interconnection	ITN1-SI00	SI00-ITN1	65	93	3
328	Interconnector DE-LUX	DE00-LUG1	LUG1-DE00	1000	800	2
329	Stevin-Izegem/Avelgem (Ventilus): new corridor	internalBE00	0	0	0	3
338	Adriatic HVDC link	ITN1-ITCN	ITCN-ITN1	600	1000	4
338	Adriatic HVDC link	ITCN-ITCS	ITCS-ITCN	1000	1000	4
339	Tyrrhenian link	ITCS-ITSIvirt	ITSIvirt-ITCS	1000	1000	4
339	Tyrrhenian link	ITSA-ITSIvirt	ITSIvirt-ITSA	1000	1000	4
339	Tyrrhenian link	ITSI-ITSIvirt	ITSIvirt-ITSI	1500	1500	4
340	Avelgem-Courcelles (Boucle du Hainaut): new corridor	internalBE00	0	0	0	3
341	North CSE Corridor	RO00-RS00	RS00-RO00	850	550	3
342	Central Balkan Corridor	BG00-RS00	RS00-BG00	550	350	2
343	CSE1 New	BA00-HR00	HR00-BA00	450	850	2
346	ZuidWest380 NL Oost	BE00-NL00	NL00-BE00	1074	447	4
349	MaresConnect	IE00-UK00	UK00-IE00	750	750	3
350	South Balkan Corridor	AL00-MK00	MK00-AL00	298	581	4
1034	HVDC corridor from Northern Germany to Western Germany	BE00-DE00	DE00-BE00	0	100	2
1034	HVDC corridor from Northern Germany to Western Germany	DE00-NL00	NL00-DE00	500	0	2
1046	Finnish North-South reinforcement	internalFI00	internalFI00	0	0	3

1052	Lienz (AT) - Malta (AT) - Obersielach (AT)	AT00-SI00	SI00-AT00	1000	450	2
1052	Lienz (AT) - Malta (AT) - Obersielach (AT)	AT00-ITN1	ITN1-AT00	500	500	2
1054	220-kV Westtirol (AT) - Zell/Ziller (AT)	AT00-DE00	DE00-AT00	750	250	2
1059	Southern Italy	ITCS-ITS1	ITS1-ITCS	200	200	3
1059	Southern Italy	ITS1-ITCA	ITCA-ITS1	900	900	3
1074	Pannonian Corridor	HU00-RS00	RS00-HU00	250	500	3
1086	Internal grid reinforcements in Estonia to increase RES connection capability (RRF project)	EE00internal	EE00internal	0	0	4
1088	Latvia and Estonia Hybrid Off-Shore interconnector	EE00-OBZ	OBZ-EE00	1000	1000	2
1095	Aurora line 2 (4th AC Finland-Sweden north)	FI00-SE01	SE01-FI00	701	883	2
1096	Beznau - Mettlen	CH00-DE00	DE00-CH00	200	1300	3
1098	Offshore Wind LT 2	LTOffshore	LTOffshore	1466	0	2
1100	Reinforcement of the existing CZ-DE interconnector (Hradec - Röhrsdorf) on the CZ side	CZ00-DE00	DE00-CZ00	500	500	3
1103	Bickigen - Chippis	CH00-DE00	DE00-CH00	400	400	3
1104	Bauler - Roost	DE00-LUG1	LUG1-DE00	800	800	2
1106	Bornholm Energy Island (BEI)	DE00-BolEnergy	BolEnergy-DE00	0	0	2
1110	Sicily - Calabria	ITCA-ITSI	ITSI-ITCA	450	700	3
1112	GRITA 2	ITS1-GR00	GR00-ITS1	1000	1000	2
1121	220-kV Hessenberg (AT) - Weißenbach (AT)	ATInternal	ATInternal	0	0	2
1122	Offshore Wind connection Centre Manche 1	FROffshore	FROffshore	0	0	3
1123	Offshore Wind connection Centre Manche 2	FROffshore	FROffshore	0	0	3
1124	Offshore Wind Connection South Brittany	FROffshore	FROffshore	0	0	3
1125	Offshore Wind Connection Occitanie (Narbonnaise)	FROffshore	FROffshore	0	0	2
1126	Offshore Wind Connection PACA (Golfe de Fos)	FROffshore	FROffshore	0	0	2
1127	Offshore Wind Connection South Atlantic Oléron 1	FROffshore	FROffshore	0	0	2
1138	400 kV OHL Suceava (RO) - Balti (MD)	MD00-RO00	RO00-MD00	300	300	2
1153	PST romands	CH00-FR00	FR00-CH00	800	800	2

1155	380-kV Burgenland North (AT) - Sarasdorf (AT) - Greater Vienna (AT)	ATInternal	ATInternal	0	0	2
1157	HG North Tyrrhenian Corridor	ITCS-ITN1	ITN1-ITCS	2100	2100	2
1157	HG North Tyrrhenian Corridor	ITCS-ITCN	ITCN-ITCS	800	0	2
1159	220-kV Bisamberg (AT) – Wien Südost (AT)	ATInternal	ATInternal	0	0	2
1160	PST Riddes	CH00 - ITN1	ITN1 - CH00	150	100	4
1161	Offshore Wind Connection South Atlantic Oléron 2	FR00Offshore	FR00Offshore	0	0	1
1162	Offshore Wind Connection Fécamp-Grand Large 1	FR00Offshore	FR00Offshore	0	0	1
1166	HG Adriatic Corridor	ITCN-ITN1	ITN1-ITCN	700	700	2
1166	HG Adriatic Corridor	ITCS-ITS1	ITS1-ITCS	600	600	2
1166	HG Adriatic Corridor	ITS1-ITN1	ITN1-ITS1	2100	2100	2
1167	HG Central link	ITCS-ITCN	ITCN-ITCS	600	600	2
1182	EHV S/S Thesprotias and its connection to the 400 kV System	AL00-GR00	GR00-AL00	1160	1590	2
1183	New interconnection line 400 kV Greece - Albania	AL00-GR00	GR00-AL00	160	590	2
1185	Powering Up Offshore South Coast project	IE00Offshore	IE00Offshore	0	0	2
1209	Latvia and Lithuania cross-border strengthening project	LT00-LV00	LV00-LT00	949	1570	2
1219	Bofferdange- Bertrange	LUG1INternal	LUG1INternal	0	0	3
1229	Rhein-Main-Link	BE00-DE00	DE00-BE00	700	450	3
1229	Rhein-Main-Link	DE00-DKW1	DKW1-DE00	850	700	3
1234	220-kV Reitdorf (AT) - Weißenbach (AT)	ATInternal	ATInternal	0	0	4
1235	Second circuit of the 400 kV OHL Sajóivánka (HU) – Rimavská Sobota (SK)	HU00-SK00	SK00-HU00	100	1137	2
1256	Limitations removal on the Italian - Slovenian border	SI00-ITN1	ITN1-SI00	600	600	2

6.3. Weather scenario selection methodology

Energy investment decisions must account for uncertainty in demand, generation, and policy changes. The stochastic nature of the Monte Carlo years in IoSN study reflects the impact of uncertainties in key system parameters. Among those, the most distinct ones are:

- electricity demand variations, driven by temperature fluctuations and economic factors,
- renewable energy generation, particularly wind and solar power fluctuations,
- hydraulic inflows, affecting hydroelectric generation potential.

Those system parameters are directly linked to the selection of the weather scenario conditions for the optimization study. For the TYNDP 2026 cycle ENTSO-E is using a common weather scenario selection approach adopted also for the Scenario Building and Cost-Benefit Analysis phases.

The methodology for the selection of those weather Scenarios, the following inputs (variables are used):

Table 6: Weather Scenario Selection Input Variables

VARIABLE	RESOLUTION	SPATIAL UNIT
WIND ONSHORE CAPACITY FACTOR TIME SERIES	Hourly	PECD Zone
WIND OFFSHORE CAPACITY FACTOR TIME SERIES	Hourly	PECD Zone
SOLAR PV (COMBINED) CAPACITY FACTOR TIME SERIES	Hourly	PECD Zone
HYDRO RESERVOIR INFLOW	Weekly	PECD Zone
HYDRO RUN-OF-RIVER INFLOW	Weekly	PECD Zone
HDD/CDD COMBINED	Daily	Country (market zone)

HDD/CDD calculation

Heating and Cooling degree days are variables calculated based on the population based hourly temperature time series. HDD and CDD are calculated for each region as follows:

$$HDD = t_{threshold_{heating}} - t_{average} \ \forall \ t_{threshold_{heating}} > t_{average} \ otherwise \ 0$$

$$CDD = t_{average} - t_{threshold_{cooling}} \; \forall \; t_{threshold_{cooling}} < t_{average} \; otherwise \; 0$$

$t_{threshold_{heating}}$ … temperature threshold, below which heating is necessary, eg. 12.3°C[10] for AT

$t_{threshold_{cooling}}$ … temperature threshold, above which cooling is necessary, eg. 25.5°C[1] for AT

$t_{average}$… average daily temperature

6.3.1. Scope of Analysis

- **Target Years & Windows**: 2030 (2026–2035), 2035 (2031–2040), 2040 (2036–2045), 2050 (2046–2055).
- **Climate Models**: CMR5, MEHR, ECE3.
- **Total Candidates per Target**: 3 models × 10 years = 30 climate-year series.
- **Selection Outcome**: For each target, identify 3 representative series (climate model + year).

6.3.2. Overview

The process involves several key steps:

1. **Calculating Average Values, cumulative anomalies for Weather Scenario:** This establishes a baseline value for each year within a given weather scenario. This is crucial for identifying trends and anomalies.
2. **Calculating Overall Average and Standard Deviation and Deltas:** These values are used for normalization, ensuring that the parameters are comparable across different scenarios. Normalization is essential for meaningful comparisons and analysis.
3. **Calculating Weighting Factors:** These factors account for regional differences in installed capacity. Weighting ensures that regions with higher capacity have a proportionally larger influence on the final results.
4. **Normalizing Parameters:** This involves subtracting the minimum and dividing by the standard deviation for each parameter. Normalization brings all parameters to a similar scale, facilitating PCA and K-Means analysis.
5. **Applying PCA and K-Means:** These techniques are used to reduce the dimensionality of the data and group similar scenarios. This simplifies analysis and allows for the identification of key patterns.

6.3.3. Detailed Steps

1. Calculate Yearly Average Values

1. For each weather scenario and each target year, identify the average value from the 365 daily values, 53 weekly, hourly 8760 values

    Calculation of Average: $\mu_{v,r,y,m} = \frac{1}{T}\sum_{t=1}^{T} x_{v,r,y,m}(t)$

    $\mu_{v,r,y,m}$: annual mean of variable v in region r for year y and weather scenario m;
    T: number of time steps in the year;

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[10] *According to DFT (with update for Italy)*

$x_{v,r,y,m}(t)$: value of variable v at time t.

Calculation of Cumulative Anomaly: $CA_{v,r,y,m} = \sum_{t=1}^{T}\left[x_{v,r,y,m}(t) - \overline{x_{v,r}}(t)\right]$

$CA_{v,r,y,m}$: cumulative anomaly for variable v;
$x_{v,r,y,m}(t)$: variable value at time t;
$\overline{x_{v,r}}(t)$: multi-model average at time t.

2. Store these average values, creating a new dataset where each target year has a single average value associated with it.

2. Calculate Overall Average, Standard Deviation and Deltas

1. From the set of yearly average values calculated in Step 1, determine the overall average value across all years.

2. Calculate the standard deviation of the yearly average values.

Calculation of Aggregate Mean: $\mu_{v,r}^{tot} = mean_{y,m}\left(\mu_{v,r,y,m}\right)$

$\mu_{v,r}^{tot}$: overall mean of μ_{v,r,y,m} across all years y and weather scenarios m.

Calculation of Aggregate Std: $\sigma_{v,r}^{tot} = std_{y,m}\left(\mu_{v,r,y,m}\right)$

$\sigma_{v,r}^{tot}$: standard deviation of $\mu_{v,r,y,m}$ across all years y and weather scenarios m.

Calculation of Deltas: $\Delta\mu_{v,r,y,m} = \mu_{v,r,y,m} - \mu_{v,r}^{tot}; \Delta\sigma_{v,r,y,m} = \sigma_{v,r,y,m} - \sigma_{v,r}^{tot}$
$\Delta\mu_{v,r,y,m}$: deviation of annual mean from aggregate mean;
$\Delta\sigma_{v,r,y,m}$: deviation of annual std from aggregate std.

3. Calculate Weighting Factors

1. For each region and target year, sum the installed capacity for relevant renewable energy sources (e.g., wind, solar).

2. Divide the regional sum by the total sum of installed capacity across all regions. This result is the weighting factor for that region and target year

3. Repeat this process for each region and target year.

Regional Weighting Factor: $w_{r,y} = \frac{B_{r,y}}{\sum_r B_{r,y}}$

$w_{r,y}$: weight for region r in year y;
$B_{r,y}$: base metric (e.g., capacity or load) for region r.

Weighted Deltas: $\Delta\mu_{v,r,y,m}^{w} = w_{r,y}\Delta\mu_{v,r,y,m}; \Delta\sigma_{v,r,y,m}^{w} = w_{r,y}\Delta\sigma_{v,r,y,m}$

- Weighted deviations: multiply deltas by regional weight $w_{r,y}$.

- **Tip:** Ensure that the installed capacity data corresponds to the correct target year.

- **Alternative Approach:** If regional data is unavailable, consider using country-level data instead.

- **Warning:** Exclude regions not included in the analysis (e.g., Turkey, Ukraine, Moldova).

4. Normalize Parameters

1. For each target year's average value, subtract the overall average calculated in Step 2.

2. Divide the result by the standard deviation calculated in Step 2. This normalized value represents the standardized anomaly for that year.

3. Repeat this process for all parameters.

Normalization: $Z_i = \frac{\Delta_i^w - mean(\Delta^w)}{std(\Delta^w)}$

Z_i: standardized weighted delta for series i; $mean(\Delta^w)$,
$std(\Delta^w)$: mean and standard deviation of weighted deltas across all series.

5. Apply PCA and K-Means

1. Create a table with the normalized parameters for each weather scenario.

Year	a_Var1	SD_Var1	a_Var2	SD_Var2	...	a_Var12	SD_Var12
WY01	...	...	...	...	...	...	...
WY02	...	...	...	...	...	...	...
...	...	...	...	...	...	...	...
WY30	...	...	...	...	...	...	...

2. Use PCA to reduce the number of parameters (e.g., from 6 to 2).

Year	a_Var1	SD_Var1
WY01	-0.12	0.45
WY02	0.08	-0.34
...	...	...
WY30	1.21	-0.77

The loadings show how much each original variable contributes to the principal components. This helps you understand what each component represents. For example, the loadings might look like this:

Variable	PC1	PC2	PC3	...
a_Var1	0.45	0.10	-0.32	...
SD_Var1	0.42	-0.20	0.21	...
a_Var2	0.48	0.05	-0.19	...
SD_Var2	0.12	0.40	0.07	
...	...	...	...	...

This tells you, for example, that PC1 is largely driven by a_Var1, SD_Var1 and a_Var2.

3. Apply K-Means clustering to group similar weather scenarios

After dimensionality reduction via PCA, the goal of k-means clustering is to partition the 30 normalized, weighted-climate-year vectors (two-dimensional PCA scores) into three distinct clusters. Each resulting cluster corresponds to a representative climate-year series for the target.

Algorithm Execution

- o Choose k=3k = 3k=3.
- o Initialize three centroids, e.g. by k-means++ or random selection.
- o **Iterate** until convergence:
    1. **Assignment step**: assign each row of PPP to the nearest centroid via Euclidean distance.
    2. **Update step**: recompute each centroid as the mean of all points assigned to it.

Centroid Identification

- o After convergence, obtain centroids

Representative Years

- o For each centroid compute the Euclidean distance to every series
- o Select the climate-year series minimizing
- o The three indices form the set of representative years.

Illustrative Graph
The figure below illustrates k-means clustering on synthetic PCA scores (30 points) into three clusters (colors), with centroids marked "×". In practice, each point represents a climate-year series; its cluster determines which three series are selected.
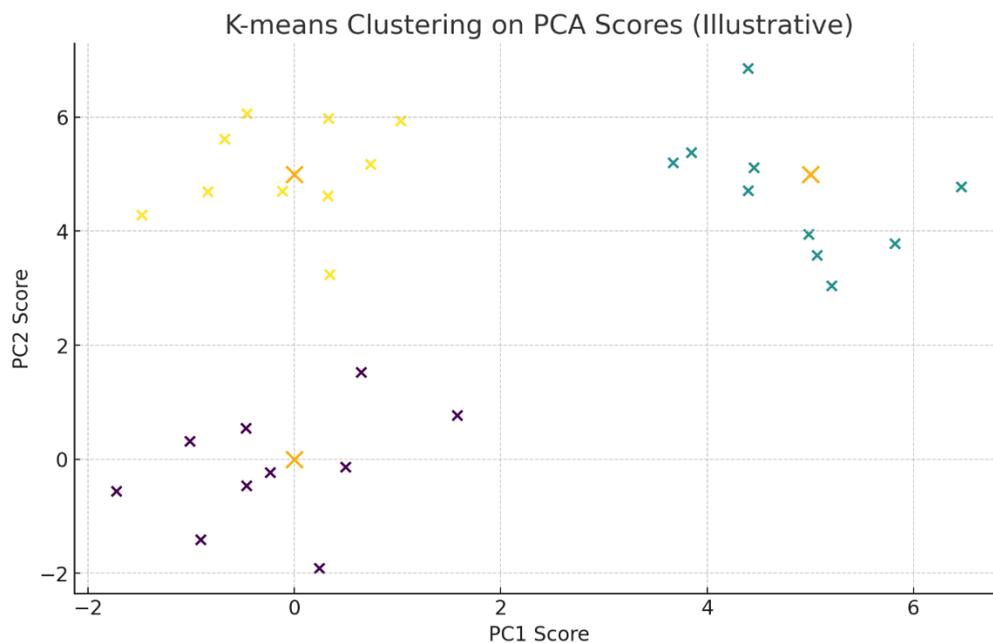

Figure 16 Illustration of the K-means Clustering analysis outcomes based on PCA variable scores

7. Glossary

AC (Alternating Current)
Type of electric current used in most transmission and distribution systems, characterised by periodically reversing direction.

CAPEX (Capital Expenditure)
Investment costs associated with building new infrastructure, such as transmission lines, converters, offshore cables, or storage assets.

Clustering (Zonal Clustering)
Process of aggregating detailed network nodes into a limited number of zones while preserving key electrical characteristics and constraints, used to create a reduced but representative network model.

Conceptual Candidates
Theoretical infrastructure options that are not linked to specific, concrete projects but represent potential system development pathways within predefined technical or geographical limits.

Cross-Border Capacity
Transmission capacity enabling electricity exchanges between different bidding zones or countries.

DC Load Flow Approximation
Simplified representation of power flows assuming linear relationships between flows and voltage angles, commonly used in large-scale planning models.

Electrolyser
Facility that converts electricity into hydrogen via electrolysis, providing a coupling between the electricity and hydrogen systems.

ENTSO-E
European Network of Transmission System Operators for Electricity, responsible for coordinating electricity system operation and planning at the European level.

Expansion Optimisation
Mathematical optimisation process used to identify cost-efficient combinations of infrastructure investments that meet future system needs under defined constraints.

Identification of System Needs (IoSN)
Analytical process within the TYNDP used to identify where additional electricity transmission, offshore infrastructure, and storage can provide system-wide benefits.

Infrastructure Gaps Report
TYNDP output that presents the results of the IoSN analysis, highlighting gaps between future system needs and existing or planned infrastructure.

Kirchhoff's Laws
Fundamental electrical laws governing current balance at nodes (first law) and voltage relationships around loops (second law), used to model physical power flows.

LODF (Line Outage Distribution Factor)
Indicator used to estimate how power flows redistribute across a network following the outage of a transmission line.

LP (Linear Programming)
Optimisation technique where relationships between variables are linear, used to solve large-scale planning problems efficiently.

Market Modelling
Simulation of electricity supply, demand, and prices under defined scenarios to assess system operation and economic outcomes.

NTC (Net Transfer Capacity)
Maximum amount of electricity that can be exchanged between two bidding zones while respecting security constraints, traditionally used in cross-border modelling.

Offshore Corridor
Transmission infrastructure connecting offshore renewable generation to onshore grids and/or linking multiple countries, potentially in radial or hybrid configurations.

ONDP (Offshore Network Development Plan)
ENTSO-E planning framework focused on offshore electricity infrastructure and its integration with onshore systems.

OPF (Optimal Power Flow)
Optimisation approach that determines the most economical system operation while explicitly considering network constraints and physical power flow laws.

OPEX (Operating Expenditure)
Costs incurred during the operation of assets, including fuel costs, variable operation and maintenance, and other running expenses.

Pan-European Climate Database (PECD)
Dataset providing climate-based time series for demand, renewable generation, and hydropower inflows used in TYNDP analyses.

Pan-European Market Modelling Database (PEMMDB)
Central database containing market, technical, and economic data for generation, demand, storage, and flexibility assets across Europe.

Post-Processing
Analytical step following optimisation used to filter out marginal or unrealistic investment outcomes and ensure robustness of results.

Robust Optimisation
Optimisation approach that accounts for uncertainty by identifying solutions that perform well across multiple scenarios, such as different weather conditions.

Scenario Building
Process of defining consistent future assumptions for demand, generation, technologies, and policies used in TYNDP analyses.

Storage (Electricity Storage)
Technologies that store electrical energy for later use, such as batteries or pumped hydro storage, providing flexibility to the power system.

Target Years
Future time horizons assessed in the TYNDP 2026 IoSN: 2035, 2040, and 2050.

TYNDP (Ten-Year Network Development Plan)
ENTSO-E's pan-European planning product.

Value of Lost Load (VoLL)
Economic parameter representing the cost to society of unserved electricity demand, used to penalise load shedding in optimisation models.

Weather Scenario
Set of climate-derived time series representing a specific combination of meteorological conditions affecting demand and renewable generation.

Zonal Model
Electricity market and network representation in which each zone is treated as a copper plate, with physical constraints represented between zones rather than at every individual node.