



MANOEUVRE

Energy System Modelling for Transition to a net-Zero 2050 for EU via
REPowerEU

Man0EUvRE – Deliverable 3.1

Executive Summaries of Case Studies

Final Version 2.0

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List of Acronyms and Abbreviations

Term	Explanation
ABM	Agent-Based Modelling
ATR	Autothermal Reforming
IAMs	Integrated Assessment Models
BECCS	Bioenergy with Carbon Capture and Storage
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDP	Communication and Dissemination Plan
CETP	Clean Energy Transition Partnership
CHP	Combined Heat and Power
CS	Case Study
CST	Concentrated Solar Thermal
DMP	Data Management Plan
ECEMF	European Climate and Energy Modelling Forum



EERA	European Energy Research Alliance
ESMs	Energy System Models
ESR	Effort Sharing Regulation
EU	European Union
FEC	Final Energy Consumption
IEA-ETSAP	International Energy Agency - Energy Technology Systems Analysis Program
LULUCF	Land Use, Land-Use Change and Forestry
MIBEL	Iberian electricity market
NEP	National Energy Plan
NECP	National Energy and Climate Plan
PHS	Pump Hydro Storage
PPA	Power Purchase Agreements
PtX	Power-to-X
RED	Renewable Energy Directive
REPowerEU	European Commission plan to phase out Russian fossil fuel imports
SMR	Steam Methane Reforming
TES	Thermal Energy Storage
UC	Unit Commitment
VRE	Variable Renewable Energy
vRES	Variable Renewable Energy Sources
WP	Work Package

Executive Summary

European energy systems across the case studies collectively show that Europe can become both self-reliant and an exporter of low-carbon energy carriers if policies and investments unlock regional strengths and the right flexibility instruments are put in place. Southern states with abundant solar energy (e.g. Portugal, Spain, Greece, Turkey) can scale renewables and electrolysis. Scandinavia's hydropower offers system-scale flexibility that stabilises high variable renewable energy (VRE) penetration, and cross-model comparisons demonstrate that combining broad, cross-sectoral modelling with detailed power-system studies reveals complementary roles for exports, seasonal storage and short-term balancing. Studies of Germany and Hungary underline the critical role of dispatchable, negative-emission options—such as bioenergy with carbon capture and storage (BECCS)—to avoid reliance on fossil backstops, while agent-based macroeconomic results show that changing global energy factor prices will reshape (not necessarily hollow out) industrial activity.

To turn these findings into a resilient, independent, and clean European energy system, policymakers should pursue a coordinated, portfolio-based strategy: **(1)** accelerate large-scale renewables and electrolyser deployment, especially in resource-rich regions in south, while simultaneously investing in export infrastructure (ports, pipelines, long-duration storage and interconnectors) and harmonised



certification for renewable hydrogen and synthetic fuels; **(2)** enhance market designs and revenue-support to reduce revenue cannibalisation and ensure sufficient incentives for both generation and diverse flexibility providers; **(3)** prioritise flexibility across timescales (by leveraging hydropower, thermal storage, batteries and demand response through explicit procurement and market signals) and integrate sector coupling so surplus VRE can be stored as hydrogen or synthetic fuels; **(4)** protect and scale dispatchable low-carbon options such as sustainably sourced BECCS to preserve system security during low wind and solar periods; **(5)** align industrial policy and labour measures to capture *renewable-pull* opportunities so Europe retains value-added production; and finally **(6)** fund research and development, pilots and EU-level coordination to manage infrastructure risks and ensure equitable, timely deployment. Together, these actions would maximise renewable integration, secure clean industrial competitiveness, and strengthen European energy independence. In this report, some case studies shared their results, which are expected to be finalised in the second version of the executive summary during the first quarter of 2026. The details of each case study are as follows:

CS1: This case study assesses Spain's potential to contribute to European energy self-sufficiency across three key dimensions: green hydrogen production, thermal energy storage, and industrial decarbonisation. Using the *TIMES-Sinergia* model, four energy transition scenarios (GoRes, NECP Essentials, REPower++, and TrinityEU) were developed and compared with the *GENESYS-MOD* model and the Spanish NECP.

Results demonstrate that Spain can become a net exporter of green hydrogen, with a positive balance of approximately 240 petajoules (PJ) by 2050, leveraging abundant renewable resources and an electrolysis-focused strategy. Infrastructures will play a crucial role and can constrain exports. Regarding concentrated solar thermal with thermal energy storage, modest but increasing penetration is observed in industrial sectors including construction, pharmaceuticals, and food processing. Thermal storage proves essential for extending operating hours beyond peak solar availability and reducing fossil fuel backup requirements.

CS2A: This case study examines how Norway and Sweden can decarbonise their closely connected energy systems while also contributing to the European energy transition, by providing low-carbon energy commodities such as electricity and hydrogen, and energy-intensive green industrial products, such as iron, steel and aluminium. Four scenarios are modelled and analysed in the case study using the *TIMES-NOSE* energy system model; combining two possible industry developments in Norway and Sweden with two EU EnVis2060 scenarios, GoRES and Trinity.

The outcomes show that Norway and Sweden can contribute significantly to the European energy transition beyond their borders, but that their roles differ across scenarios. In low-demand scenarios, both countries primarily export electricity and hydrogen, while in high-demand scenarios with strong green industrial growth, exports shift toward energy-intensive products and synthetic fuels rather than energy commodities. Finally, the cost-reductions in green hydrogen and renewables in GoRES, contribute to significant green hydrogen exports to Europe.

CS2B: Using the power system model *FanSi* with a Northern European dataset, focusing in particular on Norway, this case study assesses how various flexibility sources shape system dynamics. It places special emphasis on the role of hydropower as a stochastic storage solution in supporting VRE, while also examining alternative flexibility options that could provide similar services.



The results provide new insights into the challenges of moving from broad, cross-sectoral models to more detailed, sector-specific analyses, and demonstrate how these approaches can complement and strengthen one another. FanSi simulations show that hydropower flexibility can be widely deployed to balance the diurnal variability of solar generation outside the winter season, thereby reducing variability spillovers from solar-rich neighbouring regions.

CS3: This case study investigates how the global shift from fossil to renewable energy inputs reshapes the competitiveness of energy-intensive industries and, in turn, affects industrial energy demand across Europe. Using a stock-flow consistent agent-based macroeconomic model calibrated to the EXIOBASE multi-regional input-output database, it simulates how heterogeneous renewable energy potentials alter relative production costs and trigger firm relocation across countries and sectors.

Results show that energy cost shocks propagate through production networks well beyond directly energy-intensive sectors. Most European countries experience moderate aggregate energy demand deviations of 5–15% from the baseline; however, marked structural reorganisation occurs within regional industry compositions. Countries with strong renewable endowments — particularly Spain, France, Denmark, and Norway — tend to attract industrial activity, while countries with less favourable cost profiles, such as Poland, face stronger outflows. A key finding is that these adjustments operate primarily through sectoral restructuring and relocation rather than through uniform aggregate demand shifts, underscoring the need to incorporate endogenous industrial dynamics into national and European energy transition scenarios.

CS4: In this case study, we analyse the effect of an increasingly flexible power demand on the refinancing conditions in the German power sector. The results show that a higher flexible electricity demand can contribute to the stabilisation of market values for renewable energy sources. On the contrary, we find that higher degrees of flexibility make it harder for the flexibility technologies themselves to recover their costs. This is due to the mutual revenue cannibalisation of flexibility technologies. For some scenarios, renewable energy sources cannot fully recover their costs. In addition, for some scenarios flexibility cost recovery is also below 100%. While parts of this is due to model limitations, it still raises the question of whether sufficient capacity would have been built without adequate de-risking measures and additional revenue streams, e.g. from state-administered support. However, answering this question is beyond the scope of the prevailing analysis as investments are not explicitly modelled in this case study.

CS5: In this case study, we model the German bioenergy system within the European energy system. Our analysis using *BENOPTex* shows that the expansion of variable renewable energy sources may lead to system instability without the presence of dispatchable energy. Because bioenergy can both generate power and remove atmospheric emissions through carbon capture and storage, it represents a promising option that should be actively promoted. In the absence of bioenergy, risk-averse policymakers may rely on fossil fuels, jeopardising the achievement of climate targets. We also find that under conditions of low solar and wind availability, bioenergy becomes more attractive from a cost-optimality perspective, with total system costs increasing by less than 10%. Comparing the NECP and REPowerEU++ scenarios for Germany from the EU EnVis 2060 shows higher capacities of variable renewables in the NECP scenario, reflecting efforts to meet the targets. We also examine the Hungarian energy



system and observe that the current National Energy and Climate Plan does not fully exploit the available bioenergy potential (as well as wind energy) and is relatively lenient in its approach to renewable integration.

CS6: The aim is to examine how hydrogen-based energy storage and power conversion can support Turkey's transition to a cleaner and more flexible energy system, while also contributing to Europe's long-term climate and energy goals. The study evaluates how hydrogen can link electricity and gas networks, provide seasonal storage, and supply energy for transport, residential heating, and electric vehicle demand through integrated modelling of Turkey and Europe. Our results show that by 2050, renewable electricity supported by hydrogen systems can supply more than 63% of Turkey's total final energy use. Surplus solar and wind generation is converted into hydrogen, stored for long periods, and then used to produce electricity during winter or periods of low renewable output. This reduces fossil fuel consumption by approximately 35% compared with 2020 levels. Electrolyser capacity increases to about five gigawatts in 2035, in line with national targets, and continues toward seventy gigawatts by 2053. With this scale of clean hydrogen production, Turkey can begin exporting up to half a million tonnes (16.67 TWh) of renewable hydrogen each year to European markets. Through these outcomes, case study 6 demonstrates how integrated hydrogen pathways can strengthen energy security, reduce emissions, and deepen cooperation between Turkey and Europe.

CS7: It examines Greece's potential to become a medium- and longer-term renewable energy hub within the European-MENA region. In this study, Greece's potential for domestic production, transportation, and (re-)export of various energy carriers, including renewable electricity, green hydrogen, synthetic fuels, and green ammonia, was assessed using an enhanced version of the PRIMES model. To this end, an energy system analysis was conducted on the results of four scenarios, each based on the GoRES EnVis scenario for the electricity demand and the Greek NECP projections of hydrogen and synthetic fuels production, while further examining the impact of different levels of potential demand, hydrogen pipelines and HVDC connections availability with neighbouring countries on Greece's energy system. Results show that Greece can in principle become both an electricity and a hydrogen exporter, but a hydrogen export-oriented direction showed more stable revenues and less volatility on prices and grid constraints than the electricity export route. The outcomes of the analysis can be considered as complementary to the Greek NECP, emphasizing long-term strategies that are interconnected with market evolution and infrastructure developments, such as investment requirements, renewable capacity expansion and flexibility needs, planning for electrolyzers, synthetic fuel production, and export infrastructure. This shift to a highly renewable-based, hydrogen-enabled energy mix is also tied to and influencing a reshaping of electricity pricing and market design, as renewable energy dominance causes a significant drop in electricity prices.

CS8: In this case study, the last version of the French NECP has been analysed in detail and compared with the EnVis-2060 NECP Essentials v1.2 scenario. Although the total final energy values are consistent, the disaggregation per energy vectors and energy sectors shows significant deviations, in particular: (i) The consumption of the industry, residential and transport sectors are underestimated, while the power consumption for specific uses of electricity is overestimated in EnVis; (ii) Gas consumption is overestimated, particularly in the buildings sector, until 2035 but underestimated afterwards; (iii) Coal consumption is



overestimated; (iv) The power sector displays some deviations: the coal phase-out appears too late in EnVis, and the gas and oil use is overestimated. Regarding renewables, there is too much wind power and not enough PV in EnVis, compared to the NECP; (v) Finally, electrification efforts are far less ambitious in EnVis than in the NECP. Updates to the GENeSYS-MOD input dataset have been proposed and discussed. The power system *plan4res* model has then been used to simulate in depth the EnVis NECP Essentials scenario for the year 2030.

CS9: In this case study, the last version of the Portuguese NECP 2030 from 2024 is analysed in detail and a series of simulations was carried out to assess the impact of different flexibility solutions in a first step. Using the *Dispa-SET* dispatch model, simulations were performed to evaluate the hourly operation of the power system, capturing demand variations, renewable generation profiles, and the role of stationary storage, sector-coupling and demand-side flexibility. The results show that flexibility type and scale affect power system reliability and costs: batteries reduce frequent small deficits, hydrogen electrolyzers cut curtailment if large enough, and demand flexibility lowers electricity costs. To ensure system security, flexible solutions should align with predictable daily demand, and conventional plants may need to operate outside optimal dispatch. Overall, the 2030 NECP renewable targets are technically feasible with careful planning of system flexibility. In a second step, the evaluation of the performance of the MIBEL's day-ahead market from 2030 to 2050 was performed using GENeSYS-MOD v1.2 outcomes. The results highlight strong growth of variable renewable energy sources (vRES) through 2050, particularly solar photovoltaic, and the resulting price cannibalisation that challenges the economic viability of solar generation in a market environment. Wind generation, in contrast, maintains more stable capture prices showing differences in the market value across vRES technologies. A carefully designed transition pathway, by integrating a balanced generation mix, robust flexibility solutions, and reinforced cross-border interconnections between Portugal and Spain, is essential.

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Introduction

This report includes nine case studies from various countries. Each case study addresses a question from a regional perspective while considering the general assumptions of the consortium through established scenarios. Although the case studies provide detailed insights within their respective regions, they have limited visibility of systems outside their boundaries. To address this, monthly “jour fixe” meetings were held, during which partners exchanged information, shared their results, and integrated regional findings into the European energy optimisation model (GENeSYS-MOD). We follow a consistent reporting format across all case studies, allowing readers who are interested in a specific region or question to skip other cases without losing essential context. Finally, the present version of the executive summary in the ManOEUVRE project serves a dual purpose: it summarises the modelling activities in WP3 (i.e. Deliverable 3.1) and compiles datasets, models, and results in IAMC format as part of Milestone 3.2.

Iberian Region:

Case study 1: Feasibility assessment of green H₂ and thermal energy storage in Spain.

Case study 9: Power market modelling of Spain and Portugal

Nordic Region:

Case study 2A: Modelling Norwegian and Swedish energy export to facilitate the European low-carbon transition.

Case study 2B: Stochastic modelling of the Nordic power system.

Central Europe:

Case study 3: Global competitiveness and the energy demand of the energy-intensive industry

Case study 4: The role of growing demand in refinancing renewables.

Case study 5: Soft-linking BENOPTex and GENeSYS-MOD (mainly Germany)

Case study 8: Green transition in France

Mediterranean Region:

Case study 6: Integrating electricity and gas network supported by energy storage and power conversion processes

Case study 7: Greece as a renewable energy hub

Case study 1: Feasibility assessment of green H₂ and thermal energy storage in Spain

Case Study 1 explores Spain’s energy potential across three key dimensions with the aim of contributing to Europe’s energy self-sufficiency. First, it assesses **whether Spain can ensure a sufficient supply of renewable resources**, particularly solar and wind energy, to produce large volumes of green hydrogen and become a net exporter to Europe. **Second, it analyses the role of Spain’s current thermal storage capacity**, 6.7 GWh in its concentrated solar thermal power plant fleet, with plans to expand to 60 GWh by 2030, as a long-term energy storage solution. **Third, it investigates**



the potential of using heat from concentrated solar thermal energy to decarbonise the industrial sector, while considering current limitations such as high investment costs and low achievable solar fractions. All these assessments are carried out using the *TIMES-Sinergia* model to identify cost-efficient solutions for the production, storage, and export of renewable energy.

1.1. Accomplished Tasks

Task 1.1 – Improvement of Technology Modelling in the TIMES-Sinergia Framework. This task has focused on enhancing the modelling of technologies within the TIMES-Sinergia model via a thorough review of industrial sector demands for heat and hydrogen, updating the model accordingly, and introducing and characterising new technologies that were previously not included, in order to realistically and accurately represent the Spanish energy system. For the solar heat and thermal storage component, the company SOLATOM provided valuable data and technical insights to support the modelling of solar thermal technologies and heat storage

Task 1.2 – Adaptation of the ManOEUVRE Project Input Data to the TIMES-Sinergia Model. This task has entailed adapting the input data from the ManOEUVRE project to the structure and requirements of the TIMES-Sinergia model. We conducted an in-depth review and developed a methodology to manage and integrate the data provided by WP2, both in IAMC format and in its native form, the last one being more suitable for integration into TIMES. An Excel-based script was developed to map the technologies and facilitate the adaptation of the dataset to the TIMES-Sinergia framework.

Task 1.3 – Analysis of GENESYS-MOD Results and Comparison with the Spanish NECP. In this task, we analysed the output of the GENESYS-MOD model and compared it with the objectives and projections outlined in Spain's National Energy and Climate Plan (NECP). The goal was to assess how well the modelled pathways align with national targets for emissions reduction, renewable energy deployment, and sectoral transformation. Insights from this comparison were used to refine input data and adjust modelling assumptions, particularly in key sectors such as industry, transport, and power generation. This feedback loop has improved consistency with policy frameworks and increased the reliability of subsequent scenario analyses.

Task 1.4 – Scenario Development. In this task, we designed and created a set of energy transition scenarios within the TIMES-Sinergia model using the latest version of the input data and GENESYS-MOD results provided by WP2 (version 1.3.0). The four ManOEUVRE scenarios were created: GoRes, NECP Essentials, REPower++ and TrinityEU, reaching the project objectives. These scenarios reflect different pathways for the Spanish energy system, based on varying assumptions related to technology deployment, policy frameworks, renewable resource availability, and investment costs. They are aligned with the overarching goals of the ManOEUVRE project, exploring Spain's potential role in contributing to a decarbonised and energy-independent Europe.

Task 1.5 – Scenario Analysis. This task focused on analysing the scenarios developed in Task 1.4, with an emphasis on evaluating the techno-economic feasibility and system-wide impacts of various decarbonisation strategies, particularly those involving green hydrogen production, thermal energy storage, and industrial sector decarbonisation. The analysis identified key trade-offs, synergies, and policy implications, offering insights into the most effective pathways for Spain's energy transition.

Task 1.6 – Comparison with GENESYS-MOD Results. Finally, in the last task of CS1 in WP3, we conducted a comparative analysis between the results generated by the TIMES-Sinergia model and those obtained from the GENESYS-MOD model. The comparison focused on key indicators such as electricity generation and renewable energy deployment, hydrogen production and exports, storage



capacity utilisation, and emissions reduction. The goal was to identify consistencies and divergences between the two modelling approaches and to improve the robustness and credibility of the overall findings through cross-model validation.

1.2. Planned impact

Spain has the potential to play a strategic role in the future European energy system, not only as a leader in renewable electricity production but also as a key exporter of green hydrogen and provider of long-duration thermal storage solutions. With abundant solar and wind resources, as well as a growing fleet of concentrated solar thermal plants with storage capabilities, Spain could become a central hub for clean energy generation and cross-border energy support. However, realising this potential requires a deep understanding of national dynamics, such as industrial energy demand, infrastructure limitations, storage capacity, and technology deployment strategies, that are often oversimplified in broader European energy models.

This case study aims to deliver a more realistic and granular representation of the Spanish energy system under multiple transition scenarios, considering detailed modelling of the industrial sector, hydrogen production, and thermal energy storage. By combining the strengths of the TIMES-Sinergia and GENeSYS-MOD models and aligning the outputs with Spain's NECP, this CS helps identify robust and cost-effective pathways toward decarbonisation.

The results of this research will be highly valuable to stakeholders and decision makers involved in the development of national strategic plans, including NECPs, long-term energy strategies, and sector-specific roadmaps. The insights generated will support evidence-based policy design, inform investment priorities in infrastructure and innovation, and contribute to a more coordinated and resilient European energy transition. Furthermore, the case study will highlight the importance of Spain's role in the regional energy landscape, particularly in enabling energy independence and climate neutrality goals at the European level.

1.3. Implementation

1.3.1. Challenges

One of the main challenges in this project arises from the structural differences between the GENeSYS-MOD and TIMES-Sinergia models, which make direct data exchange unfeasible. As a result, input and output data must undergo a thorough aggregation or disaggregation process to match the format and resolution required by each model. This issue is particularly pronounced in the industrial sector, where TIMES-Sinergia provides a much more detailed and technology-specific representation compared to GENeSYS-MOD.

In addition, the complexity and inherent assumptions of both models mean that not all parameters can be fully harmonised. This may lead to discrepancies in results and requires careful interpretation when comparing outcomes across scenarios. Last version of the input dataset, version 1.3.0, has been used to run the Spanish model, and the last version of GENeSYS-MOD result, version 1.3.0, have been used both as input and for scenario comparison.

1.3.2. Mitigation Measures

Efforts have been made to align the most influential parameters, such as technology costs, fuel prices, and emissions factors, to ensure a meaningful and consistent comparison. Another layer of complexity is added by differences in temporal resolution, which must be addressed through a consistent



mapping methodology. A demand adjustment was made to reflect the different narratives of the scenarios, since TIMES-Sinergia has very detailed demand curves, and the input data had low resolution in that respect. Boundary conditions regarding international electricity and hydrogen exchanges have also been incorporated, taking advantage of the higher spatial resolution of the European model.

Ultimately, the aforementioned challenges highlight the importance of developing robust methodologies for cross-model integration and validation to strengthen the reliability of the project's findings. Therefore, to guarantee consistency, an Excel script was used to do the mapping between TIMES-Sinergia and ManOEUVRE input data to build the four ManOEUVRE scenarios: GoRes, NECP Essentials, RePower++ and TrinityEU.

1.4. Results

1.4.1. Outcomes

In this section we present the results of the four energy transition scenarios developed using the TIMES-Sinergia model compared with the results generated by the GENeSYS-MOD model for Spain and some key insights in the research questions of this case study: whether Spain can ensure a sufficient supply of renewable resources to produce large volumes of green hydrogen and become a net exporter to Europe, and the potential of using heat from concentrated solar thermal energy as thermal storage to decarbonise the industrial sector.

Electricity production

The evolution of the Spanish power sector composition from 2025 to 2050 across the four energy transition scenarios is illustrated in Figure 1.1, comparing the outputs of TIMES-SINERGIA, GENeSYS-MOD and the Spanish NECP (PNIEC). Overall, the two models display a consistent picture regarding the long-term role of renewable energy technologies and the gradual phase-out of fossil and nuclear-based generation. This convergence indicates a robust agreement on the main structural trends of the Spanish power system transformation.

In addition, both models are in broad agreement regarding the total amount of electricity generated over the period, showing similar trajectories of increasing electricity demand and supply up to 2050. This consistency in overall electricity production levels further supports the robustness of the modelling results, indicating that the main differences arise not from the scale of power generation, but rather from the technology mix chosen to meet this growing demand.

Both models also agree on the overall balance between variable renewable generation (i.e. wind and PV) and dispatchable capacity, ensuring system reliability in the long-term. However, their technological preferences within the dispatchable portfolio diverge: GENeSYS-MOD tends to prioritise biomass and hydropower, whereas TIMES-SINERGIA assigns a more prominent role to concentrated solar power (CSP) complemented with hydropower.

These differences highlight the importance of cross-model comparisons, as they reveal the uncertainties associated not only with the scale of variable renewable deployment but also with the choice of complementary dispatchable technologies under alternative transition pathways.

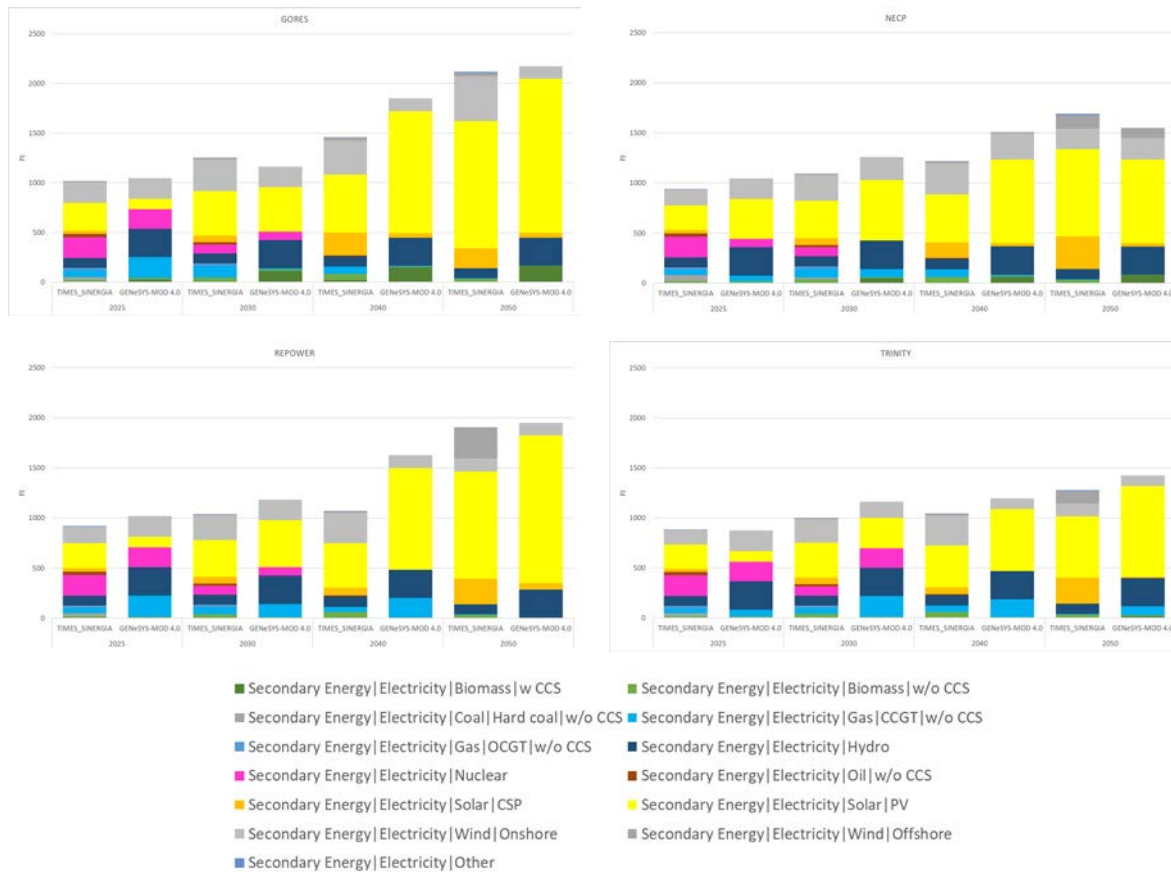


Figure 1.1. Evolution of the Spanish power sector composition from 2025 to 2050.

Hydrogen production and export potential

Figure 1.2 shows the balance of hydrogen production and consumption in Spain from 2040 to 2050, since it is not significant before, under the four Man0EUvRE transition scenarios in TIMES-Sinergia. In all scenarios, hydrogen demand rises steadily, primarily driven by industry and transport, with additional contributions for power generation, residential uses, and refineries. On the supply side, electrolysis is the dominant production technology, supported by smaller shares from steam methane reforming (SMR) and solar SMR. Across all scenarios, hydrogen increasingly provides sectoral flexibility and supports decarbonisation, confirming its central role in Spain's energy transition.

There is a surplus that is destined for export, reaching 204 PJ in the most favourable scenario (GORES) and 31 PJ in the less favourable scenarios (TRINITY). This indicates that domestic supply systematically exceeds internal demand, and positions Spain as a potential exporter of green hydrogen. The convergence across scenarios highlights the robustness of this result: regardless of the specific policy or market pathway, Spain's abundant renewable resources provide favourable conditions for competitive large-scale hydrogen production through electrolysis.

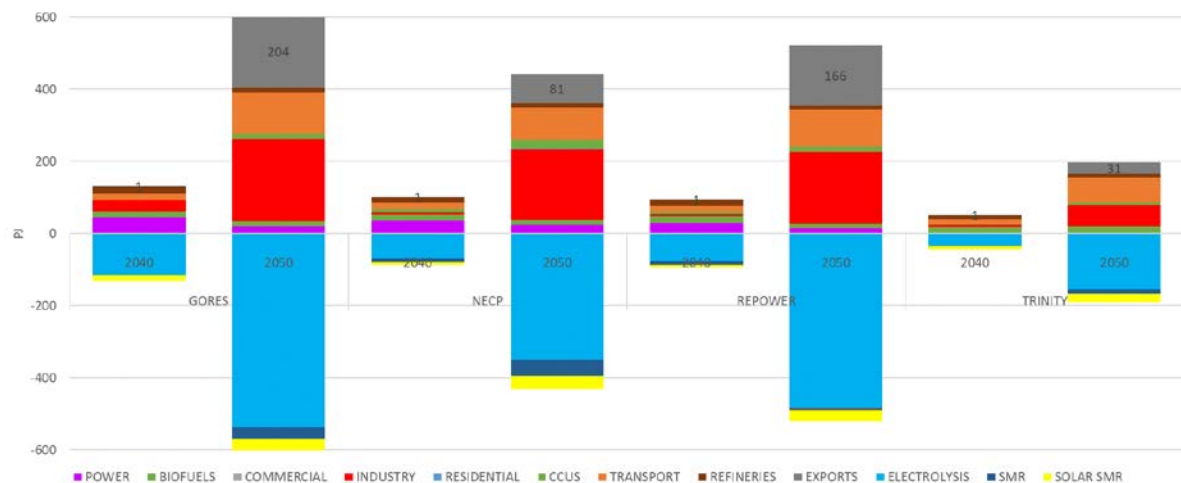


Figure 1.2. Hydrogen production and consumption in Spain (2030–2050) across the four TIMES-SINERGIA transition scenarios. Bars above zero show end-use demand by sector; bars below zero show domestic production by technology.

Based on Figure 1.3, results from TIMES-SINERGIA and GENeSYS-MOD differ in deployment speed with regards to H₂ production. Compared with GENeSYS-MOD v1.3, TIMES-SINERGIA reproduces the scenario ranking but diverges in the timing and scale of hydrogen deployment. GENeSYS-MOD projects substantially higher volumes in 2040, notably in NECP and TRINITY ($\approx 3\text{--}4$ times TIMES-SINERGIA), reflecting more target-driven pathways and lower adoption frictions. By 2050, trajectories converge: TIMES-SINERGIA almost reaches GENeSYS-MOD in GORES and REPOWER, while NECP and TRINITY remains lower. Particularly striking are the differences in the TRINITY stage, which have been discussed with WP2. Overall, Spain's hydrogen potential appears robust, while the pace of deployment can vary.

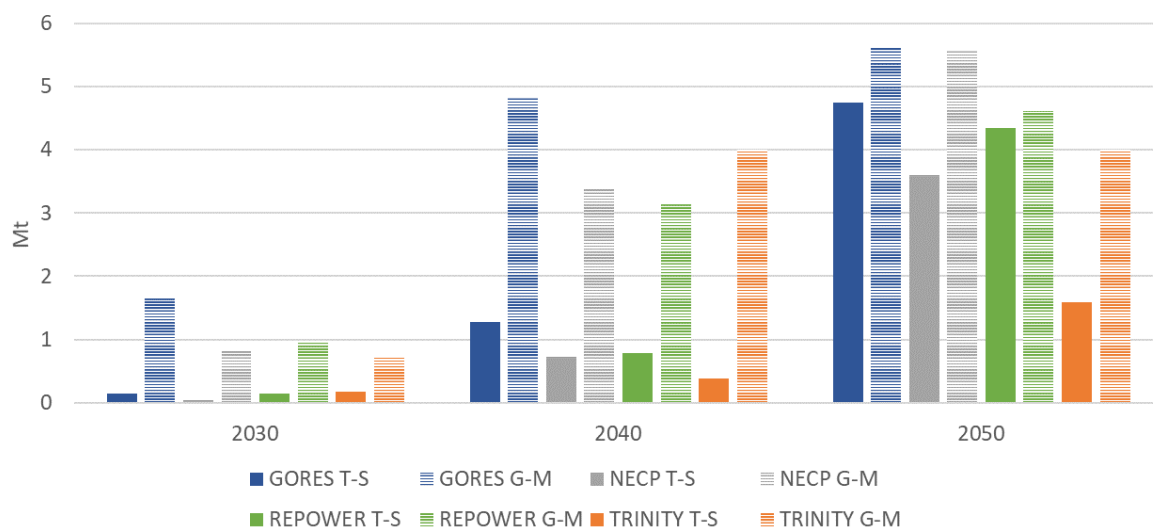


Figure 1.3. Domestic hydrogen production in Spain (2030–2050) by scenario and model. Solid bars show TIMES-SINERGIA results (GORES, NECP, REPOWER, TRINITY); striped bars show the corresponding GENeSYS-MOD v1.3 benchmarks (GoRES, NECP Essentials, REPowerEU++, TRINITY).

As shown in Figure 1.4, in terms of technology selection and in all scenarios, GENeSYS-MOD uses a broader technology mix (including SMR/ATR+CCS). In contrast, TIMES-SINERGIA concentrates supply in electrolysis tightly coupled to variable renewables.

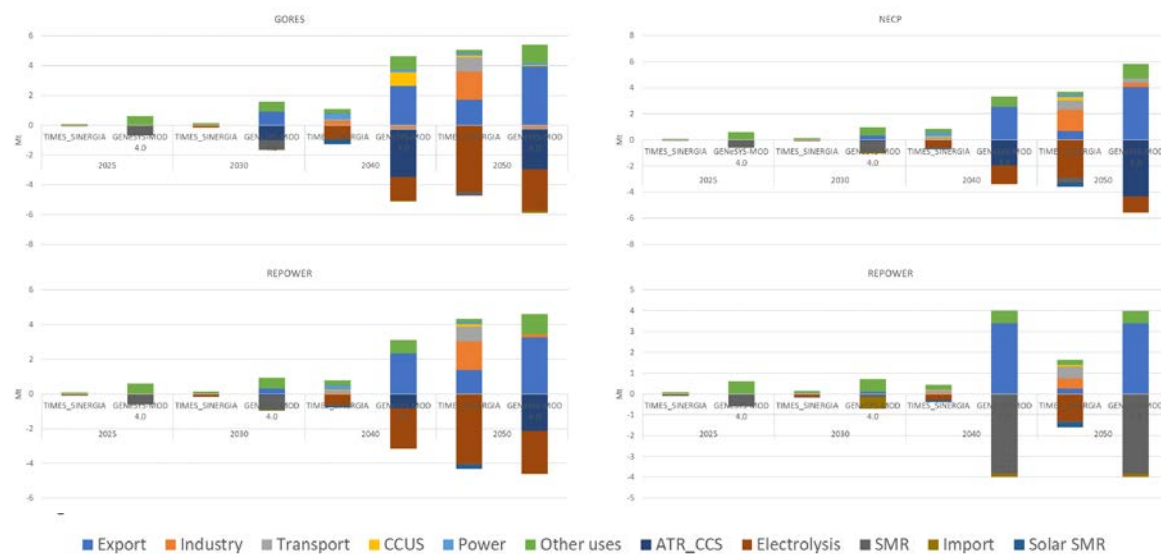


Figure 1.4. Hydrogen balance by technology (production, <0) and end uses (≥0), 2025–2050. Stacks below zero show production by technology (Electrolysis, SMR), while stacks above zero show uses (Exports, Power, CCUS, Other uses).

In scenario GORES, GENESYS-MOD shows a higher net balance already by 2040, supported by a mixed supply (electrolysis plus some ATR/CCS). TIMES-SINERGIA accelerates after 2040 and becomes similar by 2050, almost entirely electrolysis-led. Being more based on electrolysis, electrolyser capacity reaches 130 GW in TIMES-Sinergia vs ~32 GW in GENESYS-MOD by 2050 as shown in Figure 1.5.

The same pattern holds in scenario NECP with slightly lower ambition: GENESYS-MOD is ahead in 2040, but TIMES-SINERGIA reach closer, but still big differences by 2050, driven by electrolysis. Electrolyser capacity reaches 75 GW in TIMES-Sinergia vs 13 GW in GENESYS-MOD in 2050 as shown in Figure 1.5.

Same pattern holds in REPOWER scenario: again GENESYS-MOD ramps earlier (notable exports by 2040 with support from SMR/ATR-CCS), while TIMES-SINERGIA concentrates growth after 2040 and almost equalling by 2050 on an electrolysis-only pathway. Electrolyser capacities in 2050: 115 GW (TIMES-Sinergia) vs ~25 GW (GENESYS-MOD) as shown in Figure 1.5.

Under lower ambition, in TRINITY scenario, differences are much higher, in fact, in the difference is striking compared to TIMES-Sinergia. These results have been commented on with WP2. Electrolyser capacities in 2050: 28 GW (TIMES-Sinergia) vs 0 GW (GENESYS-MOD), as is all SMR/ATR-CCS hydrogen production, as shown in Figure 1.5.

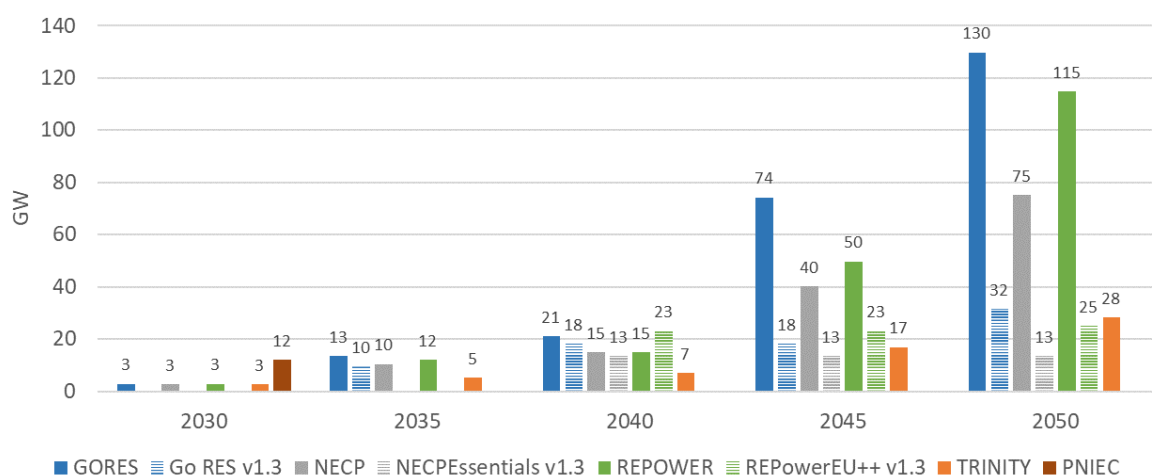


Figure 1.5. Electrolyser capacity in Spain (GW, installed), 2030–2050. Solid bars are TIMES-SINERGIA (GORES, NECP, REPOWER, TRINITY); hatched bars are the corresponding GENE SYS-MOD v1.3 benchmarks; the brown bar marks the PNIEC 2030 reference.

For Spain, ATR with CCS is not a strategic option: the country lacks domestic natural gas resources, and large-scale CO₂ capture, transport and storage is not a policy priority. By contrast, Spain's abundant renewable potential (wind and solar) makes electrolysis the natural cornerstone for low-cost, scalable hydrogen. An electrolysis-centric pathway also aligns better with power-system decarbonisation, enabling flexible absorption of variable renewables and reducing import dependence. The model comparison is therefore consistent with national strengths: TIMES-SINERGIA's electrolysis-heavy buildout reflects a pathway that is both technically coherent and strategically sound for Spain.

Potential of using solar heat to decarbonise the industrial sector

In collaboration with SOLATOM—manufacturer of Concentrated Solar Thermal (CST) heat and thermal energy storage (TES)—we assess the potential of medium-temperature solar heat (≈120–300 °C) in Spanish industry. We focus on pharma, construction, food, beverage & tobacco, and textile & leather, which exhibit the highest medium-temperature heat demand. The technology is represented with primary performance and cost data from SOLATOM. The solar field can either (i) deliver process heat directly or (ii) charge a TES unit for deferred use. The optimisation takes hourly industrial demand profiles and solar availability as inputs, allowing the model to decide when to produce or store heat to minimise system costs/emissions subject to operational constraints.

As shown in Figure 1.6, CST achieves modest but increasing penetration in the target sectors across all transition scenarios. Initial limited penetration reflects competition with dispatchable and non-variable options, such as coal and light fuel oil. As emission reduction targets become more stringent, solar heat increases its market share alongside the transformation of high-temperature heat (first from gas combined heat and power (CHP) systems and then from biomass CHP systems) into medium-temperature heat.

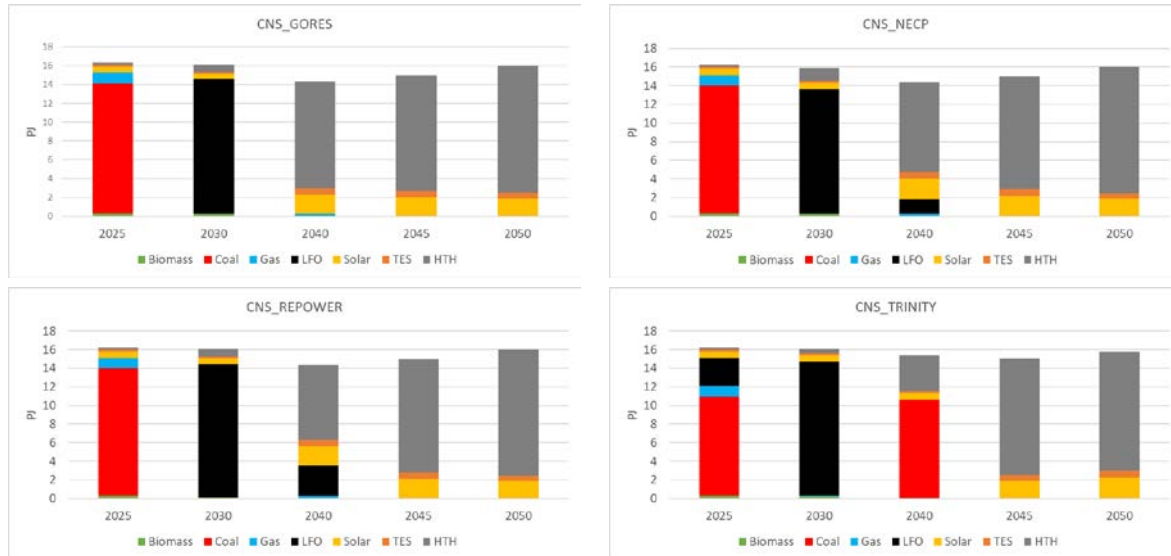


Figure 1.6. Penetration of CST with thermal storage in the construction sector across all the transition scenarios.

The role of the storage system is pivotal in the penetration of solar heat as it extends operating hours beyond sunset, smooths intraday variability, and reduces auxiliary fossil backup. Uptake is driven by (a) good coincidence between solar resources and daytime process loads, (b) the ability of TES to shift heat into late afternoon/evening hours.

Figure 1.7. illustrates the typical operating pattern of the system. As an example, we show the behaviour of the system in the construction sector in 2050 and in the GoRES scenario. Around midday (hours 10–14), the solar field reaches its production peak (yellow). Some part is directed to the TES unit (grey), which is mainly charged from late morning to early afternoon. As solar irradiance decreases towards the end of the day, the stored heat is progressively discharged (orange), allowing the system to continue supplying useful thermal energy during the late afternoon and evening hours, even after sunset.

The same operating pattern can be observed throughout the different seasons, although with variations in intensity. In winter, solar output peaks are lower and more concentrated around midday, limiting the amount of heat available for storage. By contrast, in summer the solar field produces higher and more sustained outputs, resulting in broader production plateaus that extend over several hours. During these periods, the thermal storage system plays a more active role: it is charged more frequently and discharged later in the day, enabling the system to shift solar heat production from the hours of maximum irradiance to the evening demand.

The consistent presence across scenarios indicates robustness to broader system assumptions. Priority use-cases are sites with (i) daytime-weighted loads, (ii) contiguous roof/ground area for collectors, (iii) tolerance for 120–300 °C heat integration, and (iv) space for TES tanks near points of use.

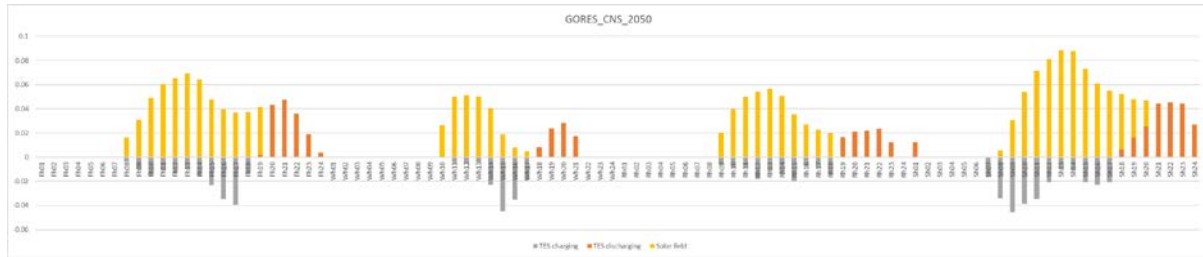


Figure 1.7. Typical operating pattern of the CST heat and TES systems.

1.4.2. NECPs

Electricity production in TIMES-SINERGIA aligns quite well with the NECP, with slightly lower shares on wind and PV and total electricity production of the system, as shown in Figure 1.1. In contrast, GENeSYS-MOD shows less electric production with a lower presence of PV at wind power.

Regarding hydrogen production, the Spanish NECP set an ambitious objective for electrolyser capacity (12 GW) in 2030, which TIMES-Sinergia achieves somewhat late, in 2035, similar to GENeSYS-MOD but only in GORES scenario as shown in figure 1.5. For Solar heat and thermal storage, the Spanish NECP doesn't specify any minimum capacities or other objectives.

1.4.3. Supplementary Data

To incorporate GENeSYS-MOD parameters into our model, as a first step, we constructed a dictionary establishing the correspondence between the technology names used in GENeSYS-MOD and those included in the TIMES-SINERGIA model. We developed four scenario files and included them in the model runs to generate results for the four ManOEUVRE scenarios. Each file contains input data from GENeSYS-MOD: Investment costs, Fixed O&M costs, Variable O&M costs, and Efficiencies.

GENeSYS-MOD emission results were also used as inputs and embedded in the scenario files. Three additional files were created to capture differences in energy-service demand across the ManOEUVRE scenarios by varying the GDP growth used to project the demands computed in TIMES-SINERGIA. NECP and REPOWER use the central GDP-growth case, while GORES and TRINITY use the high- and low-growth cases, respectively.

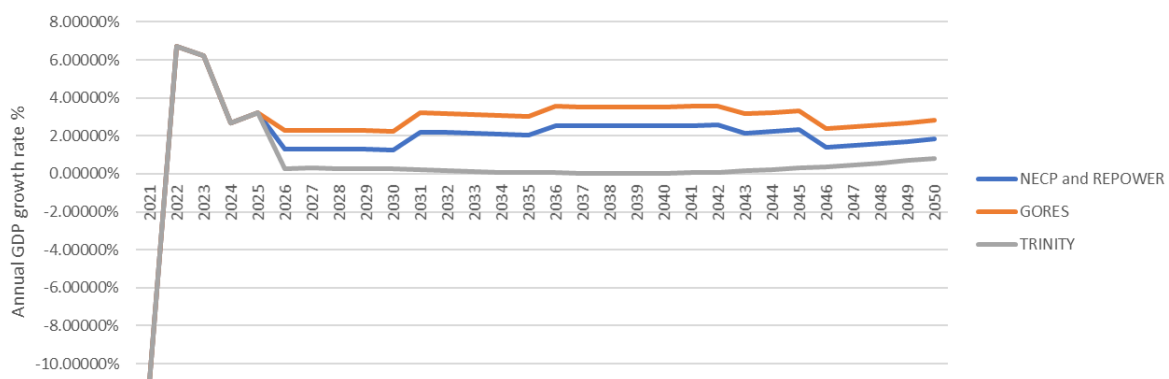


Figure 1.8. GDP growth evolution considered in the four MANOEUVRE scenarios.

The last version of GENeSYS-MOD results was used for scenario comparison and as input for TIMES-SINERGIA model. You can find them in: <https://github.com/carlosmantillaciemat/ManOEUVRE.git>



Case study 2: Modelling the ability for Norway and Sweden to support European low-carbon transition

This case study investigates the potential of the Scandinavian energy system to contribute to the European energy transition. The analysis is conducted in parallel with two models: TIMES-NOSE (**Part A**) and FanSi (**Part B**).

First (**Part A**), the study evaluates the long-term system-wide capability, encompassing various energy carriers and sectors, with the comprehensive *TIMES-NOSE* model. The findings highlight that Norway and Sweden can contribute to the European energy transition in very different ways, either as a provider primarily of electricity (as today), or as a provider of green hydrogen (from Norway) and of green industrial products (from Sweden primarily).

Second (**Part B**), focus is on the power sector, with particular emphasis on hydropower as a stochastic energy storage solution supporting VRE. The findings offer new insights into the challenges of transitioning from broad, cross-sectoral models to more detailed, sector-specific analyses, and highlight how these approaches can complement and reinforce one another.

Part A: Analysing Norwegian and Swedish energy export to facilitate the European low-carbon transition

This case study examines how Norway and Sweden can decarbonise their closely connected energy systems while also contributing to the European energy transition, by providing low-carbon energy commodities such as electricity and hydrogen, and energy-intensive green industrial products, such as iron, steel and aluminium.

The analysis focuses both on the transition of existing domestic industry and on announced plans for new energy-intensive industrial developments in the Nordic region, such as iron and steel production, battery factories, synthetic fuel production, and data centres. Using a model-based approach, the study explores different transition pathways that are driven by both national industry policy and international context.

The results show that interaction with Europe depends on external factors, described by the ManOEUVRE scenarios, and on national industrial activity. Outcomes range from high domestic electrification and hydrogen use to largescale energy exports that support European decarbonisation. The case study highlights the trade-off between using electricity domestically, for hydrogen and green industries, and exporting electricity directly to Europe. For example, offshore wind electricity can either be exported to support the REPowerEU targets, or be used domestically to produce hydrogen and low-carbon industrial products that replace more carbon-intensive production elsewhere.

2A.1. Accomplished Tasks

Task 2A.1 – Industry scenarios: In this task, a set of industry scenarios was developed to outline *potential* pathways for the green transition of energy-intensive industries in Norway and Sweden toward 2050. These scenarios capture uncertainties related to immature technologies, policy and regulatory frameworks, international competitiveness, and the availability of energy resources. They lay the foundation for the scenario analysis, which provides deeper insights into different decarbonisation pathways for industry and their potential implications for the wider energy system. The industry scenarios are documented in a separate report, “Industry pathways for Norway and Sweden”, that presents current energy use and greenhouse gas emissions from industry,

decarbonisation strategies, plans for new industries, and the storylines and rationales for future developments.

Task 2A.2 – Model extensions: In this task, the required model extensions are implemented to capture the necessary level of detail in the Norwegian and Swedish energy systems, with a particular focus on the industry sector and the modelling of hydrogen.

Task 2A.3 – Model coupling and parameterisation: To ensure consistency with the EU EnVis2060 scenarios, this task focuses on aligning TIMES-NOSE with scenario data from WP2. This includes harmonising key input parameters, such as techno-economic assumptions for renewable electricity (onshore and offshore wind, rooftop and utility-scale solar PV), and hydrogen production. Assumptions about cross-border energy trade are also aligned with the EU EnVis-2060 storylines.

Task 2A.4 – Scenario analysis: This task defines the scenarios that are modelled and analysed in the case study. Based on industry scenarios from Task 2A.1, two possible industry developments in Norway and Sweden are defined:

- Lo – low industry demand projections towards 2050, and
- Hi – high industry demand projections towards 2050.

The model scenarios are also aligned with two EU EnVis-2060 scenarios, GoRES and Trinity, which represent different future developments of the European energy landscape regarding geopolitical instability, social dynamics, and technology innovation and costs. Combining the low and high domestic industry demand assumptions with the EU scenarios results in four scenarios that form the basis for the analysis:

		EU EnVis scenario	
		Trinity	GoRES
Domestic industrial energy demand	Low	LoTri Low domestic industrial energy demand under the Trinity scenario	LoGo Low domestic industrial energy demand under the GoRES scenario
	High	HiTri High domestic industrial energy demand under the Trinity scenario	HiGo High domestic industrial energy demand under the GoRES scenario

Figure 2A.1. Four scenarios from the combinations of two energy demand values and two EU EnVis scenarios.

The scenarios do not include binding climate targets, such as a requirement to reach net-zero CO₂ emissions by a specific year. Instead, the scenarios apply CO₂ prices to fossil-based emissions, reflecting current European climate policy. Two alternative CO₂ price paths are used, both assuming gradually increasing prices over time.

Task 2A.5 – Comparison with GENeSYS-MOD results: The results from the TIMES-NOSE model are compared with results from the GENeSYS-MOD model for Norway and Sweden. The comparison focused on identifying similarities and differences between the models and on providing feedback to improve the GENeSYS-MOD representation.



2A.2. Planned impact

Norway and Sweden play an important role in supplying clean and reliable electricity to Europe. With large hydropower resources and interconnection to the European power market, the two countries act as a green battery, exporting surplus electricity to help balance the European power system. In 2024, Norway's net-export was 18 TWh¹ and Sweden's net-export was 33 TWh², or 12% and 19% of the total domestic electricity generation, respectively.

At the same time, both countries have ambitious plans to decarbonise existing industries, mainly through electrification, and to develop new energy-intensive industries. This creates uncertainty about future energy demand, supply, and infrastructure needs. European-wide energy models often capture overall trends, but they do not fully represent national conditions such as infrastructure, industrial transition plans, flexibility options, or national policies.

Hence, this case study improves the understanding of how Norway and Sweden can contribute to the European energy transition by supplying energy carriers such as electricity, hydrogen, and bio and synthetic fuels, as well as energy-intensive green industrial products, under different transition pathways.

The results provide useful insights for stakeholders and decisionmakers on how future energy systems in Norway and Sweden may develop. By considering different industry pathways, renewable resource availability, and technology costs, the analysis supports informed decisions on energy policy, infrastructure investment, and resource use. The study also highlights the importance of cross-border cooperation between Norway, Sweden, and the rest of Europe.

2A.3. Implementation

2A.3.1. Challenges

Due to structural differences between GENeSYS-MOD and TIMES-NOSE, the data could not be fully harmonised and exchanged one-to-one but needed some further aggregation or disaggregation. This was particularly relevant for the industry sector, where TIMES-NOSE offers a significantly more detailed representation of the Nordic system. Hence, some caution is due when comparing results from the two models.

2A.3.2. Mitigation Measures

There has been an active dialogue between TU-Berlin and the researchers involved in case study 2, through webinars and e-mail correspondence, to facilitate a better understanding of the differences between the respective models and their outputs. Through these discussions, the teams concluded that case-specific knowledge, particularly concerning energy system characteristics and anticipated developments in Norway and Sweden, should guide key modelling assumptions, especially regarding future industrial demand growth scenarios and renewable resource potentials. Meanwhile, assumptions on technology learning and cost projections for key technologies were instead based on GENeSYS-MOD results.

¹ IEA, <https://www.iea.org/countries/norway/electricity> (accessed on 28 March 2026)

² IEA, <https://www.iea.org/countries/sweden/electricity> (accessed on 28 March 2026)



2A.4. Results

2A.4.1. Outcomes

This section presents results from the TIMES-NOSE model from four scenarios that combine two different levels (low and high) of industrial demand growth in Norway and Sweden with two EU EnVis-2060 scenarios, GoRES and Trinity.

The results address the main questions of the case study: how much energy (electricity and/or hydrogen) Norway and Sweden can export to Europe, how different levels of domestic industrial growth affect this potential, and how technology development affects the outcomes.

Note that the demand in the transport and building sectors is assumed to grow in line with the general socio-economic development, and this demand is not varied across the scenarios.

Highlights

Norway and Sweden have significant potential to contribute to the European energy transition beyond their national borders. This potential is supported by cost-competitive renewable resources, high integration with the European power market, and energy-intensive industrial structures and growth plans.

- Across model scenarios, Norway and Sweden play different roles in the European energy, shaped by a combination of domestic industrial developments and European and international dynamics.
- In a low-demand scenario, with a limited domestic industrial growth, Norway and Sweden remain significant providers of electricity (and potentially hydrogen) to the European energy system.
- In a high-demand scenario, Norway's export is reduced, but the country remains a net provider of energy commodities (primarily hydrogen) to Europe.
- In a high-demand scenario, Sweden's industry sectors grow considerably, adding to domestic demand for electricity and green hydrogen, whereby Sweden becomes a net-importer of energy commodities to support the production of energy-intensive green industry products (steel, batteries, synthetic fuels, etc.) available for export.
- Only small variations in electricity demand from buildings and transportation are found; hence, future electricity demand in Norway and Sweden depends largely on the scale of industrial activity and the pace of industrial decarbonisation. Total electricity demand in 2050 across the two countries ranges from 360 to 570 TWh.
- Across all model scenarios, hydrogen is exclusively produced via electrolysis using the low-carbon electricity of the Nordic system. Under favourable conditions, Norway emerges as a major supplier of green hydrogen to northern continental Europe.
- Electrification and green hydrogen reduce industrial CO₂ emissions in Sweden and Norway, but neither model scenario achieves net-zero by mid-century, underlining the hard-to-abate nature of some industrial sectors, and the need for additional targeted mitigation measures besides a general CO₂ price.

Electricity demand, production, and trade

The evolution of electricity demand and generation in Norway and Sweden, and trade with neighbouring countries, differs considerably across the four scenarios. Figure 2A.2 demonstrates

electricity demand across the different scenarios in 2025 and 2050, broken down by sector. The figure shows that total electricity demand can be expected to grow regardless of the scenario. However, for both countries, the differences between the most conservative (LoTri) and the most progressive (HiGo) scenarios clearly illustrate the very large ‘space’ of potential future outcomes for the Nordic power system, under different industry development pathways.

In Norway, the increase from 2025 to 2050 ranges from 23 to 136 TWh (16–97%) across the scenarios. The variations are mainly due to differences in industrial electrification and electricity use for hydrogen production. In the low-demand cases (LoTri and LoGo), industrial electricity demand remains much lower than in the high-demand cases (almost doubles in HiTri and HiGo). Meanwhile, in the GoRES scenarios, hydrogen-related electricity demand is much greater, driven by the cost projections for hydrogen technologies and the more favourable export conditions.

In Sweden, the growth in electricity demand is even larger, ranging from 71 to 165 TWh (57–133%) by 2050. Some of the demand increase comes from transport sector electrification, and from direct use of electricity in industry, yet compared with Norway, direct industrial electricity use varies less between the scenarios. Instead, the single biggest driver of demand growth is the need for electrolysis-based hydrogen to support decarbonisation of the iron and steel industry, including the ongoing build-up of an all-new green steel factory in northern Sweden, and for synthetic e-fuel production.

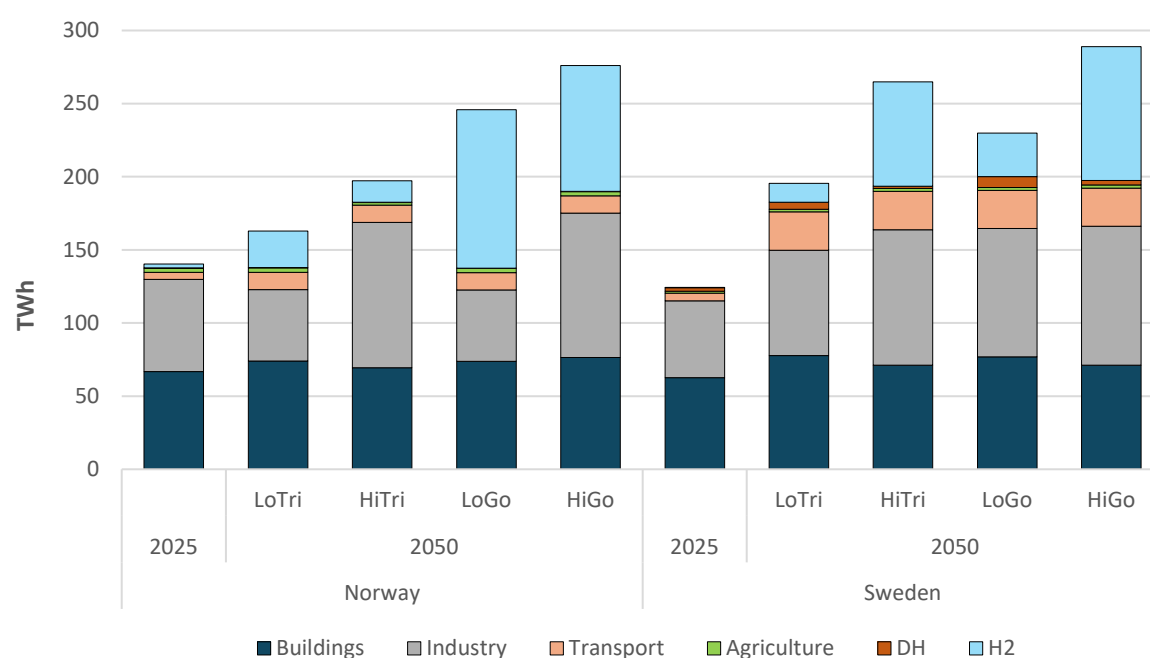


Figure 2A.2. Electricity demand (TWh) in Norway and Sweden across sectors and scenarios in 2025 and 2050. DH = District Heating. H2 = Hydrogen.

Growth in electricity demand drives growth in domestic electricity production (and in trade). Figure 2A.3 depicts the resulting electricity production mix by each country, in the four scenarios, in 2025 and 2050. In Norway, hydropower continues to form the backbone of the electricity system across all scenarios³, with varying levels of additional variable renewable energy layered on top. The changes in the Norwegian generation mix mainly entail a build-out of wind power. Onshore wind development is impacted by the cost variations between Trinity and GoRES, as well as the energy demand levels. Neither of the low-demand scenarios reaches the assumed full expansion potential; production ranges

³ It is also shown in CS8 (see Figure 8.4 and Figure 8.9).

from 19 TWh to 39 TWh, with the southern parts of Norway as the most favourable region. Offshore wind expands very modestly in the Trinity scenarios, reaching between 7 and 15 TWh by 2050, but grows substantially under GoRES, where more optimistic underlying assumptions for technology learning and cost reduction lead to deployment of 58 to 65 TWh by 2050. With low domestic demand (LoGo), much of the added electricity instead goes into producing hydrogen for export.

Wind power is also the least-cost option in Sweden. The potential for onshore wind power is set at 70–100 TWh (depending on the scenario), while offshore wind potential is limited to 50 TWh. These assumptions reflect current trends, including slow permitting processes for new onshore wind projects and the Government’s decision in November 2024 to halt more than 125 TWh of planned offshore wind capacity in southern Sweden. In the cost-optimised results, the model endogenously utilises the full onshore wind potential, indicating that it is among the most cost-efficient options for meeting future electricity demand. Hydropower generation remains at around 70 TWh, as no additional investments are allowed in the model, while utility-scale PV expands significantly in the model results, reaching up to around 50 TWh of generation by 2050. Note that the latter is highly sensitive to assumed wind power deployment limitations. Existing nuclear power plants (7.1 GW) are assumed to undergo lifetime extension without additional cost. Installed capacity gradually declines over time, with 4.84 GW remaining in 2041, 3.67 GW in 2043, and 2.48 GW in 2045. From 2050 onwards, 1.45 GW remains in operation for the rest of the model horizon. No new investments in nuclear power occur under the assumed investment cost of 6000 EUR/kW (based on IAEA reference values), reflecting the strong cost-efficient expansion of renewable energy in Sweden. To further assess the potential role of nuclear power, future analyses should also consider lifetime extension options for the existing nuclear fleet beyond a 60-year operating lifetime.

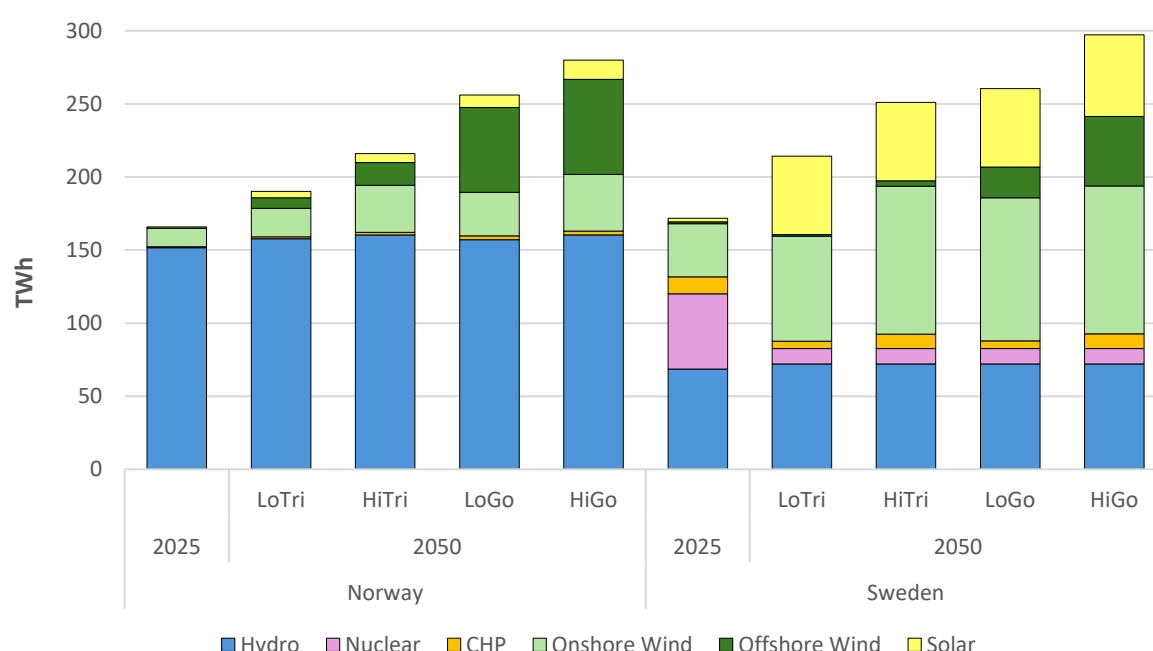


Figure 2A.3. Electricity production mix (TWh) in Norway and Sweden in 2025 and 2050 across the four scenarios. CHP = Combined Heat and Power.

Norway and Sweden are currently net exporters of low-carbon electricity to Europe, but with anticipated domestic demand growth, particularly from industry, the role of the Nordics may change. Figure 2A.4 illustrates that large electricity exports from Norway and Sweden persist in 2030 across all scenarios, and in LoTri (with low domestic demand), net exports of 21 TWh from Norway and 15 TWh

from Sweden are also found in 2050. However, with high domestic demand absorbing a greater share of the generation, the electricity trade changes significantly. In HiTri and HiGo scenarios, by 2050, Sweden instead becomes a net importer of more than 20 and 4 TWh, respectively. Norway drastically reduces its exports of electricity in all scenarios by 2050, even importing 2 TWh in HiGo. Notably, in GoRES scenarios, renewable electricity generation is expanded considerably in Norway, but a large share of this electricity is used for producing hydrogen (see Figure 2A.2) for export to Europe (instead of exporting electricity).

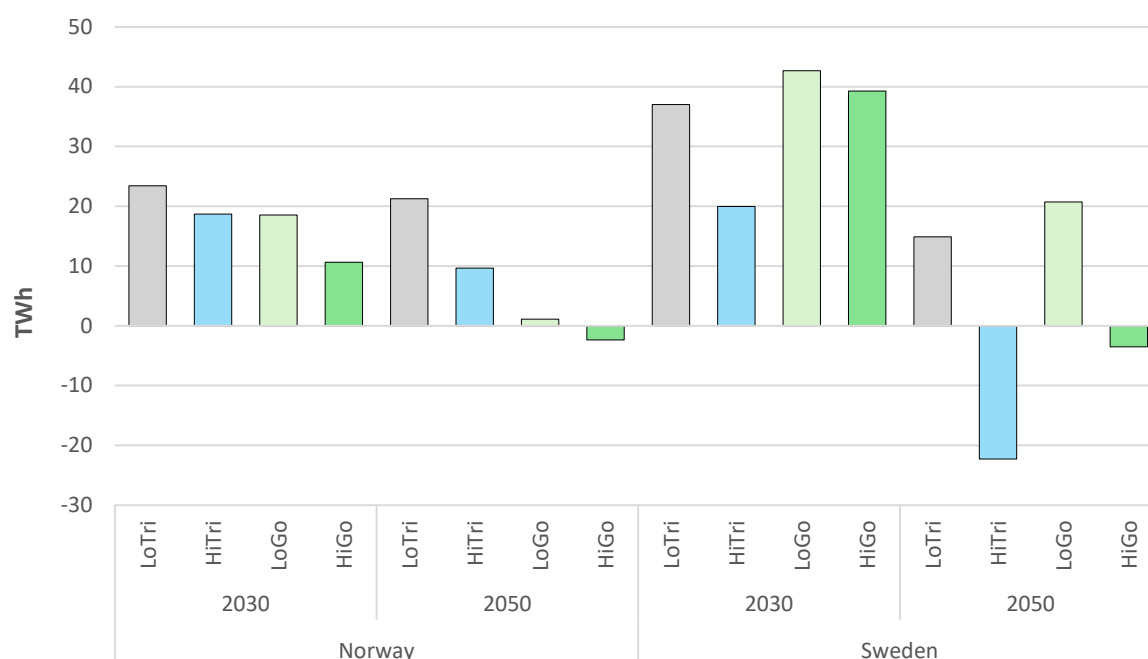


Figure 2A.4. Net electricity trade (TWh) to/from Norway and Sweden, by scenario, in 2030 and 2050.

Hydrogen demand, production, and trade

In all scenarios, and in both countries, hydrogen-use grows considerably, but it remains a niche product used in a limited number of applications, rather than being widely used across the economy (see Figure 2A.5). This points to a more targeted role for hydrogen in applications, where direct electrification is not an option.

In Norway, total hydrogen use varies between 12 and 24 TWh in 2050, with the greatest demand coming from the industry in the Trinity scenarios and from e-methanol production in the GoRES scenarios. In Sweden, total hydrogen demand varies between 25 and 88 TWh in 2050. In Low scenarios, the greatest demand for hydrogen comes from producing e-fuels, mainly e-methanol that replaces fossil fuels in shipping, and synthetic aviation fuels (e-SAF). In the High scenarios, which include a more progressive demand growth in industry, this sector takes over as the main user of hydrogen in Sweden (more than 50 TWh in 2050).

In addition, the fuel refinery sector remains a stable hydrogen user in Sweden, while it is not visible as a major category in Norway. Direct use of hydrogen in buildings and transport remains negligible in all cases.

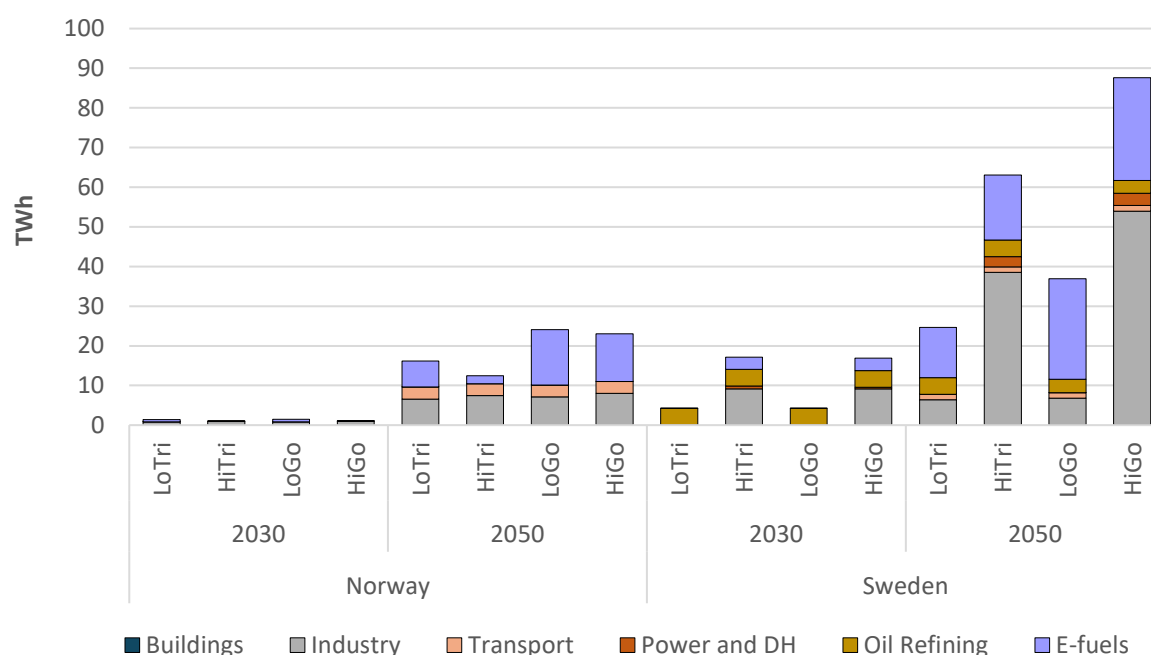


Figure 2A.5. Domestic hydrogen demand (TWh) in Norway and Sweden, in each scenario, in 2030 and 2050.

Across all scenarios, hydrogen is produced exclusively by electrolyzers. As can be seen in Figure 2A.6, hydrogen production varies considerably across scenarios: between 10 and 76 TWh in Norway and between 8 and 64 TWh in Sweden in 2050. Comparing these outcomes to the hydrogen demand shown in Figure 2A.5, it is obvious that production is not only driven by domestic demand.

In Norway, the highest hydrogen volume occurs in the LoGo scenario; this is the result of lower electricity prices due to lower demand combined with quicker cost reductions (of hydrogen production technologies) in GoRES compared to Trinity. Most of this hydrogen is traded from Norway, with 52 TWh being exported in 2050, mainly to the Netherlands (67%) and Germany (27%). In Sweden, the highest hydrogen volume occurs in the HiGo scenario, driven by domestic demand for hydrogen in the iron and steel industry and announced plans to produce synthetic e-fuels for shipping (e-methanol) and aviation (e-SAF). This underscores a key difference between the two countries; under the right conditions, Norway has good opportunities for producing large volumes of hydrogen, but as domestic demand is not that large, the country becomes highly export-oriented, supplying large volumes of hydrogen to Europe. Meanwhile, Sweden's hydrogen scale-up is primarily linked with the domestic industrial transition, enabling the production of green industrial products and e-fuels, some of which will be exported to Europe (instead of exporting hydrogen or electricity).

Another insight is the role of hydrogen production as a flexible electricity-user. By 2050, both flexible and inflexible electrolyzers will contribute substantially, especially in the most expansive hydrogen cases. However, the relatively large share of flexible electrolyzers (combined with hydrogen storage) suggests that the value of hydrogen is not only in its direct use as an energy carrier or industrial feedstock, but also in its ability to make good use of occasional low-cost electricity in power systems with large shares of variable renewables, such as wind and solar.

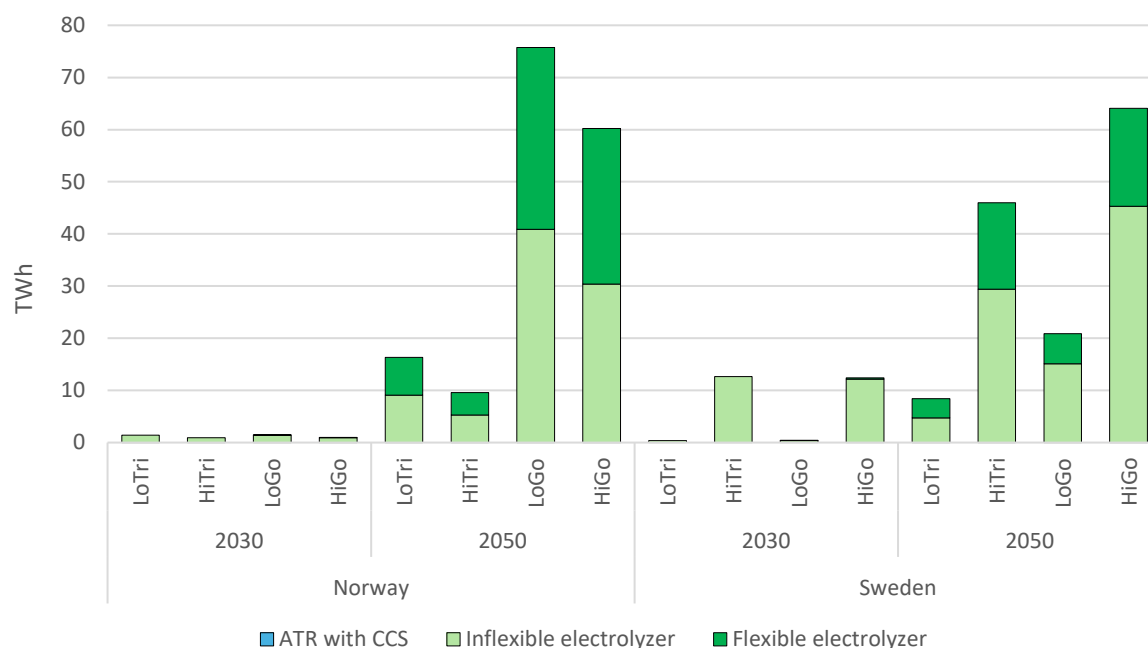


Figure 2A.6. Hydrogen production (TWh) in Norway and Sweden across scenarios in 2030 and 2050.

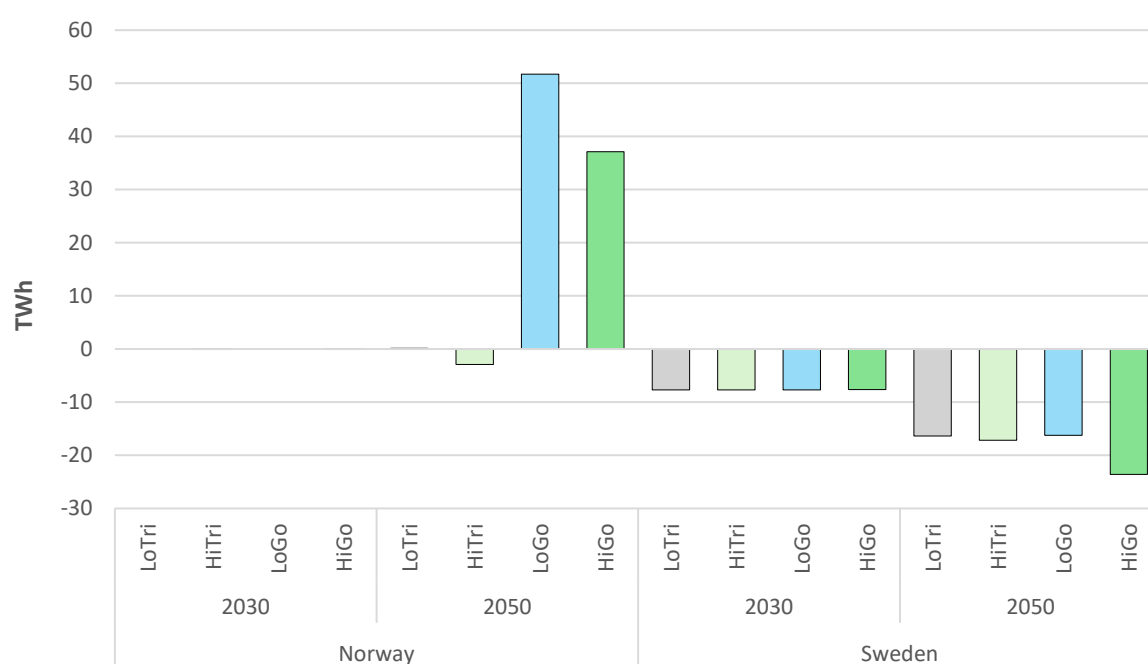


Figure 2A.7. Hydrogen trade (TWh) to/from Norway and Sweden across scenarios, in 2030 and 2050.

The net-trade of hydrogen is shown in Figure 2A.7. The trade patterns further underline the main difference between Norway and Sweden. Norway emerges as a major exporter (mainly to the Netherlands and Germany) in the GoRES scenarios, especially when domestic industrial demand is lower (LoGo). In the Trinity scenarios (with higher costs of hydrogen technologies), Norwegian hydrogen production is significantly lower, and it is almost exclusively used domestically in industry and e-fuels production. Sweden, on the other hand, remains a significant net importer of hydrogen by 2050 in all scenarios, mainly trading with Finland. This indicates a potential domestic hydrogen

shortfall relative to the foreseen demand from the iron and steel industry and e-fuels production. In reality, this type of shortage situation would likely result in some announced industrial or e-fuel production plans being postponed, moved elsewhere, or cancelled altogether, but this type of feedback is not captured in the modelling. Also, note that the hydrogen trade outcome is sensitive to the wind power deployment limitations assumed for Sweden; with more domestic wind power production, domestic green hydrogen production could increase, causing imports to drop.

CO₂-emissions

Figure 2A.8 shows CO₂ emissions by sector in Norway and Sweden, for 2030 and 2050, across the different scenarios. In both countries, industry, fuel refineries, and transportation account for almost all current CO₂ emissions. Between 2030 and 2050, total CO₂ emissions drop significantly in all scenarios, most notably from transportation through a combination of electrification and the use of biofuels and synthetic e-fuels. For the industry sector, which is the focus here, the resulting emissions are sensitive to the underlying demand assumptions and the Trinity and GoRES frameworks, encompassing different clean energy technology costs and CO₂ prices.

GoRES drives deeper abatement in both countries through a combination of lower clean energy technology costs and higher CO₂ prices (e.g. 420 Euro/ton vs. 160 Euro/ton in 2050).

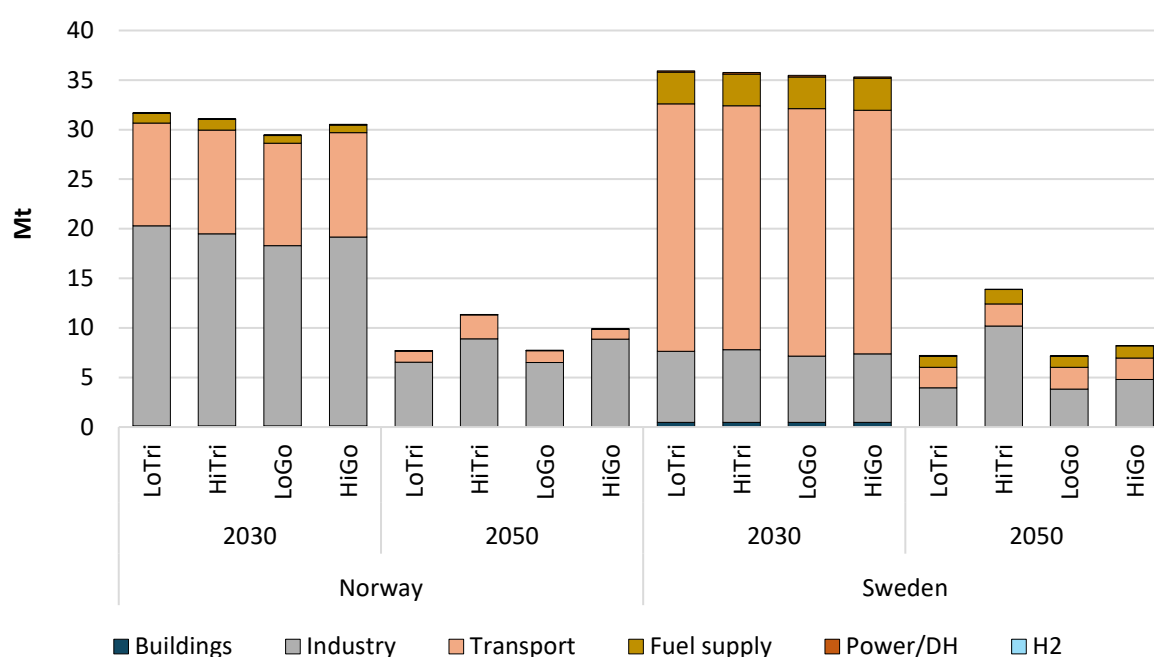


Figure 2A.8. CO₂ emissions (Mt) in Norway and Sweden across scenarios in 2030 and 2050. Industry emissions include both energy-related fossil-based and process emissions (e.g. from cement production).

In Norway, industrial emissions decline strongly in both scenario groups, largely due to a shift from fossil fuels to electricity or hydrogen; however, hard-to-abate emissions remain, particularly in cement production and the non-ferrous metals industry. The difference in industrial emissions between the Trinity and GoRES scenarios is negligible, despite CO₂ prices varying from 160 Euro/ton (Trinity) to 420 Euro/ton (GoRES) in 2050, further emphasising the hard-to-abate nature of certain industrial emissions, which call for other solutions such as CCS.



For Sweden, the resulting emissions are diverging across scenarios in 2050. Under the Trinity assumptions, and with high industrial energy demand, CO₂ emissions even increase. In the GoRES cases, with lower costs on clean energy technologies and a higher CO₂ price, industrial emissions are reduced through a combination of electrification and the use of green hydrogen. Yet, as in Norway, hard-to-abate emissions persist, particularly in cement production and in metals and minerals production.

Summary

Taken together, the results of the model-based scenario analysis showcase the different future roles that Norway and Sweden can play within the European energy transition, determined by a combination of domestic and international factors. With low domestic demand from industry, and little or no new industries being established, and with a slow European transition overall (LoTri), Norway's and Sweden's roles as net providers of low-carbon energy commodities (electricity and hydrogen) persist. With high domestic demand, following the electrification of existing industries and the establishment of announced new energy-intensive facilities, the two countries combined become net importers of electricity, but instead export large volumes of hydrogen (Norway) and green industrial products (Sweden in particular), which may substitute more carbon-intensive production elsewhere. With the modelling assumptions used here, neither scenario can fully decarbonise industry and achieve net-zero emissions by mid-century, underscoring the hard-to-abate nature of (some of) the energy-intensive Nordic industry, requiring additional solutions—technical (such as CCS) or natural—and specific policy support besides a general price on CO₂.

2A.4.2. NECPs

This section entails the NECP-related discussions from Part A and Part B of CS2, as both focus on the same region.

Norway

Norway, as a non-EU country, is not obliged to send updated NECPs to the European Commission. Still, Norway sent an NECP in 2019 but has now adapted the work in a separate process through the Norwegian climate plan⁴. This plan indicates the policy priorities within different sectors, and for CS2, it is of interest to look for policies and ambitions with a direct impact on the power system. This includes policies that change demand or policies that change the energy mix in the system, or lead to significant changes in the transmission and medium voltage distribution systems. The text in ***bold italic*** is how we have responded to the information in CS2 Part B.

The Climate plan states that the Norwegian government will pursue an energy policy based on the premise that access to renewable power should be a competitive advantage for Norwegian industry. This involves increased power production, enhanced domestic transmission capacity in the grid, and more efficient use of energy in the system. ***The increased transmission capacity of the sensitivity scenarios is not in line with this policy, which requires that the power system Norway should remain a surplus area compared to neighbouring countries.***

Huge step-up in offshore wind and a concrete action is to build 30 GW offshore wind before 2040: ***This is a system change which we have considered in our modelling.***

⁴ See <https://www.regjeringen.no/contentassets/1b2fd715fe494bd886a4756a49737670/no/pdfs/regjeringens-klimastatus-og-plan.pdf>



To enable transition relevant energy projects, more resources will be given to concession processes: ***This is in line with the REPowerEU pointing to wind as a growing technology in the energy mix and argues that the transition in NECP-Essentials is possible to achieve also for Norway.***

Improved efficient energy use: ***This aspect is explored in the case study through: (Part A) by adjusting relevant TIMES parameters., (Part B) modelling of different principles for demand flexibility as load shifting or modelling of price sensitivity demand.***

No sector specific reduction targets are or will be developed, but the climate plan has a long list of suggested policy actions, and a couple of them are mentioned below:

E.g. CO₂ tax is set to 1400 NOK/Ton in 2025: ***In our calculation this is not directly relevant as there is no thermal power generation in land-based Norway. On the other hand, the tax impacts on electrification rate of the industry, which is included in our studies, as increased electricity demand.***

E.g. support to charging infrastructure for zero-emission heavy transport 3,7 BNOK: ***Our calculations consider growth in electricity demand, which includes the increase in electric transport.***

The governing concept of the Climate Plan (see Figure 2A.9) is that the progress in emission reduction will be assessed and the plan updated and revised yearly according to the calendar of the Norwegian Government.



Figure 2A.9. Norwegian Climate Plan management.

Considering the actual progress towards the climate goal, this should show whether the existing measures are effective or if additional measures are needed. At the time of release of the climate plan, emissions had been reduced by 9% compared to the 1990 level, while GDP had doubled and the population had increased by 1.3 million.



Looking forward, the climate plan indicates emission reduction in selected sectors towards 2030 (check Figure 2A.10), meaning that our calculations need to extrapolate or adopt the same development towards 2050. The short horizon is a limiting factor, as investments in the energy transition policies need to have a longer perspective to justify and give direction to the required investments.

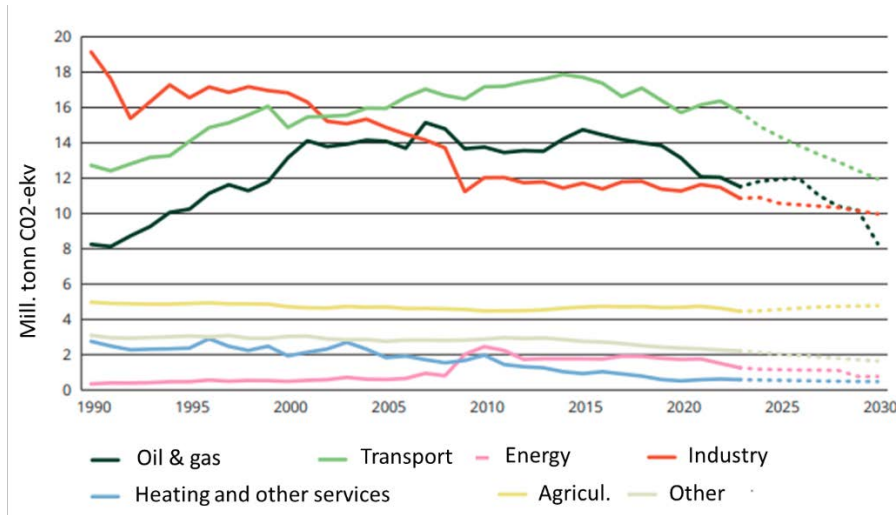


Figure 2A.10. Sector wise reductions in Norway towards 2030 (Norwegian climate plan⁵).

The Norwegian Climate Plan does not consider the benefits across the Nordic countries of joint actions or collaboration towards the EU policies on emission reduction. The Nordic power market shares regulation and the Nordic region is strongly interconnected through the power grid. Changes in the Norwegian power sector will impact the other Nordic countries and vice versa – this must be included in and accounted for in the respective NECPs. Therefore, while the Nordic power system development varies in terms of policy, the actual integration level is already quite high.

Sweden

The most recent update of the Swedish NECP 2021–2030 was submitted in June 2024 (KN2024/00362). The plan includes three types of targets (described below), and outlines expected developments under a baseline scenario. The baseline scenario is primarily based on national long-term scenarios developed by the Swedish Energy Agency, rather than the EU reference scenario. Renewable shares are calculated according to the methodology defined in the Renewable Energy Directive (Dir 2009/28/EC), with results presented across the Swedish Energy Agency baseline and sensitivity cases.

1 Climate targets

Sweden's binding EU target under the Effort Sharing Regulation (ESR) (i.e. excluding industry, refineries, heat and power, which are covered by the EU ETS) is to reduce greenhouse gas emissions by 50% to 2030 compared to 2005, corresponding to a reduction to 21.6 Mt CO₂-eq. in 2030.

Expectations (based on current policies and scenarios): Based on the baseline scenario (including adopted policy instruments), emissions are expected to reach 25.3 Mt CO₂-eq. in 2030. In the

⁵ See <https://www.regjeringen.no/contentassets/1b2fd715fe494bd886a4756a49737670/no/pdfs/regjeringens-klimastatus-og-plan.pdf> (accessed on 28 March 2026).

transport sensitivity case, emissions are expected to decrease further to 24.3 Mt CO₂-eq. in 2030. This implies that the ESR target is not met under current policies. After accounting for banking of surplus (2021–2023) and use of EU ETS allowances, an accumulated deficit of approximately 1–9 Mt CO₂-eq. over 2021–2030 is projected.

Complementary target for land-use and forestry (LULUCF) sectors: Sweden is required to increase net removals to approximately 49 Mt CO₂-eq. by 2030 (about 4 Mt higher than the 2016–2018 average).

Expectations:

Net removals are estimated at:

- Around 42 Mt CO₂-eq. (average growth scenario) → gap of ~7 Mt
- Around 29 Mt CO₂-eq. (reduced growth scenario) → gap of ~19 Mt

2. Renewable energy targets

Sweden does not express a new explicit national target in the NECP but contributes to the EU-wide target under the Renewable Energy Directive (RED), i.e. 42.5% renewables in the energy mix by 2030. The share of renewable energy is the key indicator used for compliance. In the current NECP, Sweden also includes nuclear in the renewables target, with the motivation that nuclear is fossil-free.

Expectations:

- The share of renewable energy is expected to increase from 66% in 2022 to 67% in 2030 (baseline scenario).
- Fossil-free nuclear electricity production is estimated at 52 TWh in 2030.
- The combined share of fossil-free energy (renewables and nuclear) is expected to reach 78% in 2030.

3. Energy efficiency targets

Sweden's indicative national contribution to the EU energy efficiency target is 350 TWh of total final energy consumption in 2030. Additional targets relate to accumulated end-use energy savings under the Energy Efficiency Directive (EU) 2023/1791.

The government (2024) assesses that Sweden's energy efficiency targets should be revised to better promote cost-effective energy use and support the green transition. The current targets are not aligned with industrial electrification, the goal of 100% fossil-free electricity by 2040, or updated EU directives.

Energy use developments are based on a baseline scenario using:

- Adopted policy instruments (as of 30 June 2023)
- Assumptions on fossil fuel and carbon prices from the European Commission
- A sensitivity case with adjusted (lower) energy demand from transports, but it does not constitute a full alternative scenario.
- Expected energy savings in buildings with a focus on offices, schools and multi-family houses have been estimated by Chalmers Industriteknik (CIT) using scenarios in the HEFTIG simulation model. The reference scenarios show how energy use in buildings may develop under current or similar policy instruments and unchanged efficiency and renovation practices. Scenarios are available for multi-family buildings, schools, and offices, but not for other premises or single-family houses.



2A.4.3. Supplementary Data

Code and Data

To access the code and data for CS2 A, please contact the contributing authors listed on the second page of this report.

Part B: Stochastic Modelling of the Nordic power system

With the increasing importance of electrification in mind, this case study analyses how the power sector in Norway interacts with demand flexibility internally and externally with the European power system. Of particular interest is how hydropower, as a renewable energy source with 87 TWh storage capacity in Norway, can play a valuable role in European VRE integration, especially if the power sector can utilise internal demand flexibility to release more capacity to interact with Europe.

In the definition and planning of the power system study, our researchers have held discussions with the Norwegian industrial ManOEUVRE partners: *Statkraft*, *Hafslund* and *Equinor*. Initially, three different angles on the analysis were discussed:

- **Research Idea 1:** The potential future value of offshore wind power in Northern Norway and Sweden
- **Research Idea 2:** The future value of increased industrial demand-side flexibility and hydropower flexibility
- **Research Idea 3:** Investigate the inter-annual variability of future Norway-Sweden electricity exchange

In the dialog with the industry, several bilateral meetings were arranged for discussing the alternatives and obtain feedback for the Nordic power system analyses. The feedback informed a modified version of **Research Idea 2** with focus on power system flexibility was formulated, motivated by the following challenges:

- Managing the variability of wind and solar poses challenges across the Nordic power systems
- With growing deployment of wind and solar power, flexibility solutions become increasingly important
- Investments in demand-side flexibility and hydropower (generation) flexibility are two strategies to revenues while helping mitigate adverse system effects of variability
- As a stochastic model, FanSi is well-suited for analysing flexibility solutions in power systems with high VRE shares and various flexibility sources, including that of demand.

The discussions resulted in the definition of the following objective:

- Analyse how stylised expansions of industrial demand-side flexibility, hydropower flexibility and cross-border transmission capacity influence system operation, price formation and hydropower use in the ManOEUVRE NECP Essentials scenario for 2050.

This work uses the stochastic optimisation power market model *FanSi*, which is designed for hydropower-rich systems and applicable to a broad Northern European setting. FanSi maximises expected socio-economic surplus by optimally dispatching generation and transmission capacity while explicitly representing hydropower reservoir dynamics and other temporal couplings. Approximately 1300 individual hydropower modules are represented in the FanSi dataset. In this work, simulations



are performed for thirty historical weather years (1991-2020) based on detailed weather data for precipitation, temperature, and production from wind and solar. This allows the model to provide the solution space spanned by weather variability. Thus, findings from FanSi will include variability in the simulated revenues for power producers and costs for consumers, as well as power prices and power exchange between regions.

2B.1 Accomplished Tasks

This section summarises the work the case study.

Definition of Power System Scenarios

The following list provides an overview of the scenarios that are analysed with FanSi. The starting point for these scenarios is given by the Man0EUvRE's NECP-Essentials scenario, and results from GENeSYS-MOD provides the framework for the power system scenarios analysed with FanSi in the case study. The Base scenario serves as the reference case. The other scenarios represent variations designed to explore four distinct dimensions of system flexibility:

- **Base:** The reference case and the default FanSi implementation the NECP Essentials scenario from GENeSYS-MOD.
- **+HydroFlex:** Add a total of 11 GW generation and 5.2 GW pumping capacity. The added capacities are distributed over twelve locations, of which five are in the area NO-WESTMID, three in NO-WESTSOUTH, three in NO-SOUTH and one in NO-INLAND1.
- **+ElasticDemand:** Introduction of price-responsive demand for 22 TWh load in the areas NO-WESTMID, NO-WESTSOUTH and NO-SOUTH. Demand flexibility is represented through a price elasticity function allowing load to respond to market prices.
- **+TimeShiftDemand:** Add temporal demand-shifting capability for a total of 22 TWh load in total in the areas NO-WESTMID, NO-WESTSOUTH and NO-SOUTH. Demand shifting is represented through energy storage with 9-hour storage duration.
- **+TransFlex:** Add a total of 4.9 GW transmission capacity by doubling the Base transmission capacities between Norway and the United Kingdom, Germany and the Netherlands. The Norwegian areas involved are NO-WESTMID, NO-WESTSOUTH and NO-SOUTH.

Hereafter, the scenario variants listed above are referred to simply as *scenarios*.

With the partial exception of +HydroFlex, the flexibility scenarios are intentionally stylised and do not represent assessments of real-world flexibility potentials. The absolute magnitudes of the implemented flexibility options are not intended to be comparable across scenarios, as there is no consistent empirical basis for calibrating, for example, how much demand elasticity, time-shifting capability or transmission expansion to assume. Rather than enabling absolute comparisons, the purpose of the scenario variants is to explore system impacts associated with distinct types of flexibility and to support relative comparisons across qualitatively different flexibility mechanisms. Another point to note is that the FanSi analyses reflect only operational outcomes and do not consider investment costs associated with flexibility or any other investment costs.

While the geographical scope of FanSi is Northern Europe, the variations in flexibility assumptions across scenarios mentioned above will focus on southern Norway, with emphasis on the areas NO-SOUTH, NO-WESTSOUTH and NO-WESTMID. The scenarios are explained in more detail in the following subsections.

Expansion of Norwegian hydropower



The +HydroFlex is based on the list of applicable hydropower flexibility projects from the CEDREN-HydroBalance project (Solvang et al., 2014) implemented in a FanSi dataset by the KSP HydroConnect project 2021-2024). Hydropower expansions should be situated in areas with significant hydropower potential, which underscores the continued relevance of results from CEDREN-HydroBalance. The list of projects is within the current regulation schemes and respect the recommended maximum water level change per hour, 13 cm/hour, as defined by CEDREN. All projects consider existing hydropower reservoirs only and no new reservoirs are added to the hydropower system. The proposed expansion is therefore realistic in terms of water level variability in the reservoirs.

Relation of the scenarios to the project HydroConnect (2021-2024)⁶: HydroConnect already analysed power system impacts of implementing all twelve projects included in Table 2B.1 under a future European energy system scenario. The present Man0EUvRE analysis is distinguished from the HydroConnect analysis by using GENeSYS-MOD scenarios as frameworks, which are different from the energy system scenarios used in HydroConnect (e.g. different electricity mixes in Europe).

Table 2B.1. Increases in hydropower generation and pumping capacity included in the +Hydroflex scenario. The added capacities are distributed over twelve locations as previously identified in the CEDREN-HydroBalance project (Solvang et al., 2012) and implemented in FanSi in the HydroConnect project (Harby et al., 2026).

Power plant	Lower reservoir	Upper reservoir	Increased generation (MW)	Increased pumping (MW)	FanSi area
Tonstad	Sirdalsvatn	Nesjen	1400	1400	NO-SOUTH
Holen	Botsvatn	Urarvatn	700	700	NO-SOUTH
Lysebotn	Lysefjorden	Lyngsvatn	1400	-	NO-SOUTH
Tysso	Ringedalsvatn	Langevatn	700	700	NO-WESTSOUTH
Jøsenfjord	Jøsenfjord	Blåsjø	1400	-	NO-WESTSOUTH
Oksla	Hardangerfjord	Ringedalsvatn	700	-	NO-WESTSOUTH
Tinnsjø	Tinnsjø	Møsvatn	1000	1000	NO-INLAND1
Mauranger	Hardangerfjord	Juklavatn	400	-	NO-WESTMID
Sy-Sima	Hardangerfjord	Sysenvatn	700	-	NO-WESTMID
Aurland	Aurlandsfjord	Viddalsvatn	700	-	NO-WESTMID
Tyin	Årdalsvatn	Tyin	700	-	NO-WESTMID
Kvilldal	Suldalsvatn	Blåsjø	1400	1400	NO-WESTMID

2B.2. Planned impact

By combining a long-term energy system scenario for the year 2050 from GENeSYS-MOD with a detailed stochastic power market representation in FanSi, this case study contributes to power system flexibility research by assessing how different flexibility mechanisms influence operational outcomes in a future Northern European electricity system characterised by high shares of VRE.

This work also contributes to the knowledge about the importance of stochastic modelling in RES-dominated power systems by accounting for both weather uncertainty, through stochastic optimisation, and inter-annual variability, by simulating 30 historical weather years. Such stochastic and multiyear optimisation becomes increasingly important as the transition towards the low-emission power and energy system progresses and the RES share in the power system increases. The analysis sheds light on the system-level roles and mechanisms of hydropower flexibility, demand-side

⁶ <https://www.sintef.no/en/projects/2021/hydroconnect/> (accessed on 28 March 2026)



flexibility and transmission expansion, and reveals how each can shape price formation, hydropower operation and system dynamics in a high-renewables future scenario for Europe.

Finally, the study discusses how the obtained results are aligned with the framework provided by the results of the GENeSYS-MOD's NECP Essentials scenario. This includes the quality check of GENeSYS-MOD results when setting up data for the five calculations in the FanSi model and a discussion over the obtained values for the power system from GENeSYS-MOD.

2B.3. Implementation

As the framework for our analyses with FanSi, we use one of the openly available EU EnVis-2060 energy transition scenarios for Europe, namely NECP Essentials, which reflects National Energy and Climate Plans (NECPs) to 2040 and a continuation of current trends thereafter. Specifically, we use NECP Essentials (Löffler et al., 2024), which includes adjustments for Norway and Sweden relative to earlier releases.

We systematically transfer the NECP Essentials scenario results from GENeSYS-MOD to FanSi, enabling a coherent representation of the 2050 European energy system and Nordic power system operation. This implementation builds upon and further develop routines and code previously developed in the HydroConnect project (Harby et al., 2026; Arvesen et al., 2026) to transfer data from cross-sectoral capacity expansion energy system models into FanSi.

The data transfer from GENeSYS-MOD to FanSi includes GENeSYS-MOD variables representing installed generation capacities (onshore wind, offshore wind, solar power, thermal power from bio and gas, and nuclear), demand (industry, buildings, transport and a residual category), transmission capacities, and energy storage (pumped storage hydropower, Li-ion battery storage systems).

2B.3.1. Challenges

The adaptation to the ManOEUVRE scenario includes many assumptions and decisions about how the single node results from GENeSYS-MOD for Norway and Sweden are translated to a power system model of the Nordic System with several nodes per country, see Figure 2B.1.

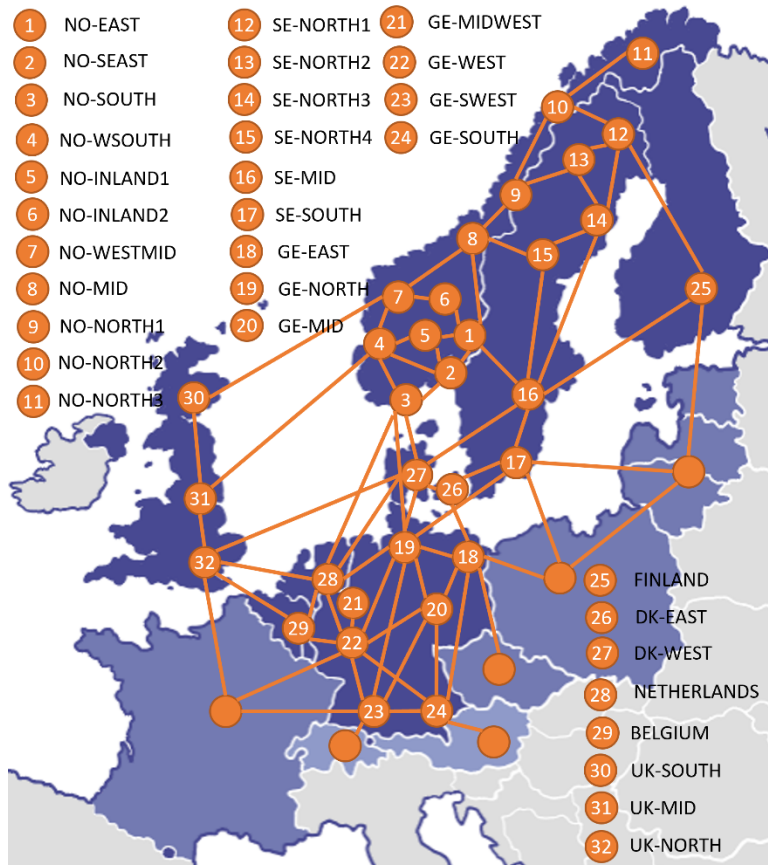


Figure 2B.1. Map of the power system modelled with FanSi. The circles represent the geographic regions included in the model. To streamline the figure, only the areas that are most relevant to the analysis or selected for results presentation are labelled, while other modelled areas, depicted with circles, remain unnamed. Darker blue shades indicate regions modelled with higher detail in terms of power demand and supply.

As indicated above, the scenario study of the Nordic power system is based on individual modelling of all reservoirs and hydropower plants in the system group around the water courses with cascaded modelling in addition to their location in the different price zones. The challenges are listed below:

- Transition from single-node representation to multiple-node representation for several countries
- Alignment of Norwegian and Swedish power demand and hydropower generation in the GENeSYS-MOD scenario with the published national scenarios
- Representation of flexibility in the GENeSYS-MOD scenario
- Installed capacity of power generation from coal and gas

2B.3.2. Mitigation Measures

Our approach coherently links results from the cross-sectoral capacity expansion model GENeSYS-MOD with the detailed operational model FanSi, enabling a consistent representation of the 2050 European energy system and Nordic power system operation. The countries Norway, Sweden, Denmark, United Kingdom and Germany are divided into multiple price areas in FanSi, allowing for the representation of geographical variabilities in renewable energy inflow and internal transmission constraints within countries. To disaggregate country-level results from GENeSYS-MOD into subnational areas defined in FanSi, a distribution algorithm has been designed using different



distribution factors for different parameters. An example of distribution factors can be seen in Table 2B.2 for onshore wind.

Table 2B.2. Distribution factors for onshore wind. The relative shares of all areas in one country can be summarised to one.

Node	Area name	Rel. share	Node	Area name	Rel. Share
1	NO-EAST	0.1	17	SW-SOUTH	0.17
2	NO-SEAST	0.1	18	GE-EAST	0.14
3	NO-SOUTH	0.1	19	GE-NORTH	0.09
4	NO-WSOUTH	0.1	20	GE-MID	0.14
5	NO-INLAND1	0.05	21	GE-MIDWEST	0.00
6	NO-INLAND2	0.05	22	GE-WEST	0.37
7	NO-WESTMID	0.1	23	GE-SWEST	0.17
8	NO-MID	0.1	24	GE-SOUTH	0.12
9	NO-NORTH1	0.1	25	FINLAND	1.00
10	NO-NORTH2	0.1	26	DK-EAST	0.41
11	NO-NORTH3	0.1	27	DK-WEST	0.59
12	SW-NORTH1	0.17	28	NETHERLANDS	1.00
13	SW-NORTH2	0.17	29	BELGIUM	1.00
14	SW-NORTH3	0.08	30	UK-SOUTH	0.40
15	SW-NORTH4	0.08	31	UK-MID	0.40
16	SW-MID	0.33	32	UK-NORTH	0.20

The following parameters from GENeSYS-MOD are handled in a similar way in their adaptation to the more detailed geographical representation in the FanSi model. Demand categories include industry, buildings, transport and a residual category. Generation categories are onshore wind, offshore wind, solar power, thermal power from bio and gas, nuclear and battery energy storage systems. Electric Import/export capacities also need to be transferred from the GENeSYS-MOD results. The single value from GENeSYS-MOD is distributed relatively to the existing connections in the FanSi model. Similar electric losses as in the original dataset are used. Neither GENeSYS-MOD nor the FanSi model used here include internal losses in the nodes, which is a weakness as grid infrastructure build-up internal in each country or price zone is required to accommodate the increased import and export capacities found in GENeSYS-MOD.

Concerning GENeSYS-MOD results

In this process, we performed a check of the GENeSYS-MOD results and reported back to TU Berlin that the following values needed correction: Adjustment of electricity demand in Norway and Sweden to be approximately aligned with the national scenarios published by the national TSOs (Statnett and Svenska Kraftnät) and the Norwegian regulator (NVE).

Overall hydropower generation in Norway was set to a level aligned with the scenarios from the Norwegian regulator NVE. These improvements were discussed with WP2 (TU-Berlin) and led to new results where demand and hydropower generation were more in line with the Nordic scenarios available from the TSOs and NVE. In the updated GENeSYS-MOD model runs, the changes in demand and hydropower resulted in a significant increase in renewable generation from wind in Norway compared to the original GENeSYS-MOD results.

The total installed battery capacity in the modelled countries is ~165 GW in 2050. GENeSYS-MOD assumes 3-hours duration for the battery. Based on this, the installed battery capacity is approximately 500 GWh. Table 2B.3 shows the battery investment in the part of Europe SINTEF are analysing with the FanSi model.

Table 2B.3. Battery capacity (in GW) from GENeSYS-MOD for different years in NECP Essentials.

Area/Year	2035	2040	2045	2050
Belgium				1.6
Denmark			0.3	2.2
Finland	1.8	3.4	6.3	8.8
France		2.1	25.4	75.3
Germany			21.1	62.9
Netherlands			1.1	13.9
Norway			1.2	1.3
Sweden				
United Kingdom		2.8	12.3	30.6
Sum	1.8	5.5	55.4	164.4

Energy storage in hydropower reservoirs represents a possibility for long-term energy storage beyond what batteries can provide. Hydropower capacity in Norway, is 40 GW with 87 TWh of energy stored and therefore a theoretical duration of ~2000 hours. Energy content of the above battery capacity based on GENeSYS-Mod is estimated to be 0.5 TWh, which is much lower compared to what was published in the HydroBalance project (Graabak et al., 2019), stating that 25 TWh of storage and 250 GW is needed in northern Europe to balance wind, solar, and load variability in a 100% renewable northern Europe.

While some coal and gas installed capacities remain in the results reported by GENeSYS-MOD for 2050, these inactive units have zero power generation in GENeSYS-MOD results for 2050. When transferred to FanSi, these capacities may be dispatched endogenously under certain price conditions. To support emissions consistency with the climate ambition underlying the NECP Essentials, these capacities are represented as equipped with carbon capture and storage (CCS) in FanSi, even though they are modelled without CCS in GENeSYS-MOD. This adjustment aims to prevent unrealistically high CO₂ emissions in the FanSi simulations.

2B.4 Results

2B.4.1. Outcomes

Average power price

The FanSi analysis shows significant differences in average price levels between Norway and continental Europe and the United Kingdom under the NECP-Essentials-based 2050 framework. The mean simulated power price is approximately 40 EUR MWh⁻¹ across all areas in Norway in the Base scenario (such as 40.1, 42.1 and 42.3 EUR MWh⁻¹ in NO-SOUTH, NO-WESTSOUTH and NO-WESTMID, respectively). In contrast, mean prices in the United Kingdom and continental European countries are substantially higher, at around 110 MWh⁻¹ in the Netherlands, 100 EUR MWh⁻¹ across UK areas and 70 EUR MWh⁻¹ across German areas.



The relatively low-price levels in Norway can likely be explained by the country's positive electricity balance in combination with limited transmission capacity to neighbouring countries. Differences in median prices across regions are considerably smaller than differences in mean prices, reflecting the influence of a limited number of hours with extremely high price in some areas (corresponding to unserved energy prices, as represented in the model). Expansions in transmission capacity in the +TransFlex scenario can reduce regional price differentials, as illustrated by Figure 2B.2, which presents median power prices for three Norwegian areas in Norway and four non-Norwegian areas as examples.

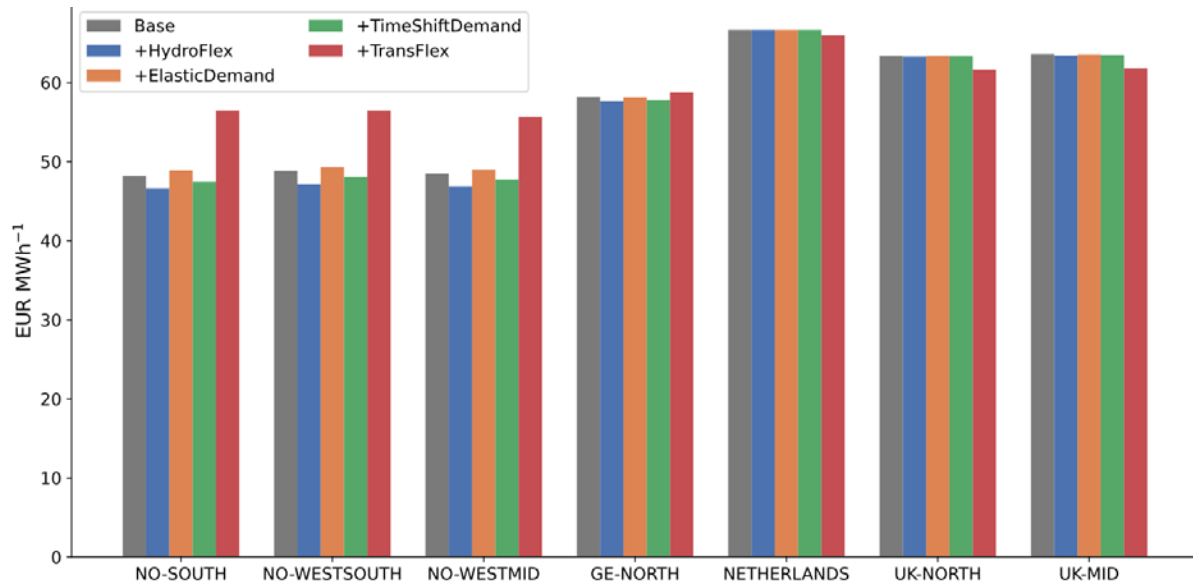


Figure 2B.2. Median power prices across 30 simulated weather years by scenario for seven selected areas (three areas in Norway and four in other countries).

Power price volatility

Figure 2B.3 provides comparisons of various price volatility indicators. Besides standard deviation and mean daily spread, the figure includes a measure of price volatility calculated in the following way: First, determine the differences between consecutive time steps at the given time resolution (3-hourly, daily or weekly). Next, calculate the standard deviation of these differences. All the indicators displayed are normalised to the mean price to facilitate comparisons across areas and scenarios.

Focusing on the Norwegian areas, shown in Figure 2B.3, and comparing the effects of the four flexibility scenarios in relative terms with the Base scenario as a common reference, we observe that the +HydroFlex and +TimeShiftDemand scenarios have relatively high efficacy in reducing the mean daily spread in Norway. For +HydroFlex, this effect is probably linked to extensive use of hydropower to balance day-night variations associated with the solar cycle in the simulations. The +ElasticDemand scenario shows moderate but consistent reductions for all analysed price volatility metrics, both short-term three-hourly and longer-term weekly metrics. +ElasticDemand is the only scenario that exhibits a notable reduction in week-to-week volatility in Norway ("volatility weekly" in Figure 2B.3).

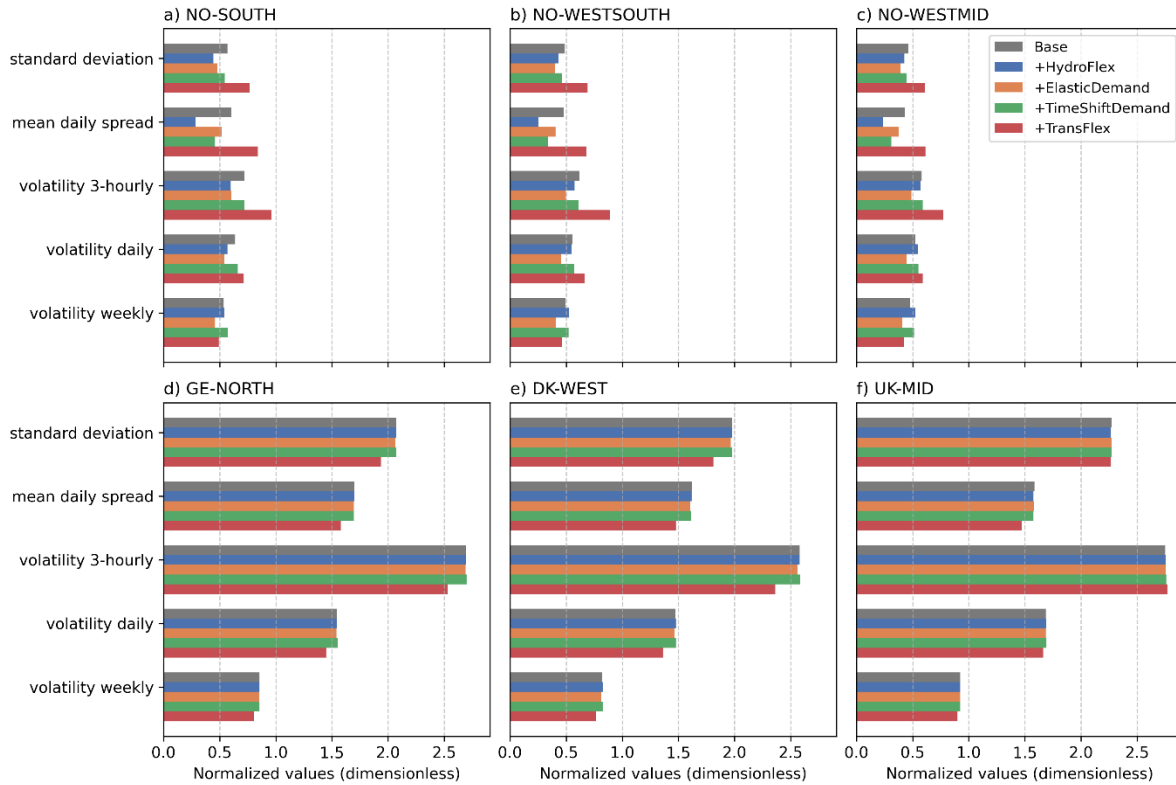


Figure 2B.3. Indicators of electricity price volatility. All metrics are normalised by the mean price, yielding dimensionless measures. The standard deviation is defined as the price standard deviation divided by the mean price. The mean daily spread corresponds to the mean daily range (daily maximum minus minimum) normalised by the mean price. The three other indicators labelled “volatility” are computed at 3-hourly, daily, and weekly time scales by: (i) calculating successive price changes at the selected temporal resolution; (ii) evaluating the standard deviation of these changes; and (iii) dividing the result by the mean price.

Price volatility increases in the +TransFlex scenario (reddish bars in Figure 2B.3) for Norwegian areas, because expanded interconnection exposes Norway more strongly to price variability in neighbouring markets, which exhibit higher volatility in the Base scenario. Conversely, in countries connected to Norway, the +TransFlex scenario tends to reduce price volatility.

Regardless of scenario, price volatility is substantially lower in Norwegian areas than in continental Europe and UK areas. This is the case for all the assessed indicators, but the difference is smaller for the weekly price volatility indicator than for the shorter-term indicators, as Figure 2B.3 illustrates. There is a tendency for the difference in price volatility between Norwegian areas and neighbouring areas to decline in the +TransFlex scenario, but the magnitude of this effect varies by country and indicator. It is important to note that volatility in our simulations is solely driven by weather variability, excluding factors such as variable fuel prices, and market and infrastructure changes.

Price duration curves show that all flexibility scenarios except +TransFlex result in increases in floor/low prices compared to the Base scenario in Norwegian areas, exemplified by Figure 2B.4 for the area NO-SOUTH. The results reveal particularly pronounced increases in peak/high prices and decreases in floor/low prices in the +TransFlex scenario compared to the Base scenario in Norwegian areas, particularly NO-SOUTH. These +TransFlex trends are mirrored by changes in continental Europe and the UK in the opposite direction (Figure 2B.5 showing results for UK-NORTH as an example).

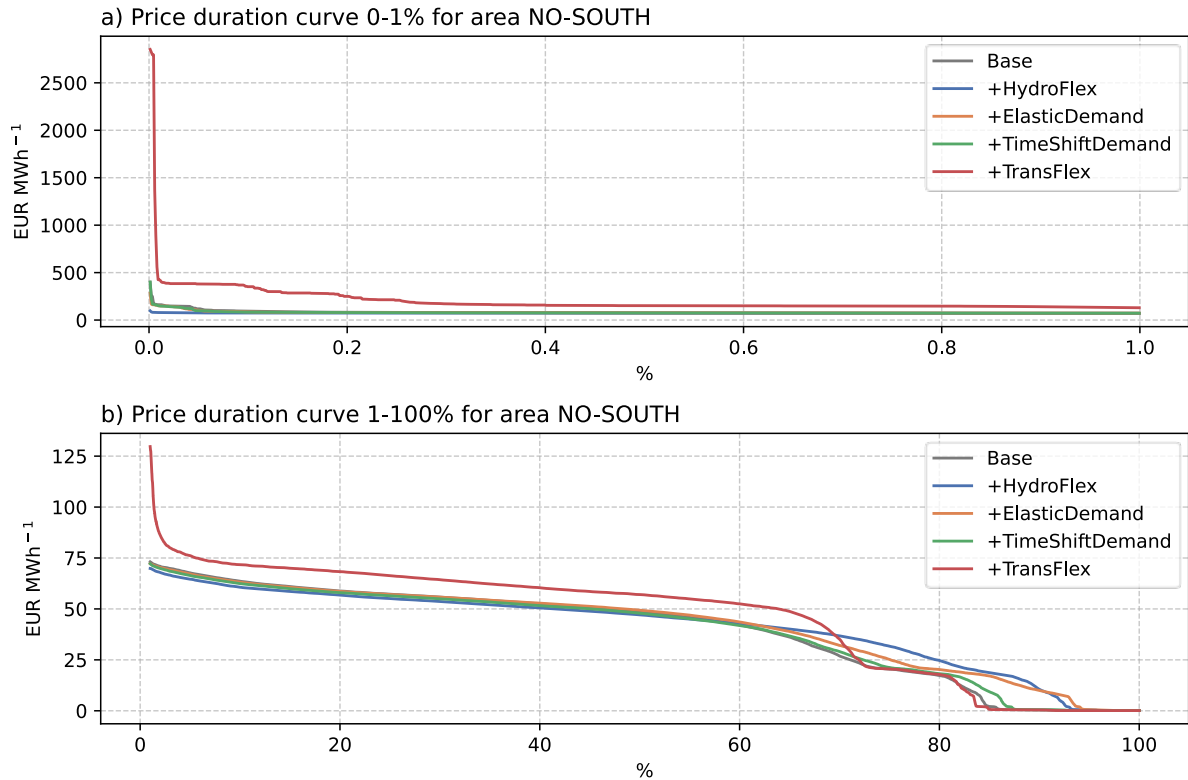


Figure 2B.4. Price duration curve for the a) 0-1% and b) 1-100% range of simulated power prices at three-hourly time resolution for the area NO-SOUTH.

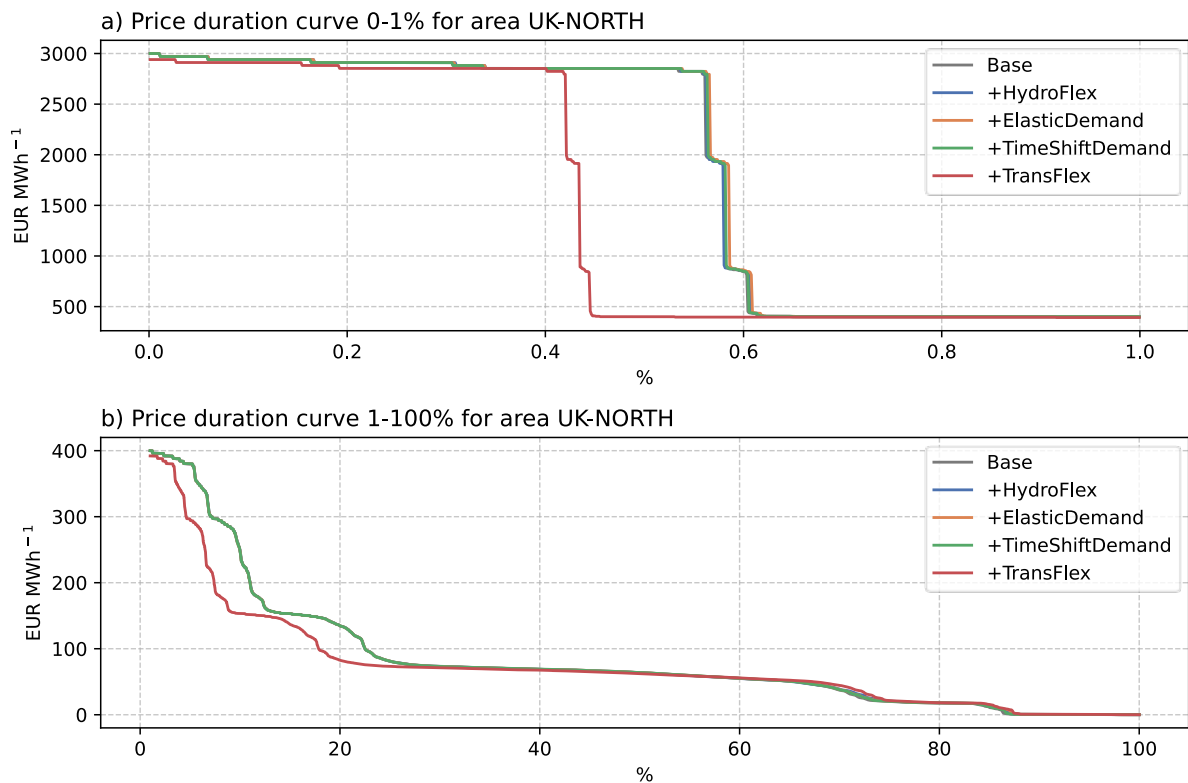


Figure 2B.5. Price duration curve for the a) 0-1% and b) 1-100% range of simulated power prices at three-hourly time resolution for the area UK-NORTH.



It is important to note that high-price outcomes are influenced by assumed curtailment thresholds for price-responsive demand in European countries. In the present setup, some demand segments are curtailed when prices exceed 300-400 EUR MWh⁻¹. These thresholds should be viewed as indicative of a system under stress as they reflect that some demand is already curtailed at these price levels. A scarcity of prices above these levels does not necessarily imply that the system faces no severe balancing challenges. High-price results should be interpreted with this modelling choice in mind.

Power price (intraday variability)

The solar diurnal cycle exerts a strong influence on the 24-hour daily power price variations for most parts of the year (apart from the winter weeks when solar power is at its lowest). Within Norway, this effect is most pronounced in NO-SOUTH due to its particularly strong interconnection with continental Europe. The influence of the solar diurnal cycle on power price in southern Norway is significantly reduced in the +HydroFlex, +ElasticDemand and +TimeShiftDemand scenarios compared to the Base scenario. However, this is not the case for the +TransFlex scenario, which rather shows a change in the opposite direction, with an increased influence of the solar intraday cycle. This result is consistent with the strengthened transmission between Norway and solar-rich regions under the +TransFlex scenario.

For nearby regions outside Norway, a weaker but consistent tendency for reduced solar diurnal influence is observed in the +HydroFlex scenario and, to a lesser degree, in the +TimeShiftDemand scenario. For the +TransFlex scenario, the effects are mixed and relatively small in magnitude, with some indications of lower night-time prices but slightly higher mid-day prices, making it difficult to identify a clear direction of change. A possible interpretation is that +TransFlex harmonises prices across areas rather than systematically dampening solar influence. These findings are illustrated by Figure 2B.6 and Figure 2B.7 for NO-SOUTH and UK-MID, respectively.

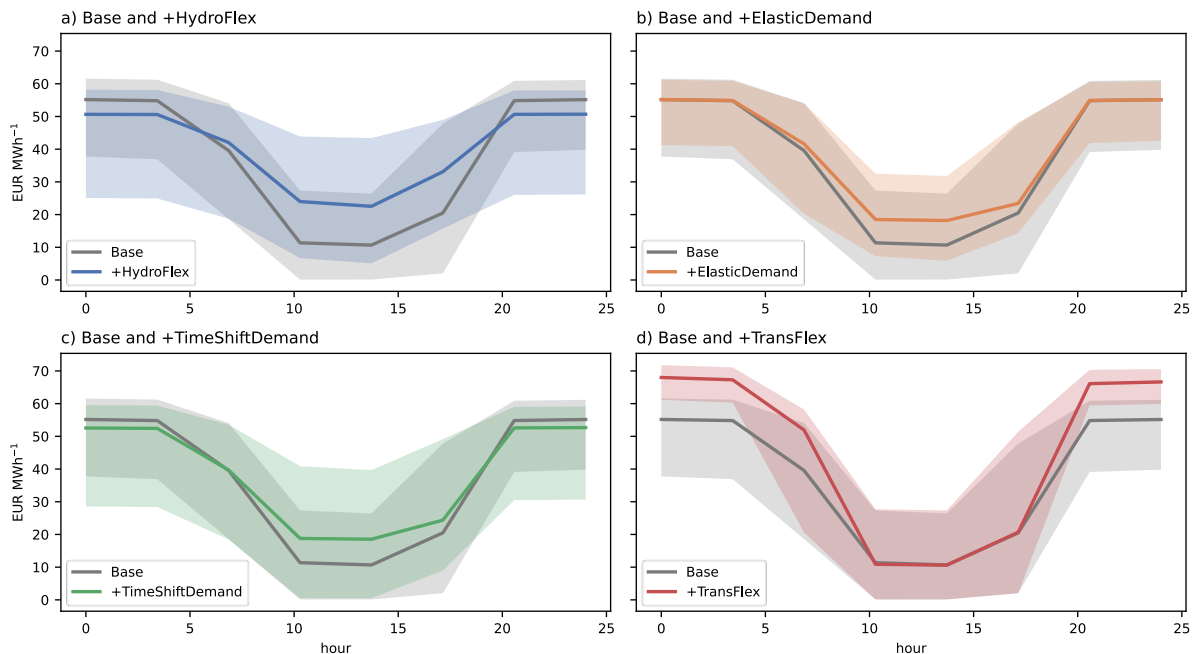


Figure 2B.6. Median (solid line) and 25th-75th percentile range (shaded area) for 24-hour daily profile for simulated price for NO-SOUTH during the summer months (June-August). The percentiles are calculated across all days in all years. Each subplot compares the Base scenario with one alternative scenario.

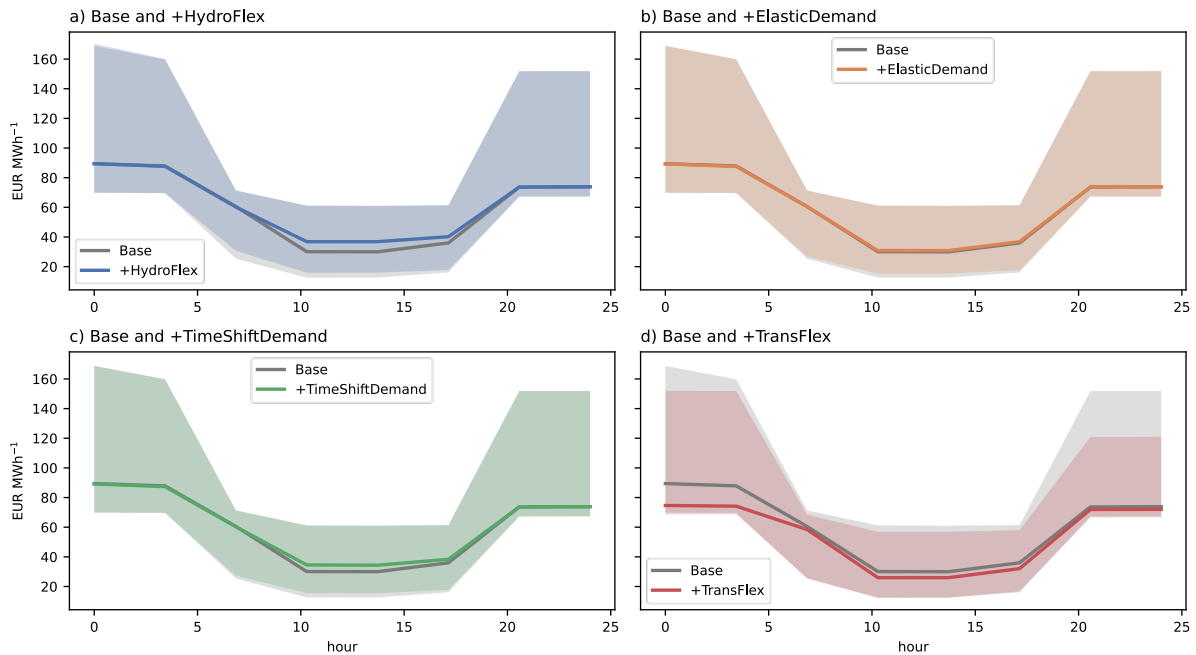


Figure 2B.7. Median (solid line) and 25th-75th percentile range (shaded area) for 24-hour daily profile for simulated price for UK-MID during the summer months (June-August). The percentiles are calculated across all days in all years. Each subplot compares the Base scenario with one alternative scenario.

Hydropower

The FanSi simulations indicate that hydropower flexibility is extensively used to balance the diurnal variability of solar generation outside the winter season. As shown by the summer profiles in Figure 2B.8, hydropower output closely mirrors the intraday solar cycle. This behaviour highlights a potential role of flexible hydropower in mitigating short-term variability in solar production.

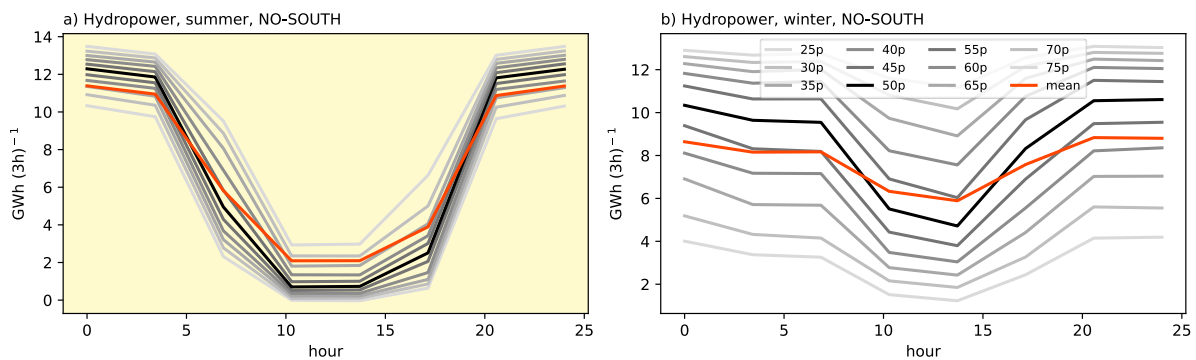


Figure 2B.8. Percentiles for 24-hour daily profiles for simulated hydropower generation during summer (panel a) and winter (panel b) seasons, respectively. The percentiles are calculated across all days in all years. Electricity used for pumping is counted as negative hydropower generation. The results are from the Base scenario and NO-SOUTH area as an example. Summer is taken as June-August, and winter as December-February.

Concerning the reservoir storage across the year, the higher assumed capacities in hydropower result in moderately higher reservoir storage levels on average in the +HydroFlex scenario relative to the Base scenario. However, the minimum and maximum observed levels across the year are only to a small degree affected. These results are illustrated in Figure 2B.9, which presents aggregated



Norwegian reservoir levels for the Base and +HydroFlex scenarios. Different dynamics are found for the +TransFlex scenario relative to the Base scenario, as the higher assumed capacities in Transmission in +TransFlex result in lower reservoir storage levels on average, and lower minimum and maximum levels, as illustrated in Figure 2B.10. These figures also illustrate that there is significant interannual variation in Norwegian hydropower reservoir management.

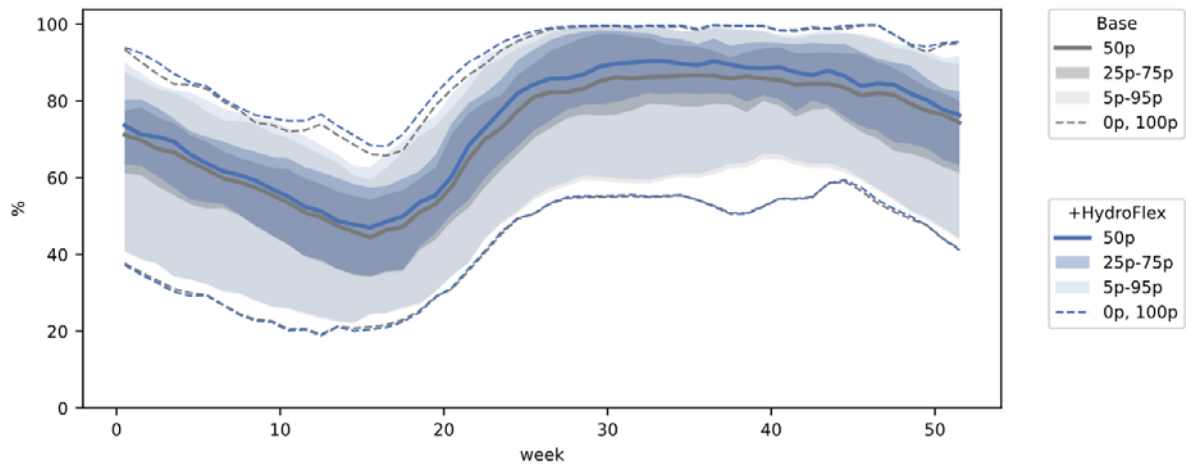


Figure 2B.9. Aggregated Norwegian reservoir levels in the Base and +HydroFlex scenarios. Reservoir levels are expressed as a percentage (%) of total maximum storage capacity. Solid lines show the median across 30 simulated weather years; dark shaded bands indicate the 25th-75th percentiles, light shaded bands the 5th-95th percentiles, and dashed lines the minimum and maximum values.

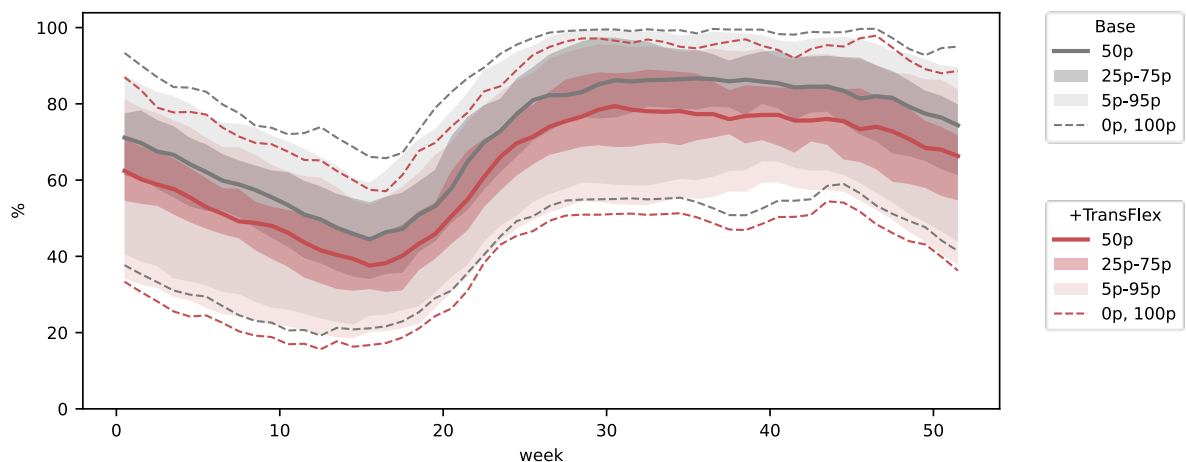


Figure 2B.10. Aggregated Norwegian reservoir levels in the Base and +TransFlex scenarios. Reservoir levels are expressed as a percentage (%) of total maximum storage capacity. Solid lines show the median across 30 simulated weather years; dark shaded bands indicate the 25th-75th percentiles, light shaded bands the 5th-95th percentiles, and dashed lines the minimum and maximum values.

Note that the FanSi simulation results for reservoir operation shown in the two previous figures only partially reflect the effects of short-term flexibility. In the stochastic second stage of the FanSi optimisation, water values are calculated at weekly resolution, which is too coarse to capture short-term flexibility in reservoir operation. As a result, the full impact on annual storage levels (as shown in the two previous figures) may not be fully represented.



Offshore wind power capture price

Regional price differences translate into differences in producer revenues. Figure 2B.11 illustrates this by showing mean capture prices for seven offshore wind power areas as examples. By capture price, we mean the ratio of the total revenue from selling electricity to the total electricity sold. As the figure illustrates, capture prices for Norwegian offshore wind power are substantially lower than capture prices for offshore wind power in most other areas. The Norwegian offshore wind capture prices are 43-44% lower than those for the UK and Benelux countries, and around 26% lower than those for Denmark. GE-NORTH is the main exception among the UK and continental European areas, with capture prices comparable to the Norwegian areas.

The lower capture prices in Norway are consistent with generally lower price levels, which in turn reflects Norway's significant net power surplus and limited interconnection capacity with Europe. Across the flexibility variants, Norwegian offshore wind capture prices increase moderately in the +HydroFlex, +ElasticDemand and +TransFlex, scenarios. For +HydroFlex and +ElasticDemand, this increase is primarily driven by higher prices during periods of high renewable power output compared to the Base case. By contrast, in the +TransFlex scenario, the increase in capture prices mainly reflects higher overall price levels in Norway, rather than a systematic increase when renewable power output is high. Under the given assumptions, +TransFlex (i.e. increasing the transmission capacities between Norway and other regions) is the most effective strategy for reducing cross-regional disparities in capture prices, leading to a more uniform revenues for offshore wind across areas.

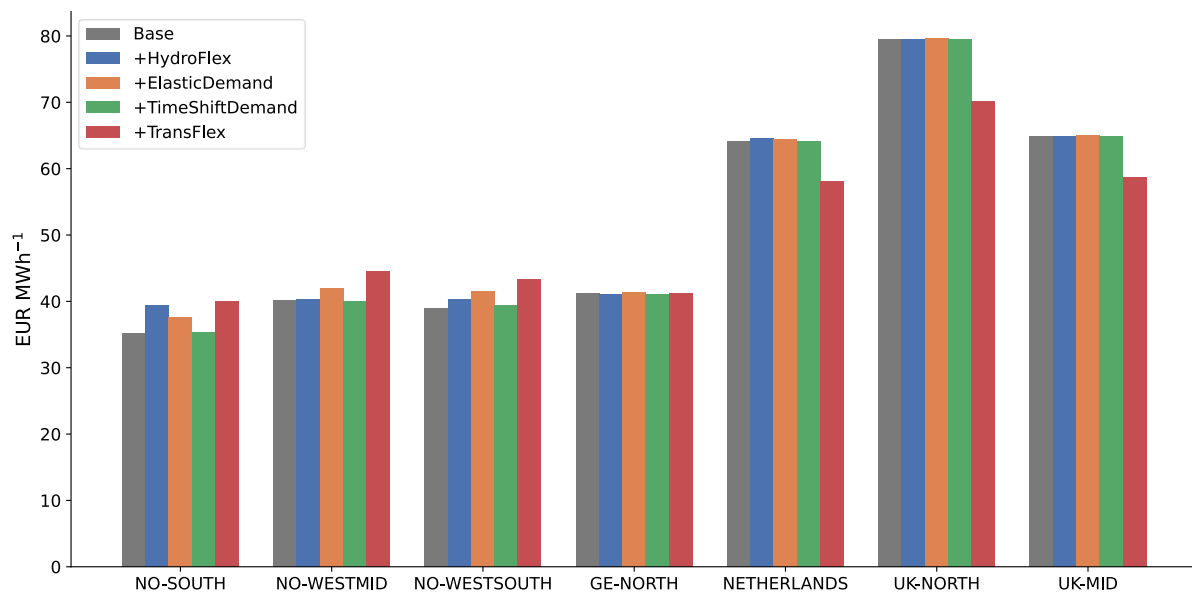


Figure 2B.11. Mean capture price across 30 simulated weather years by scenario for seven selected offshore wind farm areas (three areas in Norway and four in other countries).

Discussion and conclusions

By combining a long-term energy system scenario for the year 2050 from GENeSYS-MOD with a detailed stochastic power market representation in FanSi, this case study assesses how different flexibility mechanisms influence operational outcomes in a future Northern European electricity system characterised by high shares of variable renewable energy. We explore four flexibility scenario variants: hydropower flexibility (+HydroFlex), elastic electricity demand (+ElasticDemand), time-shifting of demand (+TimeShiftDemand) and transmission flexibility (+TransFlex). Each flexibility variant is juxtaposed against the Base case to isolate its system-level impacts.



The main findings and messages from the analysis are as follows.

- All flexibility scenarios except +TransFlex reduce price volatility in Norway relative to the Base case. In contrast, price volatility in Norway increases under +TransFlex because stronger interconnection exposes Norwegian prices more directly to higher volatility in neighbouring markets.
- +HydroFlex and +TimeShiftDemand appear particularly effective at mitigating short-term variability associated with the solar day-night cycle. This is reflected in significant reductions in mean daily price spreads and a weakened influence of solar generation on summer price formation, but more limited effects on day-to-day and week-to-week volatility.
- +ElasticDemand exhibits comparatively weaker impacts on intraday price spreads, but stronger reductions in day-to-day and week-to-week price volatility, indicating a greater relevance for managing stochastic variability associated with wind power. These interpretations could be further tested through analysis of individual low-wind and high-wind periods, which lies beyond the scope of the present study.
- +TransFlex primarily reduces regional differences, both differences in average price levels and in price volatility. As such, transmission expansion complements, rather than substitutes for, temporal flexibility options such as hydropower flexibility and demand-side response.
- Intraday variability driven by the solar day-night cycle exerts a strong influence on both power prices and Norwegian hydropower operation during most of the year (outside the winter season). Within Norway, this effect is most pronounced in the southernmost area (NO-SOUTH) due to its particularly strong interconnection with continental Europe.
- Norway's substantial net power surplus, mainly due to large wind capacities, leads to pronounced disparities in both average prices and price volatility between Norwegian areas and continental Europe and the UK areas.
- Such price differences have distributional consequences, illustrated by offshore wind capture prices 26–44% lower in Norway than in neighbouring markets.

There is substantial intrinsic uncertainty involved in modelling energy systems decades into the future. Uncertainty also arises from assumptions needed when integrating scenario results from GENeSYS-MOD into FanSi, and from the stylised representations of different forms of flexibility in our FanSi analysis. High-price outcomes should be interpreted with caution given the substantial uncertainties involved, especially the stylised curtailment thresholds for price-responsive demand and the representation of remaining coal capacities in the year 2050. It is also important to emphasise that the FanSi results capture operational effects only and do not account for investment costs, which should be considered when interpreting the findings. Finally, note that weather variability is the sole driver of volatility in our simulations, excluding factors such as variable fuel prices, and market and infrastructure changes.

Despite these uncertainties and modelling simplifications, the analysis sheds light on the system-level roles and mechanisms of hydropower flexibility, demand-side flexibility and transmission expansion, and reveals how each can shape price formation, hydropower operation and system dynamics in a high-renewables future scenario for Europe.

2B.4.2. Supplementary data

The electricity price results generated by FanSi for Case Study 2B are available on Zenodo: <https://zenodo.org/records/19218178> in IAMC format and in a 2D tabular format specific to SINTEF's power market models.



Case study 3: Global competitiveness and the energy demand of the energy-intensive industry

The transition to renewable energy does not affect all countries equally. For example, solar and wind resources are unevenly distributed across Europe and the world, creating persistent regional differences in the long-run cost of electricity. As electricity becomes an increasingly central input to industrial production — both for existing processes and for emerging technologies such as green hydrogen and electric arc furnaces — these cost differentials may alter where energy-intensive manufacturing takes place. This mechanism, often called the “renewable pull effect” (Samadi et al., 2023), is the central focus of Case Study 3.

The overarching research question is: how do heterogeneous renewable energy endowments affect industrial relocation and thereby country-specific energy demand in Europe? The answer has direct relevance for energy system planning, since most large-scale models — including GENeSYS-MOD used in this project — treat industrial demand as an exogenous input based on relatively stable sectoral structures. If industry migrates in response to energy cost changes, those demand assumptions may need to be revised. To address this question, the study develops a novel agent-based, multi-regional production-network model and applies it to a renewable endowment scenario derived from recent empirical estimates of regional renewable electricity generation potential (Kan et al., 2025).

Model Framework

The model is a discrete-time, agent-based simulation built with the open-source *sfctools* package developed at DLR (Baldauf, 2023). It represents 30 industrial product categories and 11 country or world regions, calibrated to the EXIOBASE 3.9 multi-regional input–output database (Stadler et al., 2025). Each industry–country pair is populated by at least 20 heterogeneous firms, making the model capable of capturing gradual, distributed adjustment dynamics rather than sharp sector-level switches.

Production, Costs, and Prices

Firms produce goods using intermediate inputs, labour, and energy. Unit production costs in a country therefore depend on the input–output coefficient matrix, labour intensity, energy intensity, and prevailing factor prices. Firms take prices as given and earn profits as the difference between revenues and total production costs. Energy and labour prices adjust endogenously in response to excess factor demand, with price elasticities controlling the speed of adjustment. Because intermediate inputs enter production costs, an energy price change in one sector propagates downstream through the input–output network, affecting sectors that may not themselves be directly energy-intensive.

Relocation Decisions

Firms periodically compare expected unit production costs across all modelled countries. If production is cheaper elsewhere, a firm may relocate — but the decision is probabilistic rather than deterministic, following a multinomial logit rule. Three types of friction slow or constrain relocation:

- **Home bias:** a penalty for moving abroad introduces inertia consistent with empirical evidence on firm attachment to existing locations.
- **Size penalty:** larger firms face higher relocation costs, capturing the real-world complexity of moving large production sites.



- **Congestion:** moving into a country-sector pair that already has many firms becomes increasingly costly, preventing unrealistically rapid agglomeration.

These frictions generate gradual, distributed reallocation patterns and ensure that cost advantages translate into industrial shifts over time rather than instantaneously.

Product Switching

An extension scenario allows firms to respond to rising costs not only by relocating but also by diversifying into technologically related products. This product-switching mechanism is constrained by a *product space* that encodes technological proximity between sectors (cf. Gräbner and Hornykewycz, 2022). Firms can only consider switching to products within a defined capability radius, reflecting path dependence, and the real-world constraint that industrial transformation requires existing competencies. In this extension, relocation remains the dominant adjustment channel, while product switching acts as a complementary margin that can dampen the need for relocation in some cases.

Scenario Design

The initial calibration establishes a stable production structure, in which trade and output decisions emerge endogenously from country-specific factor endowments and technological capabilities, without any policy or cost shock. All scenarios then apply a single exogenous shock: a permanent change in regional energy endowments implemented at mid-simulation (period 170 of 340), based on renewable electricity generation potential indices from Kan et al. (2025). The shock parameters reflect relative renewable cost advantages: Spain (+0.259) and France (+0.219) receive the largest positive shocks, followed by Greece (+0.211), Denmark (+0.207), Norway (+0.186), and Poland (+0.203), while Germany (−0.10) and the Netherlands (−0.10) face relatively less favourable endowments.

Five sensitivity scenarios are defined to test robustness. The baseline scenario permits relocation but prohibits product switching. Three robustness variants vary behavioural parameters: removing home bias, reducing the logit temperature (making choices more deterministic), and increasing cost sensitivity. A fifth extension scenario enables product switching within the capability-constrained product space. All scenarios are run for $T = 340$ simulation periods with 20 Monte Carlo repetitions each to account for stochastic variation.

3.1. Accomplished Tasks

Task 3.1 – Model set-up: The agent-based macroeconomic simulation model was constructed using *sfctools*, an open-source Python modelling framework developed at DLR (Baldauf, 2023). The model disaggregates energy-intensive economic sectors — including steel, chemicals, fertilisers, and motor vehicles — while treating other economic agents at an aggregated sectoral level. Country- and sector-specific knowledge stocks are parameterised using the product space method (cf. Gräbner and Hornykewycz, 2022). All input data are sourced from the EXIOBASE 3.9.5 multi-regional input–output database (Stadler et al., 2025), providing a consistent and internationally comparable representation of production, trade, and energy use.

Task 3.2 – Model calibration: The model was calibrated to reproduce an empirically consistent global production structure in a stable baseline state. Production and trade decisions emerge endogenously from country-specific factor endowments and technological capabilities, without any imposed policy



shock. This calibration phase served both as a validation of model plausibility and as the foundation for all subsequent scenario analyses.

Task 3.3 – Scenario Analysis: The calibrated model was used to explore how changes in renewable energy endowments affect industrial competitiveness and energy demand. Scenario analyses are aligned with the overarching European scenarios developed in the project and build on empirical renewable electricity generation potential estimates from Kan et al. (2025). The model was run across the five sensitivity scenarios. Results were evaluated in terms of changes in industrial location patterns, production structures, and final energy demand relative to the no-shock reference scenario.

Task 3.4 – Processing of results and contribution to European scenarios: Model output data have been processed and transferred to TU Berlin for integration into the GENeSYS-MOD European energy system scenarios. A conference paper presenting the methodology and results has been submitted to the European Energy Markets (EEM) 2026 conference. The model code and result data are being prepared for open-source publication via the DLR GitLab repository (<https://gitlab.com/dlr-ve/esy/sfctools/projects>) and the ManOEUVRE Zenodo community, ensuring transparency, replicability, and accessibility for third parties.

3.2. Planned Impact

By providing endogenous, dynamic projections of industrial energy demand, this case study can significantly improve the framing assumptions used in system cost optimisation modelling for Europe's energy transition. Understanding where and in which sectors industrial activity may grow or decline allows for more accurate allocation of renewable energy capacities, better-informed grid expansion decisions, and more effective sector integration across electricity, hydrogen, and heating.

3.3. Implementation

Industrial migration patterns are provided at the resolution of the product space and geographical scope used in the model (11 country regions, 30 product categories). Industrial energy demand is aggregated from production site-level estimates and compared to the assumptions in GENeSYS-MOD, providing a direct link between the agent-based simulation and the European energy system model.

3.3.1. Challenges

Given the complexity of the agent-based model and the required multi-step data processing, thorough documentation is essential for reproducibility and future usability.

3.3.2. Mitigation Measures

Standard documentation procedures are applied throughout, including version-controlled code, annotated calibration routines, and scenario specification files. These ensure that all model development steps and analytical choices are transparent and traceable.

3.4. Results

3.4.1. Outcomes

The model reveals two interconnected mechanisms through which renewable energy endowment shocks reshape industrial activity. First, **the direct cost channel**: countries that receive a positive endowment shock see their energy prices fall relative to others, making energy-intensive production more competitive and attracting firms from less-favoured locations. Second, **the network propagation**



channel: because firms rely on intermediate inputs produced by other sectors, higher energy costs in one sector raise input prices for downstream industries. This means that sectors with only moderate direct energy use can nonetheless face substantial cost pressure if they are heavily exposed to energy-intensive supply chains. The magnitude of these indirect effects depends on a sector's upstream position in the production network.

A recurring and initially counterintuitive pattern emerges in several scenarios: although firms initially migrate away from countries receiving a negative endowment shock, this outflow reduces domestic factor prices (e.g. wages) which can subsequently attract new production activities. In some cases, the aggregated output after the shock exceeds the no-shock baseline. This dynamic is consistent with classical trade theory (Heckscher–Ohlin–Samuelson) and illustrates the non-linear, path-dependent nature of industrial adaptation under changing energy cost structures.

Sectoral and Country-Level Effects

For the conducted simulations, the sectors showing the strongest relocation dynamics are motor vehicles (MOTO), machinery (MACH), fabricated metals (FABM), plastics (PLAS), and fertilisers (PFER). Importantly, the net effects on aggregate industrial energy demand at the country level are considerably more moderate than the structural reorganisation occurring within regional industry compositions. Most modelled countries show deviations of simulated energy demand of only 5–15% from the baseline⁷. The primary adjustment mechanism thus operates through sectoral restructuring and firm relocation rather than through large uniform shifts in total industrial energy use (see Figure 3.1).

In the baseline shock scenario, Denmark experiences an increase in industrial energy demand of approximately 20%, and Finland approximately 12%, both driven by their comparatively favourable renewable endowments. Germany shows a modest decline in energy demand of around 2%. Poland is a notable exception, with a decline of approximately 22%, reflecting the high share of energy costs in Polish industrial production and the consequently large incentive for firms to relocate.

⁷ It should be noted that these figures refer exclusively to the subset of manufacturing industries represented in the model, which are mapped to a reduced set of 11 countries and 30 product categories. Sectors not explicitly modelled — aggregated under "Other Industries" in the broader energy system context — are not subject to relocation dynamics in the current framework and are therefore excluded from these estimates. Final energy consumption by households and the service sector is likewise outside the model scope. The reported demand changes thus reflect restructuring within the modelled industrial segment only, and should not be interpreted as projections of total national energy demand.

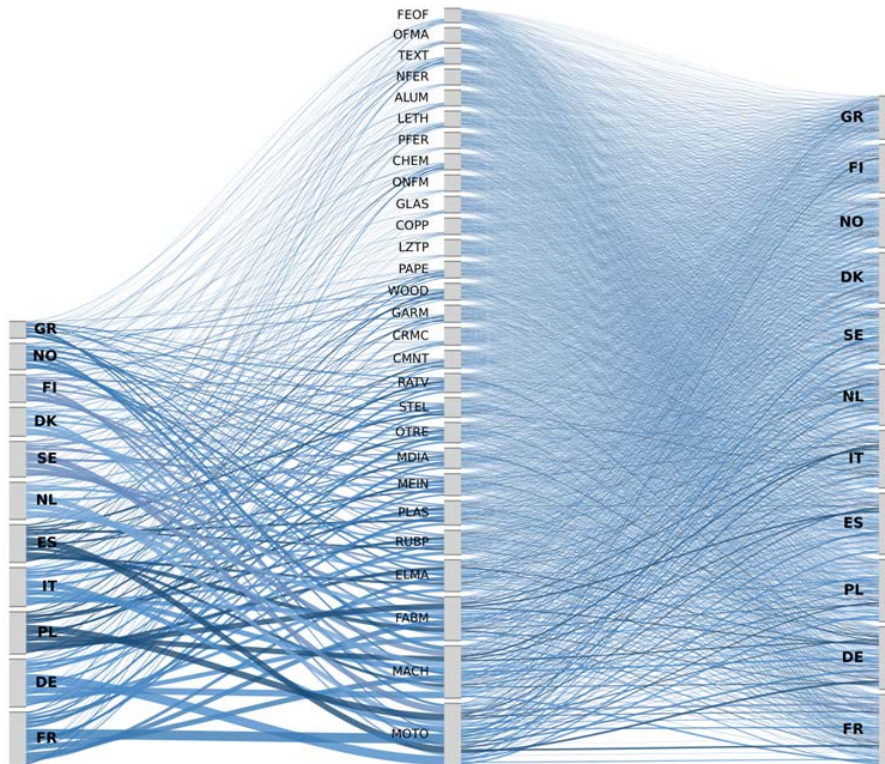


Figure 3.1. Model-derived reallocation of industrial activity following the energy endowment shock (baseline)

Sensitivity and Robustness

Qualitative adjustment patterns remain consistent across all five scenarios. Differences between scenarios primarily affect the magnitude of deviations, not their direction. Removing home bias or increasing cost sensitivity amplifies the relocation response, while a lower logit temperature produces somewhat more concentrated adjustments.

When product switching is enabled, deviations become more heterogeneous because part of the adjustment occurs through changes in sectoral specialisation: Energy-intensive production partly relocates while higher-complexity sectors tend to remain, potentially reducing the overall energy intensity of European industry (see Figure 3.2).

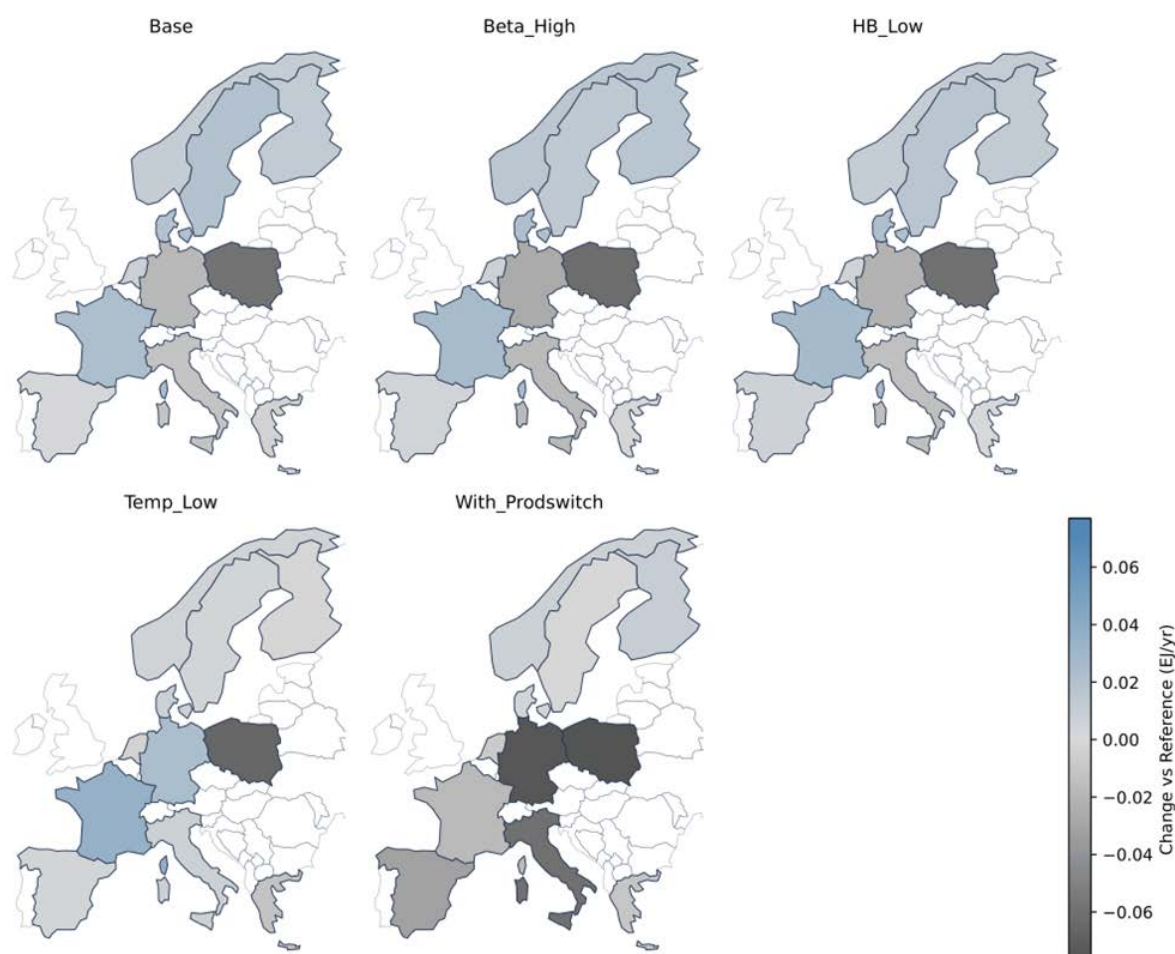


Figure 3.2. The maps illustrate spatial heterogeneity in sectoral changes in energy demand for different sensitivity scenarios.

3.4.2. NECPs

The simulation results offer quantitative, scenario-based insights into how changes in renewable energy endowments may reshape industrial activity across Europe, with direct relevance for the framing assumptions underlying NECPs. While the results are not yet sufficiently robust for direct integration into national energy planning — owing to the stylised model structure and the sensitivity of outcomes to behavioural parameters — they point to several mechanisms that current NECP frameworks may not adequately capture.

First, the findings suggest that differences in renewable resource availability will not simply determine which countries retain or lose existing industrial activity. In contrast, such differences will trigger more complex processes of restructuring and specialisation within Europe's production network. In particular, the model shows that energy cost differentials propagate through supply chains, meaning that even sectors with moderate direct energy use may experience significant cost pressure or competitive gains depending on their position in the input–output network.

Three sets of questions relevant to NECP implementation can be tentatively addressed on the basis of the current results:



1. **Comparative advantages in renewable energy:** Spain and France show the strongest positive endowment shocks in the simulated scenarios and tend to attract industrial activity under most scenario specifications. This suggests that countries investing in large-scale renewable deployment may gain in industrial competitiveness — a dynamic not captured in technology-only NECP modelling approaches.
2. **Deviations from current demand trajectories:** The simulations indicate that industrial energy demand in countries experiencing net industrial inflows — such as Denmark and Finland in the baseline shock scenario — may exceed current NECP projections, while countries with net outflows may fall below them. These deviations are sector-specific and parameter-sensitive; therefore, they should be treated as indicative rather than predictive.
3. **Regional imbalances and policy responses:** Relocation of industrial activity driven by energy cost differentials may exacerbate existing regional economic imbalances. The model results suggest that industrial policy and targeted infrastructure investment could shape adjustment trajectories, though the quantitative scope of such effects requires further validation.

Translating these findings into actionable inputs for NECP implementation will require further quantitative work, including tighter calibration of behavioural parameters, validation against observed relocation patterns, and closer alignment with the sectoral and temporal resolution used in national planning frameworks.

3.4.3. Supplementary Data

All datasets and configuration files used in this case study draw on open and reproducible sources. The primary input data come from the EXIOBASE 3.9 multi-regional input–output database (version 3.9.5; Stadler et al., 2025) and the renewable energy cost index published in Kan et al. (2025). The complete modelling framework — including pre-processing scripts, calibration routines, and scenario definitions — is being made available as an open-access resource at: <https://gitlab.com/dlr-ve/esy/sfctools/projects>

The results will be made available under <https://zenodo.org/communities/manOeuvre/> once internal approval processes are completed.

Case study 4: The role of growing demand in refinancing renewables

In this case study, the role of a growingly flexible power demand for refinancing renewable generators as well as flexibility options is analysed. For this purpose, the agent-based power market model *AMIRIS*⁸ is applied for the Federal Republic of Germany. *AMIRIS* has been extended by a generic representation of competing flexibility options. The model has been soft-coupled with *GENESYS-MOD* and uses input data from the EU EnVis-2060 scenarios. The results obtained are prepared to provide feedback to the German NECP.

4.1. Accomplished Tasks

Task 4.1 – Model extension/adaptation: In this task, necessary model extensions have been made to study the cost recovery potential for both renewable generators and flexibility options. This required the representation of competing flexible demand agents. A new generic approach to deal with

⁸ <https://helmholtz.software/software/amiris>



competing flexibility and their price repercussions has been implemented in AMIRIS to address this. At the beginning of the project, implementations already existed in AMIRIS for electric heat pumps and classical demand response. However, these were tailored for in-depth analyses and not ready to deploy across a broad set of scenarios. Neither did those implementations allow for studying competition among flexibility options. The controlled charging of electric vehicles was added in this task, in part building on previous work. The existing flexibility representations were generalised and transferred to the newly introduced approach to study competing flexibilities.

Task 4.2 – Model coupling and parameterisation: To parameterise the actual simulations, in this task, input data and results from the European EU EnVis-2060 scenarios (calculated in GENeSYS-MOD) have been prepared for the usage in AMIRIS using automated data workflows.

Task 4.3 – Model simulations: This task encapsulates all activities for the AMIRIS simulations. Different levels of flexible power demand have been studied. To allow for repeated and reproducible simulation runs, an automated model workflow has been developed. This workflow comprises the parameterisation from the data converter developed in the previous task, execution of an AMIRIS simulation with the processed data, and subsequent collection of results.

Task 4.4 – Processing of results and contribution of European scenarios: In the last task of CS4, the previously generated results have been further processed and evaluated. For the post-processing purpose, various criteria and indicators have been identified and analysed in an automated manner. Hereby, the cost recovery of flexibility technologies as well as of renewable generators has been the focus of the analyses. Besides, overarching metrics, such as average electricity prices, renewable energy curtailment and backup power generation have been calculated. Conclusions are derived from the observed effects of a flexible demand towards the refinancing of capacities as well as potential mitigation options in case of insufficient cost recovery. Those conclusions are used to inform the feedback on the German NECP in WP4.

4.2. Planned impact

The outcomes of this case study shed light on whether, and to what extent, increased demand and flexibility in the power sector and sector coupling technologies contribute to stabilising the refinancing situation of renewable energy sources in Germany. Also, the cost recovery potentials of flexibility technologies are assessed. These are pivotal questions to assess the necessity and extent of state-administered policy support for renewable generation technologies or flexibility options. In contrast to classical system cost minimisation approaches, our agent-based modelling approach allows to encapsulate business-oriented decision making as well as an anticipation of prognosed price repercussion and cannibalisation effects from competing flexibility options under uncertainty. Flexibility technologies seek to maximise their own profit rather than contributing to a system with minimal cost. A stable refinancing situation and a reduction of potential income risks ultimately is crucial to incentivise investors to deploy renewable generation as well as flexibility technologies. This addresses the prospect of achieving renewable energy sources expansion targets as set out in the NECPs.

4.3. Implementation

AMIRIS has been extended by a generic representation of flexibility units within Task 4.1, enabling the simulation of competing flexibility sources with defined dispatch strategies, e.g. profit maximisation. To achieve this, the flexibility options consider both their own price repercussions, as well as those observed for competitors. This is realised by an estimate of the merit order curve as shown in Figure

4.1. To estimate the collective price repercussion, competition multipliers are used. These multipliers are derived from the historical dispatch of a particular flexibility technology in comparison to the overall awards for flexibility technologies at past simulation time steps. The overall dispatch information is publicly available after market closure in Germany (BNetzA, 2026), such that the approach could be applied for real-world dispatch strategies as well. The new implementation was initially tested on storage units (Schimeczek et al., 2025). It has furthermore been expanded to flexible heat pumps, electric vehicles and load shifting. The prevalent analysis focusses on the first two, as they represent sector-coupling flexibility technologies, which are expected to form an increasing flexibility potential in the future (Geis et al., 2026).

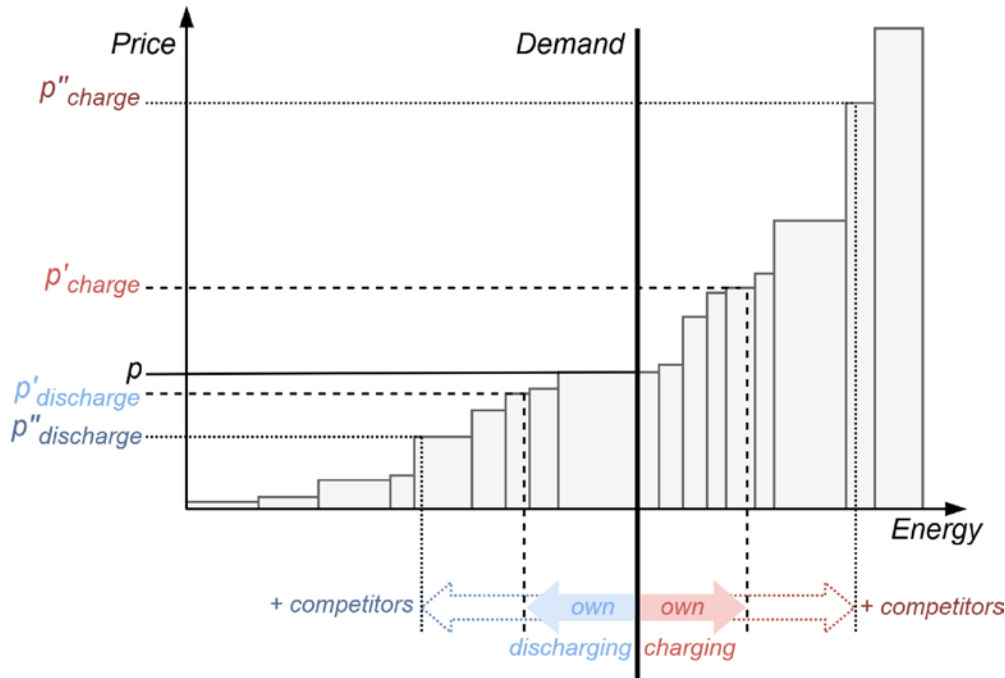


Figure 4.1. Illustration of the price repercussion of flexibility options. An estimate for the merit order is used. Both, the own as well as the collective price impact of competitors are assessed by analysing the clearing prices resulting from charging or discharging.

For the parameterisation of AMIRIS scenarios with data obtained from the EU EnVis-2060 scenarios, a data conversion script has been developed in Task 4.2. Capacities as well as cost information and profiles for renewable generation and demand are extracted from the GENeSYS-MOD results for the scenarios GoRES, NECP Essentials, REPowerEU++, and Trinity. Furthermore, as mentioned earlier, a workflow to run AMIRIS has been developed in Task 4.3, which allows to run all scenarios and considered snapshot years, as well as to calculate metrics concerning cost recovery or other market indicators, such as power prices or dispatch information per generation source.

To study the impact of a growing flexible demand, variants of the original GENeSYS-MOD scenarios were introduced. A baseline case very closely resembles the original GENeSYS-MOD scenarios adapted for the use in AMIRIS. Two variants differ in terms of how much flexible demand technologies are in the system, thus touching upon the investment perspective. In the variant Low Flex, the installed capacity of flexible demand technologies is only half of the one in the Baseline. On the contrary, in the variant High Flex, the installed capacity of flexible demand technologies equals to 150% of the one in the Baseline. Table 4.1 summarises the main characteristics of the considered scenario variants for the year 2045 of the scenario NECP Essentials. Note that the variant High Flex shows a higher overall



power demand due to more electric vehicles and heat pumps in the system. On the contrary, the variant Low Flex is characterised by a lower overall power demand.

Table 4.1. Characterisation of scenario variants for the scenario NECP Essentials in 2045.

Technology	Parameter	Low Flex	Baseline	High Flex
Pumped Hydro	Power in GW	4.73	9.45	14.17
	Capacity in GWh	222.95	445.90	668.85
Batteries	Power in GW	3.10	6.20	9.30
	Capacity in GWh	9.30	18.60	27.90
Electric Vehicles	Number in millions	19.99	39.98	59.98
Heat Pumps	Number in millions	7.50	15.00	22.50

4.3.1. Challenges

The representation of competing flexibility options proved as a challenge, since there is no comparable implementation for agent-based models in the literature. There exist some black box approaches (Harder et al., 2025) or assessments of single flexibility options (Liu et al., 2025; Farahani et al., 2023) that neglect the system context. Another challenge were deviations in the scope and characteristics of AMIRIS compared to GENeSYS-MOD. Input data was widely harmonised; however, there are some differences. While GENeSYS-MOD for instance considers CO₂ limitations via constraints, there is no overarching CO₂ limit in AMIRIS. Instead, as in the real world, AMIRIS includes a price for CO₂ emissions. The utilised price here is derived from the dual values (i.e. shadow prices) of the emission constraint in GENeSYS-MOD. For GoRES, a much higher price than for the other scenarios is observable, peaking at above 5,000 €/t while retaining below 1,000 €/t for all other scenarios except NECP Essentials. Also, for the prevalent analyses, AMIRIS was only parameterised for Germany. In addition, AMIRIS requires some parameters to be added compared to system optimisation models, such as GENeSYS-MOD. These are, for instance, parameters that control the business-oriented dispatch strategies, such as the time horizon for which electricity price forecasts are made and distributed to the agents.

4.3.2. Mitigation Measures

The AMIRIS developers found a flexible way to model competing flexibility within an agent-based simulation environment. The agent that markets the flexibility is attributed with some information on how flexibility options have been dispatched in the past. The agent can use this to derive a dispatch multiplier, which is sort of similarity factor for the dispatch. This allows for an assessment of how the own dispatch, and the prognosed dispatch of competitors may impact prices. By considering a specific assessment function, the agent can choose suitable dispatch schedules. Concerning the parameterisation challenges, input data was harmonised to the extent possible. Deviations and limitations are made transparent.

4.4. Results

The prevalent analyses focus on the cost recovery of variable renewable generators and flexibility technologies. First, the outcomes are presented for one exemplary scenario and snapshot year to show the main mechanics. Next, a cross-scenario and cross-year comparison is shown.

4.4.1. Outcomes

To showcase general result tendencies, the scenario NECP Essentials for the snapshot year 2045 are presented first. This combination has been selected as the NECP Essentials scenario, which closely resembles the status of national NECPs, and the year 2045 is when the German government strives to reach climate neutrality.

Figure 4.2 shows the resulting backup generation for the considered cases. The variant High Flex requires for more backup generation due to an overall higher power demand caused by the increase in flexible demand technologies. Also, this variant is characterised by a higher utilisation of the variable renewable electricity generation, and respectively, lower curtailment rates compared to the Baseline and Flow Flex scenarios.

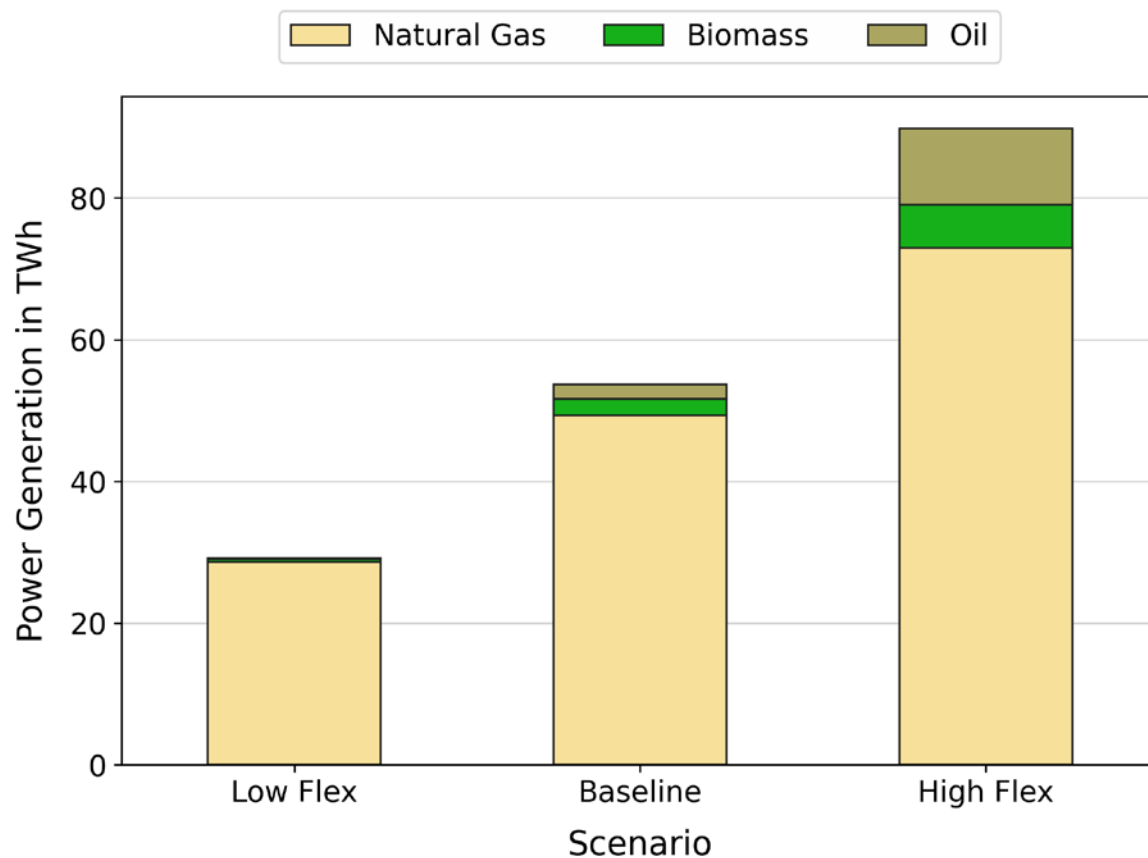


Figure 4.2. Backup power generation in the considered scenario variants for NECP Essentials 2045. Scenarios with a higher flexible demand are characterised by a higher backup power generation.



The cost recovery of renewable generators has been evaluated based on the investment expenses c_{inv} , fixed c_{fix} and variable costs c_{var} those generators face. The cost recovery rate cr_{RES} is defined as

$$cr_{RES} = \frac{TP}{TC} = \frac{\sum_{t=1}^{8760} p_t \cdot g_t}{\sum_{t=1}^{8760} c_{var,t} \cdot g_t + c_{fix} \cdot P + A(c_{inv}, P, i, n)}$$

Hereby, TP denotes the total profit from the day ahead market, TC the total cost, p_t the current power price at hour t , g_t the current power output, P the installed capacity and $A(c_{inv}, P, i, n)$ the annuity of the investment expenses for an interest rate i as well as a lifetime n . Similarly, cost recovery of flexible demand technologies has been evaluated. Therefore, the current power output is replaced by the discharged energy $g_{disc,t}$ at hour t in the numerator and the charged energy $d_{char,t}$ in the denominator of the equation above, leading to:

$$cr_{FLEX} = \frac{TP}{TC} = \frac{\sum_{t=1}^{8760} p_t \cdot g_{disc,t}}{\sum_{t=1}^{8760} c_{var,t} \cdot d_{char,t} + c_{fix} \cdot P + A(c_{inv}, P, i, n)}$$

Interest rates have been taken over from GENeSYS-MOD and assumed to be 5% for all technologies. The lifetime has also been taken from GENeSYS-MOD, and is assumed to be 20 years for batteries, 27 years for wind onshore, 30 years for wind offshore, 35 years for PV and 50 years for pumped-storage.

The values for the respective simulation year have been used for c_{inv} , c_{fix} and c_{var} . This is equal to a situation where the system would have to be rebuilt in the simulation year. This forms a rather optimistic approximation as costs decrease over time.

Figure 4.3 shows the cost recovery for the variable renewable generators. The main finding is that higher levels of a flexible demand contribute to higher cost recovery rates of variable renewable generators. However, in all variants cost recovery rates are well below 100% for all technologies. The cost recovery for wind onshore is the highest among the technologies. Compared to solar photovoltaics, wind onshore suffers less from self-cannibalisation of revenues. Compared to offshore wind, onshore wind shows lower total costs. As the variant High Flex exhibits the highest cost recovery rate, this supports the hypothesis that increased flexible demand can contribute to revenue stabilisation. Yet, for the given scenario and model limitations, cost recovery rates are still insufficient.

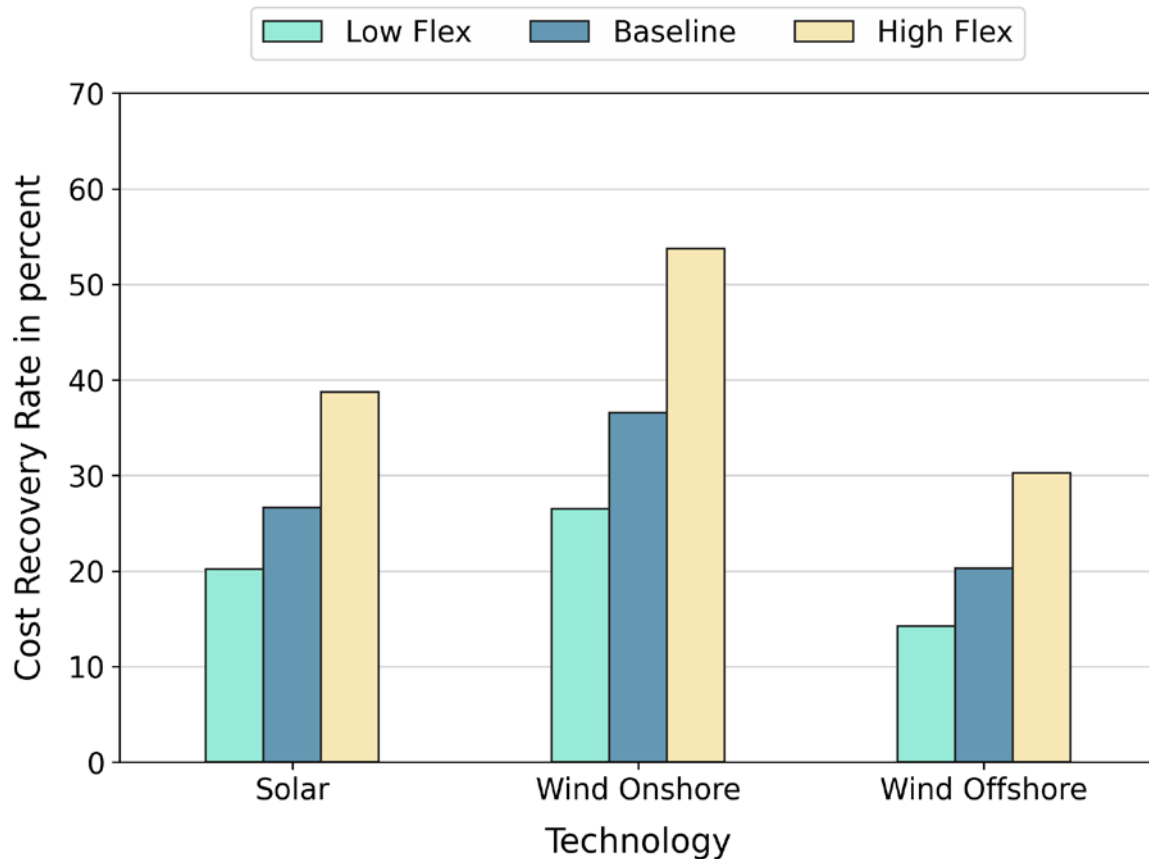


Figure 4.3. Cost recovery (in %) of variable renewable generators in the considered scenario variants. Scenarios with a higher flexible demand show higher cost recovery rates for variable renewable energy sources.

Figure 4.4 shows the cost recovery rates for flexibility technologies. As unidirectional charging electric vehicles and heat pumps cannot directly obtain revenues from wholesale markets, but rather reduce their costs for the power consumption, they are not displayed. The main finding is an opposite trend to the cost recovery of renewables: The higher the flexible demand is, the lower are the cost recovery rates of the flexibility technologies. This can be explained by mutual revenue cannibalisation. However, this general trend does not hold for batteries, as the cost recovery in the High Flex case is even slightly above that of the Baseline.

For all flexibility technologies cost recovery rates are well below 100%. Batteries show the highest cost recovery rates. Compared to pumped storage, they are dispatched more frequent due to their higher roundtrip efficiencies. A cost recovery rate of above zero for bidirectional electric vehicles means that they can earn some money from the feedback to the grid. But, for a higher flexibility demand, these earnings decrease substantially. The variant High Flex shows the lowest cost recovery rate, indicating a clear effect of revenue cannibalisation associated with flexibility.

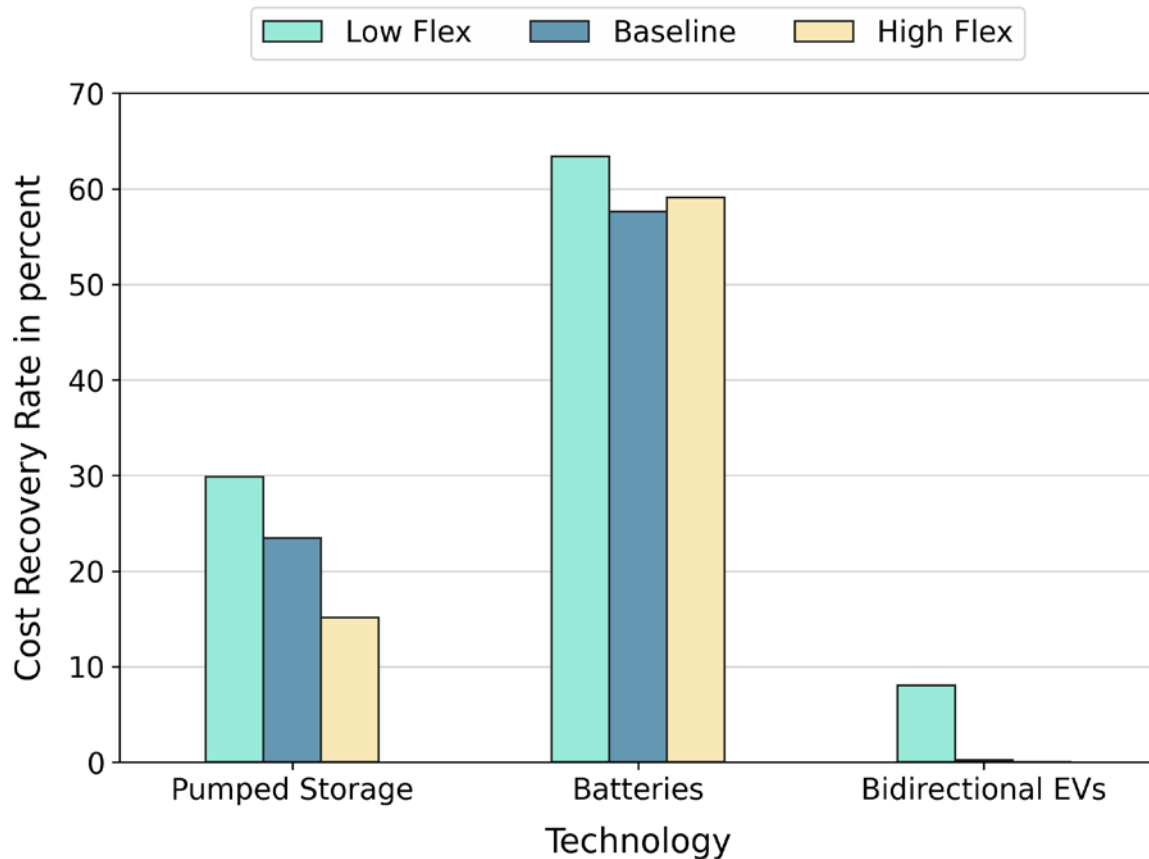


Figure 4.4. Cost recovery (in %) of flexibility technologies in the considered scenario variants. Scenarios with a higher flexible demand show lower cost recovery rates for flexibility technologies.

Cost recovery has also been evaluated across different EU EnVis scenarios. Results for the year 2045 are shown in Figure 4.5 for variable renewable generators, and in Figure 4.6 for flexibility technologies with stark variations in cost recovery among the scenarios and variants.

For the scenario Go RES, cost recovery is higher than for the other scenarios, even exceeding 100% for wind onshore for all variants and solar and wind offshore for the variant HIGH FLEX. The primary reason for this effect can be attributed to the higher CO₂ price for this scenario compared to the other scenarios which results in higher electricity prices. For Batteries, full cost recovery is achieved in the variants Baseline and Low Flex. For all other technologies and cases, cost recovery rates remain below 100%. Quite strong variations of cost recovery can be observed among the scenarios and cases. The cannibalisation of flexibility technologies for higher flexibility demands as well as the supporting effect towards the refinanceability of renewable generators can be observed.

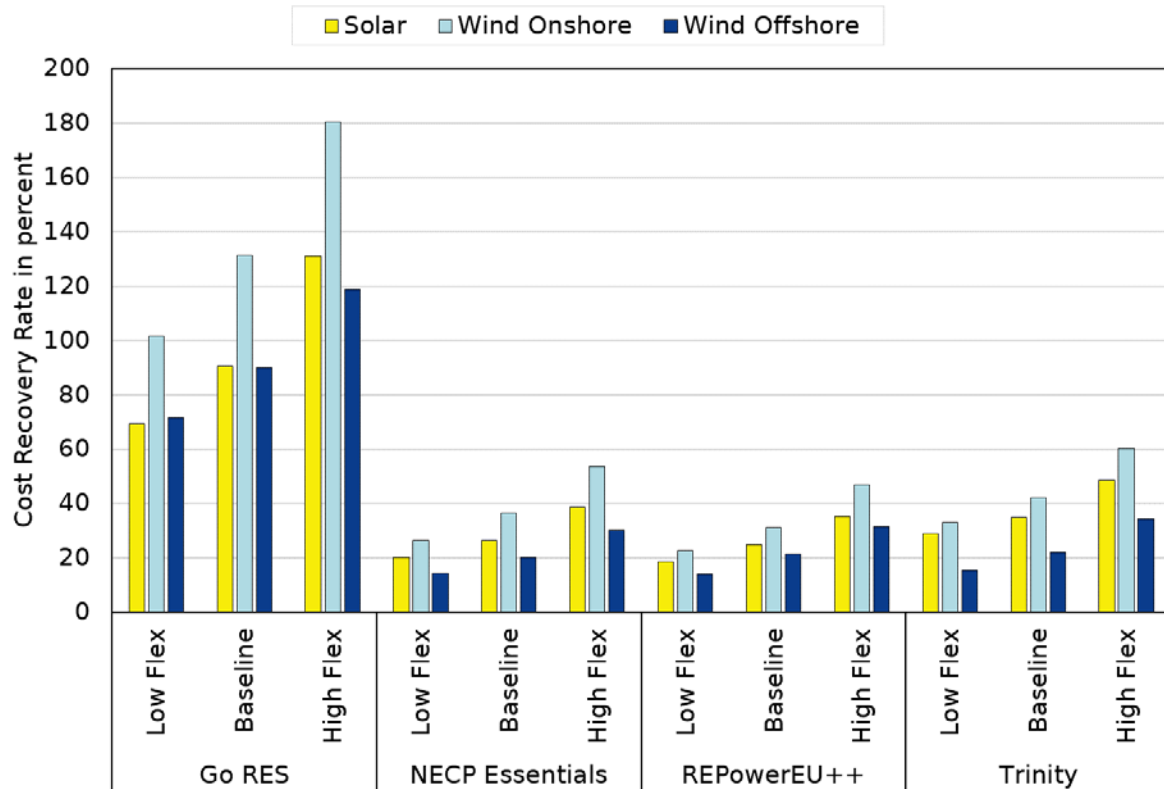


Figure 4.5. Cost recovery (in %) of variable renewable generators across the scenarios for 2045. Go RES shows systematically higher cost recovery due to higher price levels.

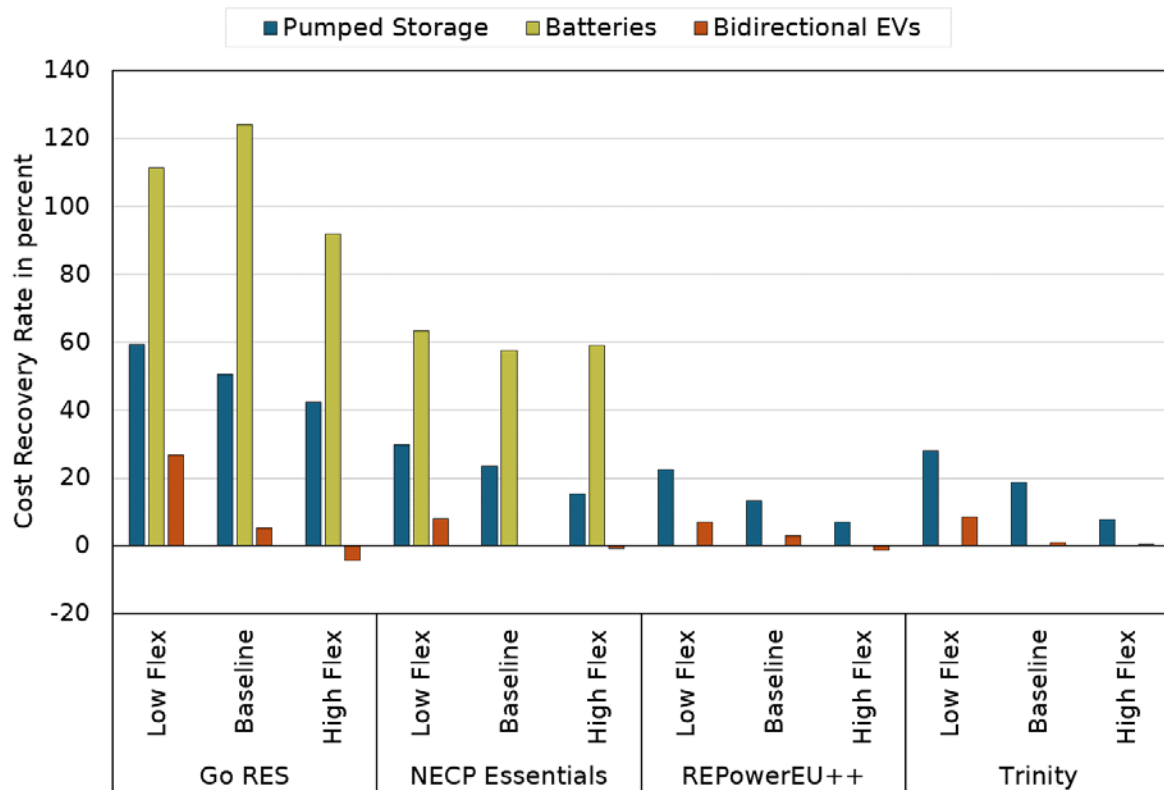


Figure 4.6. Cost recovery (in %) of flexibility technologies across the scenarios for 2045. Generally, higher degrees of flexibility complicate cost recovery.



Figure 4.7 shows the cost recovery for variable renewable generators throughout the years for the variant Baseline. Go RES, in tendency, shows the highest cost recovery rates. The main driver for this is the higher CO₂ price in this scenario, which leads to higher electricity prices. Other minor factors driving electricity prices and thus cost recovery are a higher overall demand level as well as higher backup dispatch for the first and last simulation years, compared to the other scenarios. Cost recovery rates in general reflect the pattern of (average) electricity price levels. Interestingly, in Go RES, solar shows a high cost recovery rate in 2018 which then declines. From 2045 onwards, wind onshore shows a high cost recovery rate. In Go RES, cost recovery rates exceed 100 % for solar and wind onshore in all years. In Trinity, solar can recover its costs, but only for the year 2040. Overall, stark variations among the years and scenarios are observable.

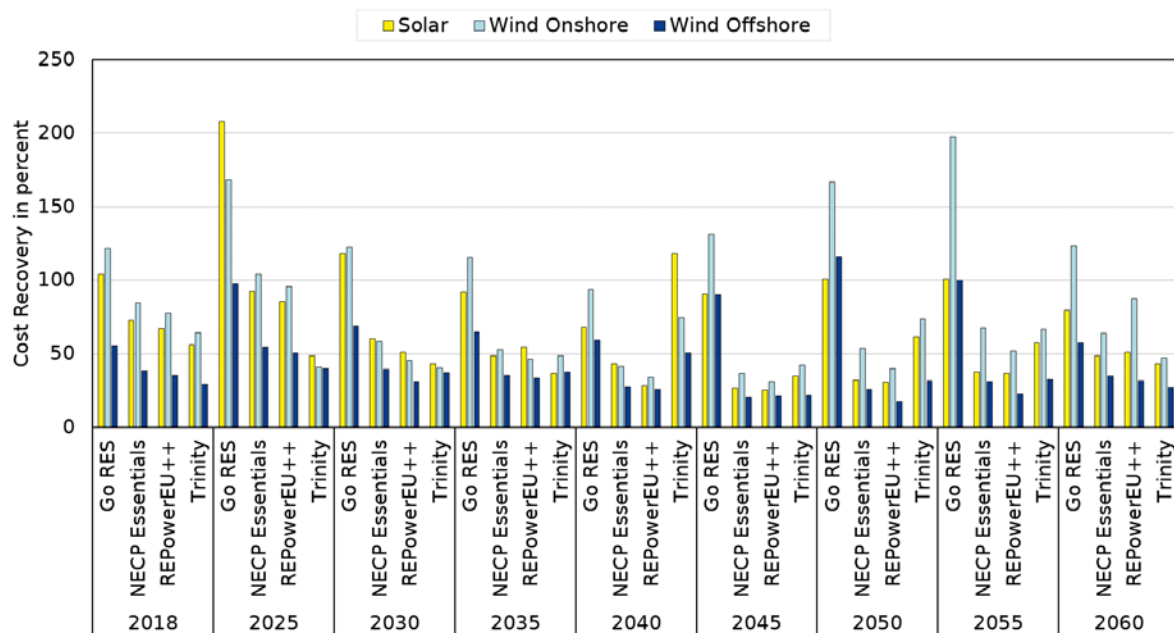


Figure 4.7. Cost recovery of variable renewable generators across the years for variant Baseline. There is a stark variation in cost recovery among the scenarios and years. Go RES consistently shows the highest cost recovery rates.

The cost recovery for flexibility technologies across different years in the EU EnVis-scenarios for the variant Baseline is displayed in Figure 4.8. In 2018, there are no battery capacities as well as bidirectional EVs in the system. Batteries are phased in from 2025 onwards, while notable bidirectional charging capacities can be observed from 2030 onwards. Again, there is a very strong variation across the years. What is especially interesting is that batteries can recover their costs or at least obtain substantial returns in some years, while they phase problems with cost recovery in 2035 and 2040.

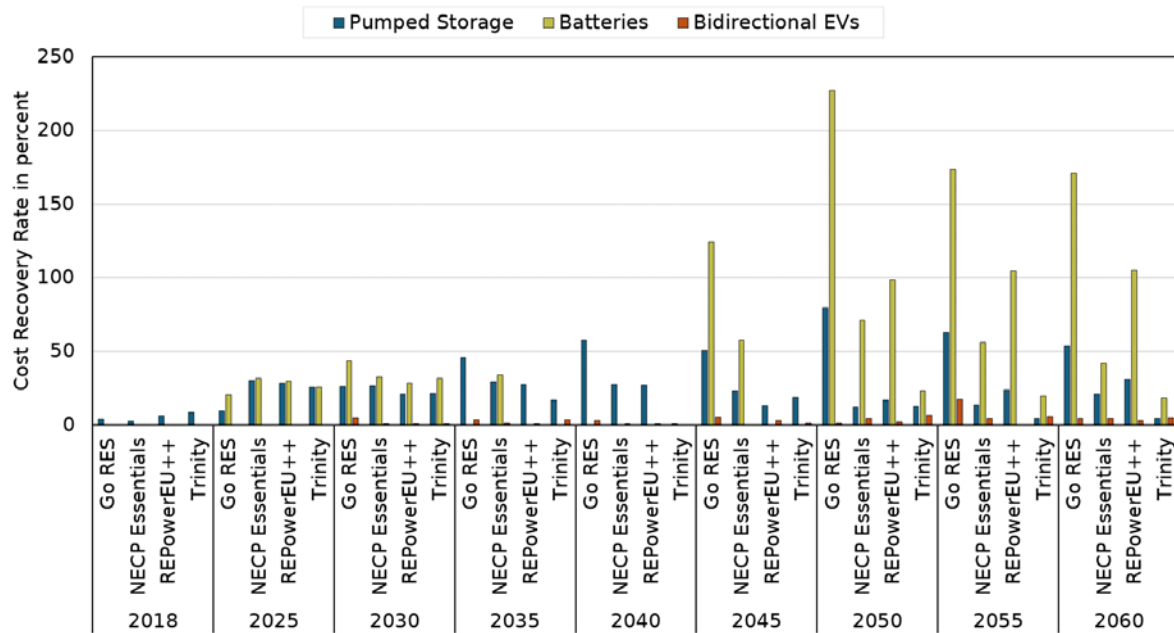


Figure 4.8. Cost recovery of flexibility technologies across the scenarios for 2045. There is a strong variation in cost recovery among the scenarios and variants. Go RES shows systematically higher cost recovery due to higher price levels.

4.4.2. NECPs

For most scenarios and variants, even those with increased flexible demand, cost recovery rates of well below 100% were found for both renewable generators and flexibility technologies. Partly, this can be explained by model limitations that lead to comparatively low electricity price levels. For instance, imports or exports and the flexibility from electrolyzers are not considered. Another explanation is the scenario assumptions, such as rather low fuel prices. However, future fuel prices are highly uncertain and it is not given for granted that they ensure sufficient situations with high electricity prices. Correspondingly, the impact of the high CO₂ prices in the Go RES scenario showcases the importance of analyses on revenue perspectives for renewables and flexibility options in a fully defossilised energy system.

Thus, the observed low price levels raise the question for adequate de-risking or policy support of renewables to ensure that the necessary renewable capacity expansion decisions to meet the NECP target will be made. Similarly, low cost recovery rates for flexibility technologies raise the question how these investments can be de-risked and whether those should be supported. In summary, the observed low “cost recovery rates” raise concerns on whether the German NECP targets can be achieved without proper de-risking or support measures for variable renewable generators and flexibility technologies.

4.4.3. Supplementary Data

The analyses have been conducted using AMIRIS v4.1.0-alpha23 which is just before the release of v4.2.0 and available on GitLab: <https://gitlab.com/dlr-ve/esy/amiris/amiris/-/releases>. For the parameterisation, v4.0 of the EU EnVis-2060 scenarios (scenario versions v1.3.0) has been used: <https://zenodo.org/records/13710869>. The results will be made available under <https://zenodo.org/communities/manOeuvre/> once internal approval processes are completed.

Case study 5: Soft-linking BENOPTex and GENeSYS-MOD

Energy System Models (ESMs) and Integrated Assessment Models (IAMs) are commonly employed for designing policy advice. While IAMs shed light on the interrelation between energy systems, the economy, land use, and climate, ESMs provide comprehensive and context-specific understandings of the technological transition needed to decarbonise the energy system with more temporal and spatial detail. Compared to single region models, Pan-European ESMs offer the advantage of covering a wider geographical scope, spanning multiple European countries, and capturing a more comprehensive view of the interconnectedness and interdependencies within the energy landscape. Doing so enables researchers to accurately model cross-border energy flows, market dynamics, and the EU policy (e.g. the REPowerEU plan), which assists them in studying the competition and synergy between technologies. However, covering a wider geographical scope means dealing with more computational complexity. To mitigate the computation time, researchers often decrease the sectoral coverage, technological, and temporospatial details of these pan-European models. To enrich mentioned dimensions of the selected pan-European model and consider the bio-based economy, we link a regional model with high technological and sectoral granularity (i.e. *BENOPTex*) to GENeSYS-MOD, which governs the energy flow between European countries.

BENOPTex is a perfect foresight model that optimises the allocation of limited bio-based materials and renewable energies to various transformative technology concepts, in order to satisfy the end-use energy/material demands in the transport, heat, and power sectors as well as the chemical industry. Figure 5.1 depicts the connection between BENOPTex and GENeSYS-MOD. The domestic production of biofuels and synthetic fuels can be generated by BENOPTex and used in the GENeSYS-MOD to satisfy the end-use demands.

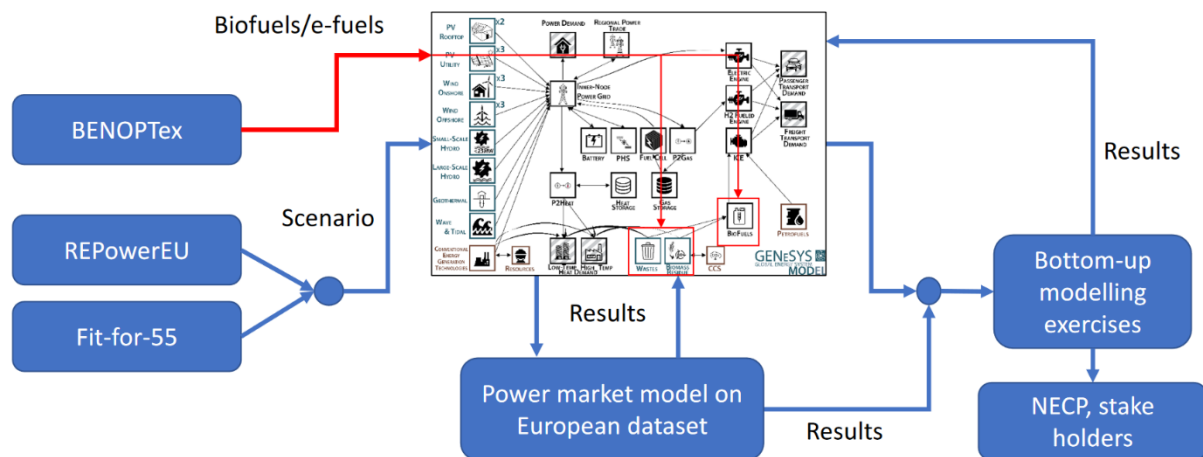


Figure 5.1. Connecting BENOPTex with GENeSYS-MOD.

5.1. Accomplished Tasks

Task 5.1 – Incorporating GENeSYS-MOD outputs in BENOPTex: In this task, we identify and formulate BENOPTex-related parameters within European scenarios. These parameters are translated into mathematical form, resulting in a stochastic optimisation model that is subsequently optimised.

Task 5.2 – Collecting data for selected EU countries to expand BENOPTex: While the main model was still under development, the required data for the selected countries have been acquired. The technical and political frameworks of these countries have been considered to the best of our abilities.



Additionally, the energy exchange between neighbouring countries is taken into account, either implicitly (via scenarios) or explicitly (from/to Germany).

Task 5.3 – Extending the BENOPTex model to include selected countries: The knowledge and data collected in Task 5.2 have been incorporated into the optimisation model developed in Task 5.1. The results have been verified in close collaboration with experts. Various statistical experiments and sensitivity analyses have been conducted in this task to shed light on the impact of political instruments on the future of the bioenergy supply chain. The outputs of this task have been used in Task 5.4.

Tasks 5.4 – 5.5 Publishing outcomes in the scientific journals: This task can be divided into two sections within WP3 and WP5. In the first section, under the umbrella of WP3, most the necessary analyses (from Task 5.3) with the corresponding storylines are collected for publication. The draft of the first manuscript has been finalised during the fourth quarter of the second year (see Gutjahr et al., 2025).

5.2. Planned impact

Our research activities in the ManOEUVRE project hold tremendous promise as they centre on the intricate synchronisation of diverse energy system models at two levels (i.e. regional and pan-European), leading to the attainment of consistent solutions on a continent-wide scale. The developed tools and the generated outcomes through our research are made available to the relevant stakeholders at the end of the project. Policymakers can benefit immensely from the provided insights, as our results will equip them with the means to analyse and anticipate forthcoming events and gauge their ramifications within regional and interregional systems. To better communicate our results, we attend relevant policy forums (e.g. IEA ETSAP, IEA Bioenergy) and academic conferences, such as EEM 2025, EEM 2026, and EUBCE 2025.

While many continent-wide models predominantly concentrate on the power and gas sectors, we take a bold step forward in this case study. We extend our purview to encompass the bioenergy supply chain, a critical yet mostly overlooked facet. By considering not only the power and gas sectors in the GENeSYS-MOD model but also the interplay of the bioenergy supply chain by linking with the BENOPTex model, we enhance the comprehensiveness and relevance of our findings at the European level. Furthermore, BENOPTex accounts for the intricate interplay between future climate scenarios and available lands. This forward-looking approach enables us to provide insights that are attuned to the evolving dynamics of our environment, ensuring the utmost accuracy and applicability of our results for a future resilient system.

5.3. Implementation

First, the output from GENeSYS-MOD is imported into BENOPTex and converted to standard units. For selected scenarios, relevant decision variables are identified for inclusion in BENOPTex. Considering the technological resolution of each model, a permissible range is defined within which the BENOPTex optimal solution may diverge from that of GENeSYS-MOD. This allows for targeted adjustments to GENeSYS-MOD results in the subsequent iteration within WP2. Finally, for the selected sectors and technologies, BENOPTex results are aggregated back into the original format and transferred to GENeSYS-MOD.



5.3.1. Challenges

Due to limitations in defining new technologies within the IAMC format, the detailed pathways of biomass use across different technologies in BENOPTex must be aggregated. Moreover, as the connected models evolve to better capture the interplay between synthetic fuels and bioenergy, they must also incorporate the variability of intermittent renewable resources. This necessitates the development of a stochastic model, which is often computationally demanding.

Expanding the model to additional countries has also proven challenging, as it requires in-depth knowledge of each country's energy system and policy landscape.

5.3.2. Mitigation Measures

Although the IAMC format is less detailed than BENOPTex in representing bioenergy technologies, we provide the necessary data for model expansion in a format that can later be integrated into GENeSYS-MOD.

To capture the intermittency of renewable energy sources for Power-to-X (PtX), we first integrated intermittent renewable technologies into BENOPTex and then used historical weather data to represent their variability. To enhance the model in this regard, we developed a parallelised approach in which each scenario is solved independently using a dedicated solver.

While the model has been successfully extended to Hungary, solving it with a linear programming (LP) solver proved infeasible due to its bi-level structure. To overcome this, the model was further enhanced to incorporate decision variables across multiple levels within an equilibrium solution framework (T. Szabó et al., 2025).

5.4. Results

5.4.1. Outcomes

In this section, we present the results of our case study on the optimal deployment of bioenergy in selected European countries using BENOPTex. Two European countries are selected for this purpose: Germany and Hungary. The Hungarian model has been developed considering national geographical resolution, whereas the German model is detailed to the federal state.

5.4.1.1. Hungarian Case Study

As a first step, we implemented a deterministic model of the Hungarian energy system, focusing on the integration of renewable energy sources (T. Szabó et al., 2025). To this end, the status quo and planned targets for Hungary are collected. The latest Hungarian NECP is studied, and major targets are identified, which are as follows:

- Achieve a share of at least 30% renewable energy sources in gross final energy consumption by 2030.
- Increasing the share of renewable energy in heating and cooling by at least 1 percentage point between 2021 and 2025 and by at least 1.3 percentage point per year between 2026 and 2030.
- Increase the renewable energy share in DH on average by 2.2 percentage points per year until 2030.

- Reducing the share of natural gas to 50% by 2030 in DH, by increasing the share of municipal solid waste and waste heat technologies.

These regulations were modelled endogenously and solved using an iterative optimisation algorithm. The results indicate that the targets outlined in the NECP of Hungary can be improved, and a cost-optimal solution can assist in achieving these targets by utilising bioenergy more efficiently. Figure 5.2 (a) depicts that the GHG emissions of Hungary's energy sector will decrease from an initial value of approximately 46.7 Mt in 2019 to less than 2 Mt in 2050, thanks to the expansion of nuclear and renewable energy in various sectors. The blue trend denoting a scenario without CO₂-price follows exactly the prescribed by NECP's climate neutral WAM scenario for the energy sector. The green trend, however, denoting the scenario with CO₂-price, shows a substantially higher system capacity to reduce GHG emissions, by reaching to only 3,6 Mt CO₂-eq by 2040 – around 14 Mt CO₂-eq lower than required. The green trend denoting the scenario with CO₂-price shows a substantially higher system capacity to reduce GHG emissions, by reaching to only 3.6 Mt CO₂eq by 2040 – around 14 Mt CO₂eq lower than required. Sensitivity analysis across different CO₂ price levels reveals that even a relatively low CO₂ price can significantly reduce emission trends.

Figure 5.2 (b) depicts the overall NECP renewable energy target of 30% in FEC by 2030, its sectoral sub-targets, and the renewable energy shares. The renewable shares in the scenario without CO₂-price also substantially exceed the NECP target for every sector. The reason for overachieving the 2030 targets is that the distribution of GHG-abatement achieved with higher shares of renewables in 2030 is cheaper since reaching to 2 Mt CO₂eq by 2050 remains an overarching target in 2030 as well.

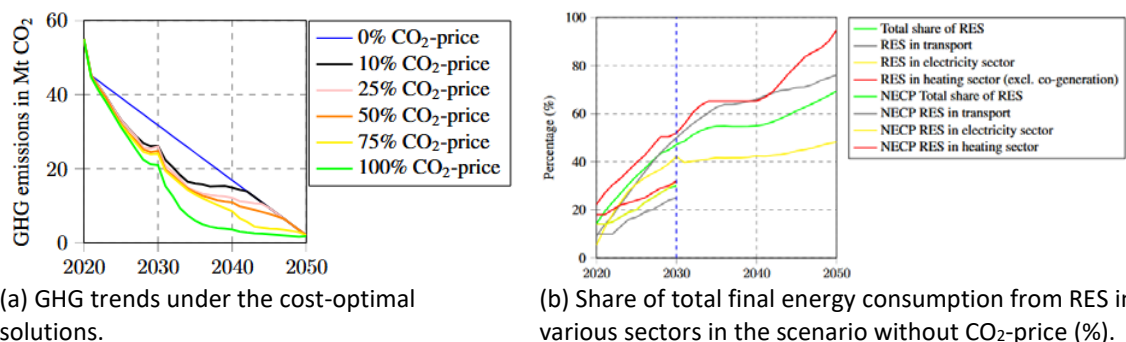


Figure 5.2. Results of modelling Hungarian NECP via the bioenergy optimisation model.

Our findings underscore the important role of geothermal energy (both in heating and power generation), biomass in the heating and cooling sector, and biomethane and second-generation biofuels in the transport sector. The substantial role of bioenergy is evident in the growth of biomass feedstock utilisation in the optimal solution across scenarios, where the consumption of energy crops and residues more than doubles from around 165 PJ in 2020 to around 390 PJ in 2050 (T. Szabó et al., 2025).

5.4.1.2. German Case Study

To endogenously model the generation of renewable electricity from solar and wind, as well as its competition with bioenergy, we extended the deterministic BENOPTex model into a stochastic version (Gutjahr et al., 2025) using 40 years of weather data. Risk sensitivity was incorporated into the objective function through the inclusion of Value-at-Risk (VaR) and Conditional Value-at-Risk (CVaR) measures. The results, in Figure 5.3, show that when solar and wind energy are abundant, the overall system cost is at a minimum, whereas during shortages, flexible bioenergy can support meeting electricity demand, albeit at approximately 10% higher total system cost. Moreover, our findings

suggest that excessive risk sensitivity may drive greater dependence on dispatchable fossil energy, which poses a serious threat to achieving climate targets.

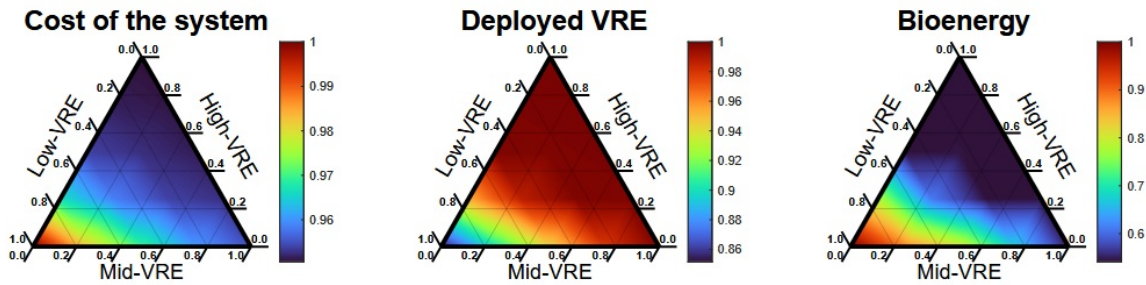


Figure 5.3. Results of risk-neutral stochastic model for German energy system.

As shown in Figure 5.4, under the high availability of variable renewables, the model invests in solar and wind energy more uniformly across states, primarily due to the widespread availability of solar energy. In contrast, under the low availability of VREs, northern states focus more on wind energy and southern states prioritise solar energy, while states located in the central region invest less overall compared to those in the north or south. This results in Bavaria in a capacity multiple times higher than the average of all states under low-VRE scenario in comparison to high-VRE scenario, reflecting patterns similar to the current situation (Gutjahr et al., 2025).

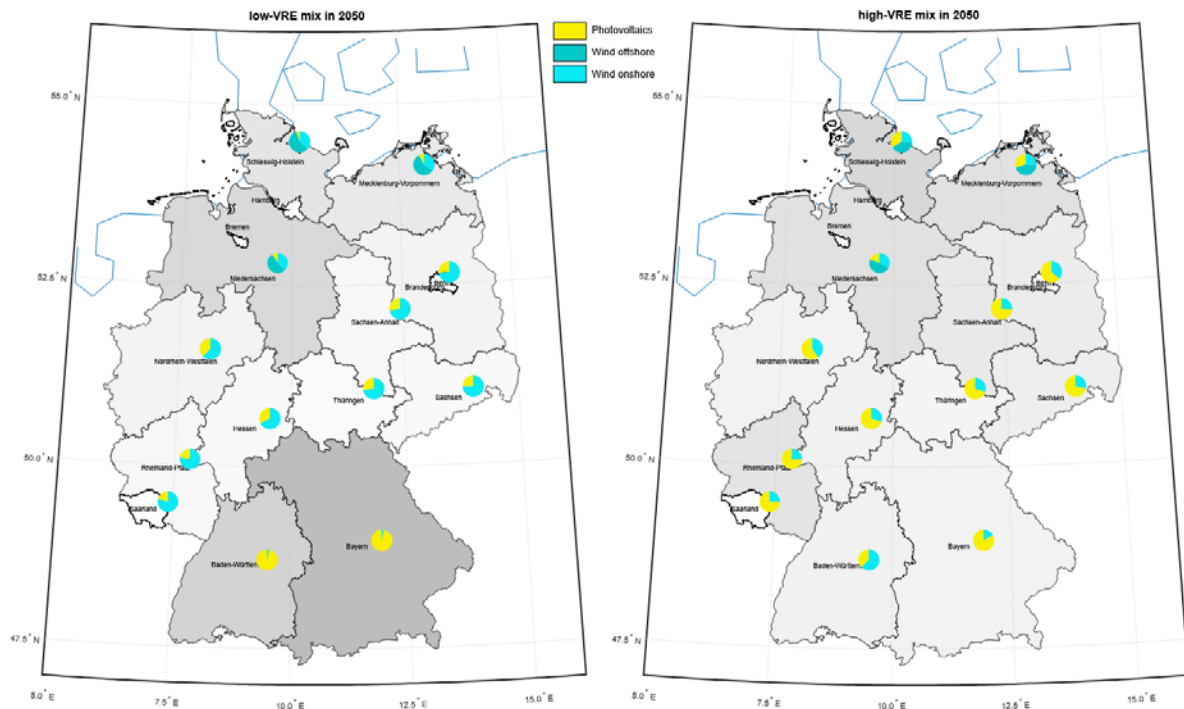
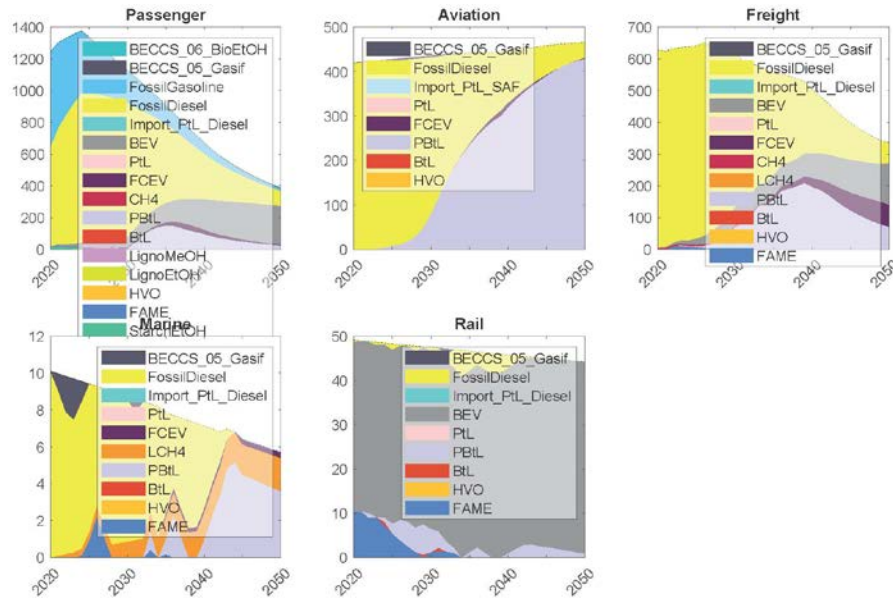


Figure 5.4. A risk-sensitive (i.e. VaR with $\alpha = 99\%$) mixture of VREs (installed capacities in GW) in different German states in 2050.

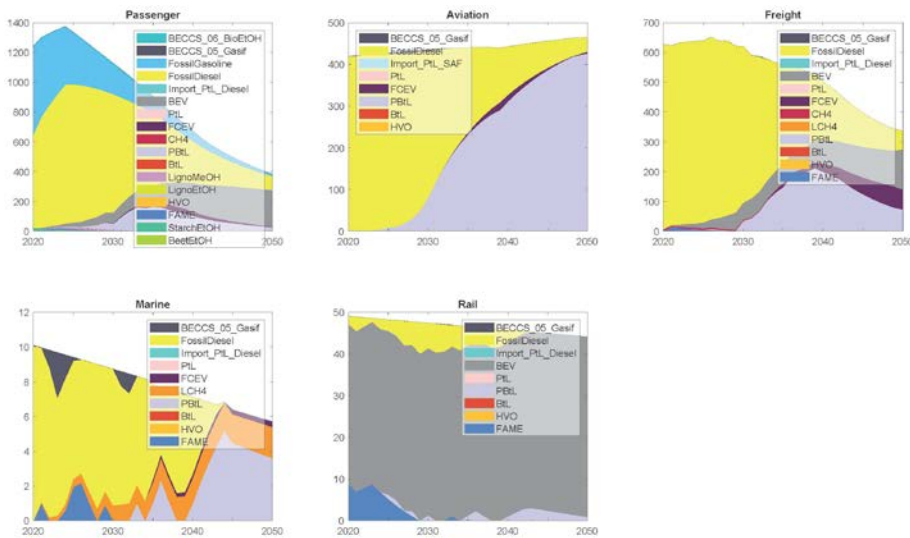
The BENOPTex model is utilised to model selected scenarios that are provided by GENESYS-MOD. Chosen variables are kept feasible within a window based on the level of detail; therefore, the selected BENOPTex technology variables were aggregated to the level of detail provided by GENESYS-MOD. In the evaluation of the results, we present the dominant technologies for the different sectors of the energy system until 2050 in comparison for two analysed scenarios. The size of the windows depends on the scenario. For comparison, the REPowerEU++ and NECP scenarios were selected, utilising GENESYS-MOD data Version 1.2. The following results are broken down by sector.



The analysed transport sector consists of the passenger, the aviation, the freight, the marine and the rail subsector. We identify a decline in energy demand for passenger vehicles, freight, and the marine sector. In 2050, the dominating technologies will be BEV and PBtL. Fossil diesel and gasoline is still used in 2050 in both scenarios but overall, a decline in fossil diesel is shown in Figure 5.5. Besides BEV, an increase in PBtL, especially in the freight and marine sectors, is detected from 2030. Finally, in the marine sector, the usage of liquid methane increases until 2050.



(a): REPowerEU++ Scenario.



(b) NECP Scenario.

Figure 5.5. Technologies in Transport Sector until 2050 in REPowerEU++ Scenario.

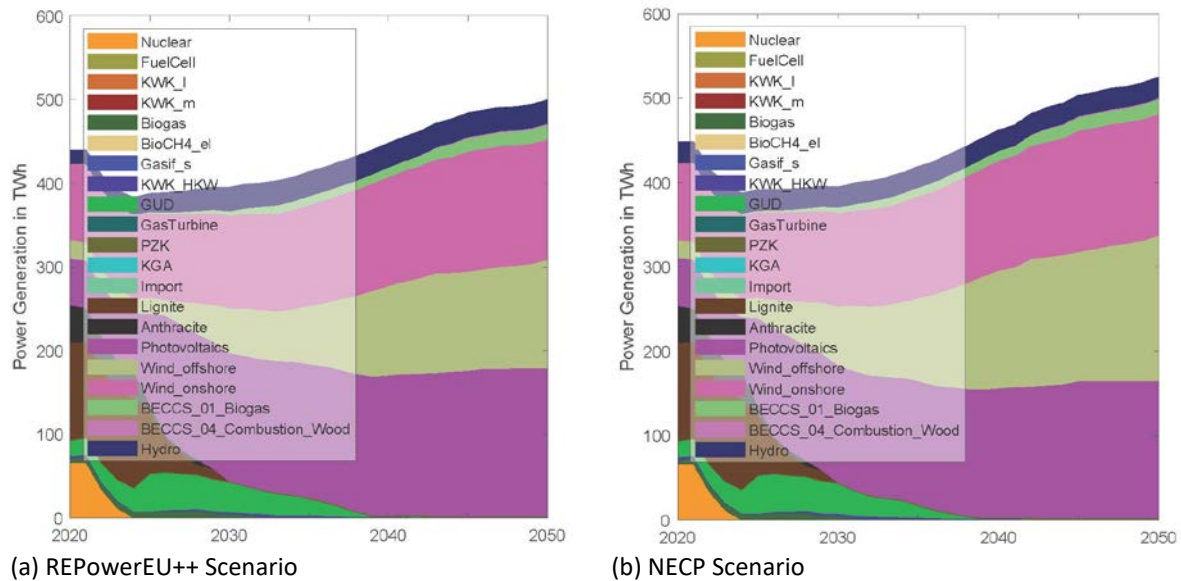
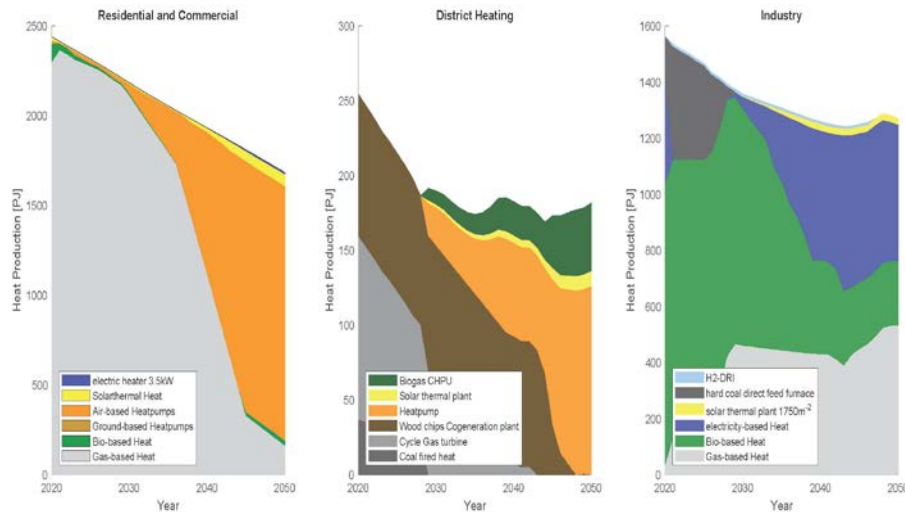


Figure 5.6. Technologies in the power sector until 2050 in REPowerEU++ Scenario.

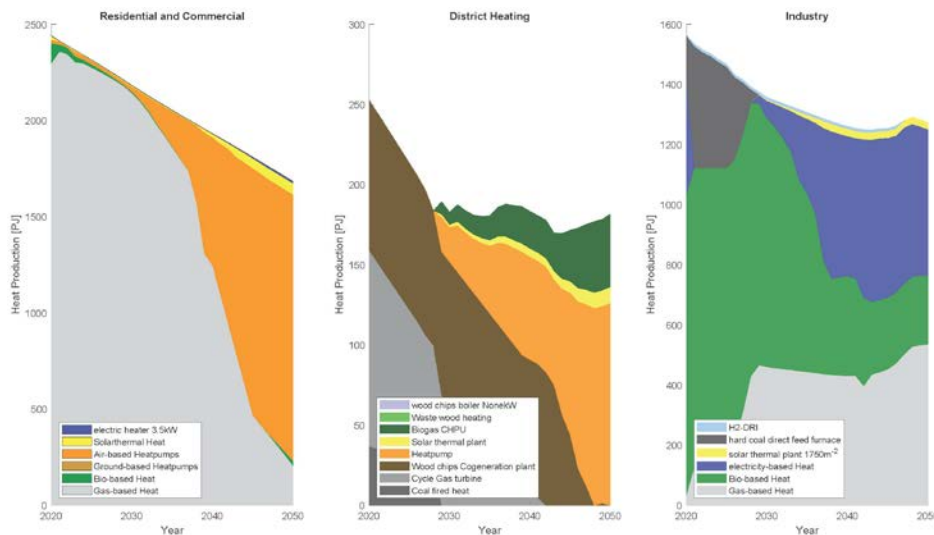
The analysis of the power sector, in Figure 5.6, reveals that under the REPowerEU++ scenario, solar PV will be the dominant technology in 2050. Germany's nuclear phase-out until 2023 is also visible from the figure. Additionally, lignite will be used until 2030 for power production. Figure 5.6(b) shows the electricity production until 2050 under the NECP scenario, and an increase in power generation is visible. To fulfil Germany's NECP targets, the capacities of onshore wind and offshore wind increase until 2050. However, the capacity targets as defined in the NECP will not be reached. BECCS technology will also assist Germany in removing atmospheric CO₂ to compensate for emissions from the hard-to-abate sectors.

For the analysis of the heating sector, three subsectors were identified, and the technologies are aggregated for better visualisation (see Figure 5.7). We analyse heating technologies in the residential and commercial sector, district heating and industry heating. While technologies based on gas decrease in the residential use, as in district heating applications, the industry will rely more on gas in 2050. Bio-based heating technologies are mostly used in the industry subsector. The share of air-based heat pumps will increase for residential and commercial applications and in district heating.

The NECP sets the target for large-scale heat pumps with more than 500kW per year for 2030 to 86TWh, which is not reached in our results. However, as stated in the NECP more than 23.5% of energy in heating and cooling will be generated from renewable sources, the Germany specific goal of 32% is not reached. The goal to implement 500.000 new heat pumps per year is not implemented into the model.



(a) REPowerEU ++ Scenario.



(b) NECP scenario.

Figure 5.7. Technologies in Heating sector until 2050.

In conclusion, it can be stated that the NECP scenario leads to approximately 0.6 % higher total costs compared to the REPowerEU++ scenario.

Comparing the allocation of biomass in different sectors for the two scenarios shows less biomass usage in 2030 under the NECP scenario. In both scenarios, an increase in biomass usage in the transport sector from 2030 to 2050 can be detected. Most biomass is used in the heating sector, and only a small amount for electricity production as indicated by Figures 5.8 (a) and (b).

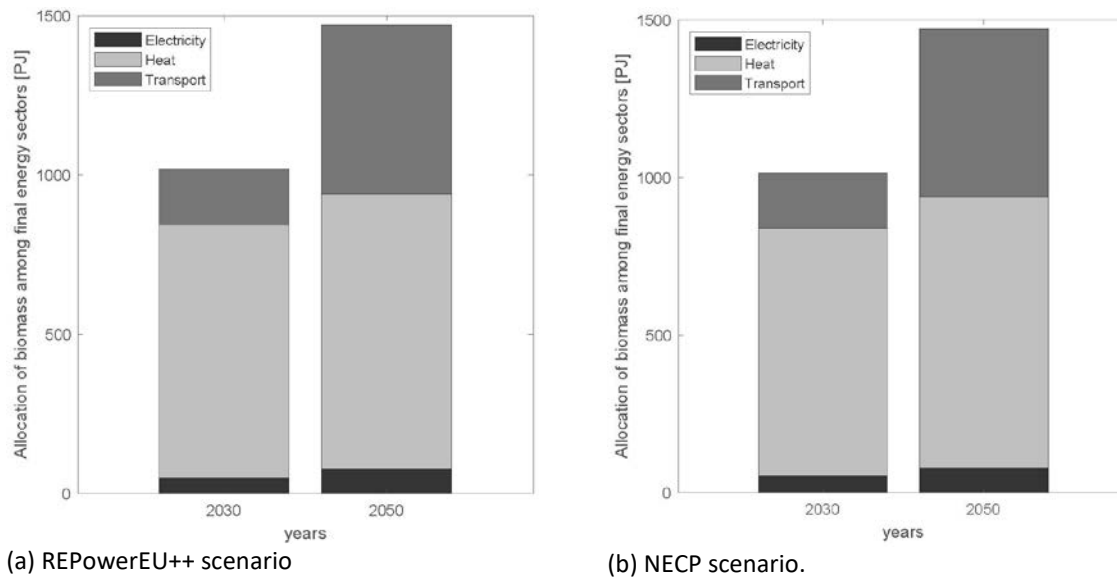


Figure 5.8. Allocation of biomass in different sectors in 2030 and 2050.

5.4.2. NECPs

Germany has set ambitious renewable energy targets. In its NECP, clear goals are outlined for solar (215 GW), onshore wind (115 GW), and offshore wind (30 GW) capacity by 2030. However, the plan does not specify targets for other renewable sources and emphasises that electricity generation from biomass and hydropower is not expected to increase. This means 600 TWh electricity generation from renewables in 2030, accounting for 80% of gross electricity consumption of 750 TWh.

For the heating and cooling sector, the share of renewables must be at least 23.5% by 2030; however, Germany is aiming for an overall share of 32%.

Table 5.1. Final energy demand by sector in Germany

Final Energy Demand in PJ (2030)	NECP (2030)	NECP Essential (v1.2)
Heating and Cooling	5040	4144
Industry	1872	1465
Trade, commerce and households	2520	2952
Transport	2120	1852
Total	11552	10414

5.4.3. Supplementary Data

The BENOPTex output in IAMC format, based on the GENesYS-MOD input variables from EU EnVis-2060 v1.2 for all four scenarios, is available in the following public GitLab repository:

- BENOPTex-GENesYS-MOD: <https://git.ufz.de/gutjahr/benoptex-genesys-mod-data>

The data in the aforementioned GitLab repository may be updated iteratively through soft-coupling between BENOPTex and GENesYS-MOD, as planned.



The developed RAG system as well as CADNN system can be found in the GitLab link of Forootani et al. (2025). Some papers linked to these datasets are under review in various journals and are subject to change.

- RAG System: <https://github.com/ElsevierSoftwareX/SOFTX-D-25-00122>
- CADNN: https://github.com/Ali-Forootani/neural_wind_model
- RE-LLM: <https://doi.org/10.5281/zenodo.17311775> (under review)

Additional implementations and data can be found in the repositories listed below.

- HU-BENOPT: <https://git.ufz.de/esmaeili/hu-benopt> (under review)
- Output of Stochastic BENOPTex: <https://git.ufz.de/esmaeili/sto-benoptex.git> (under review)

Case study 6: Integrating electricity and gas network supported by energy storage and power conversion processes

ESMs are indispensable for exploring pathways towards deep decarbonisation, particularly when analysing the coupling of electricity and gas infrastructures with emerging hydrogen technologies. While pan-European models, such as GENeSYS-MOD-Europe, provide an integrated view of cross-border energy flows, market interactions, and policy impacts, their spatial and technological granularity is often limited by computational complexity. National-level extensions, such as *GENeSYS-MOD-Turkey*, address this limitation by offering more detailed representations of local technologies, sectoral interlinkages, and region-specific energy strategies.

In CS 6, we focus on Turkey as both a critical consumer and potential supplier of hydrogen within the European energy system. Turkey's strategic position as an energy hub, combined with its domestic renewable potential and recently announced national hydrogen strategy, provides a unique opportunity to examine the role of hydrogen in bridging electricity and gas networks. By incorporating hydrogen storage, electrolysis, and fuel cell technologies into *GENeSYS-MOD-Turkey*, we aim to capture their contribution to system flexibility, seasonal balancing, and sectoral decarbonisation.

The case study investigates scenarios where locally produced hydrogen is stored and subsequently utilised across multiple end-use sectors, including residential heating, transportation, and electric vehicle demand. This integration highlights the dual role of hydrogen: as a vector for decarbonising hard-to-abate sectors and as a balancing mechanism supporting large-scale deployment of variable renewable energy sources. By aligning Turkish and pan-European results, CS 6 not only provides insights into Turkey's domestic energy transition but also its potential role in supplying hydrogen to European markets under REPowerEU and related strategies.

6.1. Accomplished Tasks

Task 6.1 – Incorporating GENeSYS-MOD outputs in GENeSYS-MOD-Turkey: In this task, we identified and formulated *GENeSYS-MOD-Turkey*-specific parameters within the broader European scenarios. These parameters were conserved, resulting in an optimisation framework capable of capturing the interaction between Turkey and the European energy system. This formulation provides the



foundation for integrating hydrogen-related pathways, including electrolysis, storage, and conversion technologies, into the national model.

Subsequent analysis revealed that the hydrogen production potential derived from the original, unmodified Input data did not adequately reflect the realistic conditions and prospective capabilities of Turkey's energy system. In particular, the baseline assumptions appeared to underestimate the country's renewable resource potential and future hydrogen demand pathways. To address this limitation, a targeted modification of selected input parameters was undertaken, followed by a new set of simulation runs. These adjustments led to a noticeable increase in the modeled hydrogen production potential, yielding results that are more consistent with national expectations and strategic objectives.

Task 6.2 – Collecting data for Turkey to be used in GENeSYS-MOD-Turkey: While the national model was under development, we gathered the required datasets for Turkey. This included energy demand projections, renewable energy potentials, and infrastructure data, as well as newly published policy frameworks, such as the *Hydrogen Strategy Paper* and the *National Energy Plan* (NEP). The technical and political contexts of Turkey have been considered to ensure that the model outcomes reflect both domestic transition priorities and Turkey's potential role in European hydrogen supply.

The parameters modified within the INPUTDATA include the Input Activity Ratio, Specified Annual Demand, Total Annual Minimum Capacity, and solar-related time series parameters (TS_PV_Avg, TS_PV_Inf, and TS_PV_Opt). The revised values for these parameters were not arbitrarily assigned; rather, they were derived through careful consultation of relevant official and policy documents. These sources include national energy planning frameworks, such as the Hydrogen Strategy Paper and the National Energy Plan, as well as other authoritative reports on energy demand projections, renewable energy potential, and infrastructure development in Türkiye⁹.

Task 6.3 – Running GENeSYS-MOD-Turkey to produce results: The knowledge and data collected in Task 6.2 have been incorporated into the GENeSYS-MOD-Turkey framework developed in Task 6.1. Initial model runs have been conducted to test the integration of hydrogen technologies across electricity, transport, and residential sectors. These simulations are ongoing, with results highlighting the role of hydrogen as a seasonal storage medium and a decarbonisation vector in hard-to-abate sectors. Sensitivity analyses and scenario comparisons are also being prepared to assess the robustness of the results.

Task 6.4 – Publishing outcomes in the scientific journals: This task can be divided into two components within WP3 and WP5. In the first component, under the umbrella of WP3, analyses from Task 6.3 with their associated storylines will be consolidated for publication in peer-reviewed journals. The draft of the first manuscript is scheduled to be finalised during the fourth quarter of the second year. In the second component, linked to WP5, dissemination and communication activities will continue, with a MSc student preparing further publications under the advisory guidance of the postdoctoral researcher.

6.2. Planned impact

The integration of hydrogen-based storage and conversion systems in the GENeSYS-MOD models is expected to yield significant benefits both locally for Turkey and at the broader European scale. Locally, incorporating hydrogen into Turkey's energy mix will help decarbonise hard-to-abate sectors

⁹ Throughout this case study, the terms "Turkey" and "Türkiye" are used interchangeably, both refereeing to the Republic of Türkiye.



(such as heavy industry, heating, and long-haul transport) by replacing fossil fuels with green hydrogen. This is crucial for meeting Turkey's climate goals (including net-zero emissions by 2053) and reducing dependence on imported natural gas. In scenario analyses, introducing hydrogen (e.g. via power-to-gas and blending) led to substantial reductions in CO₂ emissions and lowered natural gas demand, thereby cutting import dependency. Moreover, using hydrogen as a storage medium enhances flexibility and resilience in the energy system: Surplus renewable electricity can be converted to hydrogen and stored, then converted back to power during peak demand or low renewable periods. This long-term storage capability (far beyond battery timescales) provides seasonal balancing and backup, improving the reliability of a renewable-based grid. It also strengthens energy security by enabling domestic renewable energy to substitute for fossil fuels.

EU-wide, the hydrogen integration in Turkey's model has positive *spillover* effects aligned with European decarbonisation initiatives. The EU's REPowerEU plan, for instance, targets 20 million tonnes of renewable hydrogen by 2030 (10 Mt domestic production and 10 Mt imports) to both decarbonise and diversify Europe's energy supply. Turkey's capacity to produce green hydrogen at scale can contribute to this goal by exporting renewable hydrogen or synthetic methane to European markets, leveraging its abundant solar/wind resources and strategic location. This supports EU efforts to replace natural gas (especially Russian imports) with clean alternatives, enhancing overall system resilience. At the same time, domestic benefits in Turkey (reduced emissions and improved flexibility) complement EU climate objectives – both aim for net-zero emissions around mid-century. In line with REPowerEU and Turkey's own NEP, the project's modelling of hydrogen systems is expected to accelerate electrification and sector coupling. By enabling higher renewable penetration and electrification of end-uses, it addresses goals such as increasing the share of electricity in final energy (to ~25% by 2035) and expanding clean hydrogen capacity. For example, Turkey's NEP calls for deploying 5 GW of electrolysis capacity by 2035 to produce green hydrogen, as a stepping stone to 70 GW by 2053. Integrating hydrogen storage in the model directly contributes to these targets, demonstrating pathways to achieve them. In summary, the planned impact includes faster decarbonisation of multiple sectors, strengthened energy security through hydrogen-based flexibility, and concrete contributions to the REPowerEU strategy and Turkey's NEP objectives (renewables integration, electrolyser deployment, and electrification of demand).

6.3. Implementation

To realise the above vision, a phased implementation approach has been undertaken for Case Study 6. The GENeSYS-MOD-Europe results provide a high-level pathway, which is being downscaled and refined for Turkey using GENeSYS-MOD-Turkey, ensuring consistency between EU-wide trends and national specifics. The implementation steps are summarised as follows:

- **Incorporating EU Scenario Outputs:** First, outputs from the European model (GENeSYS-MOD for Europe) were integrated as boundary conditions and benchmarks for the Turkish model. This included using European decarbonisation scenarios (with hydrogen deployment) to inform Turkey's model inputs. Key parameters such as carbon prices, fuel import prices, and overall hydrogen demand/supply levels from the EU scenario were mapped onto the Turkey model to ensure alignment with the broader EU pathway.
- **Collecting National Data and Model Extension:** Next, the team gathered up-to-date national data and adapted the model to Turkey's context. This involved assembling detailed Turkish energy data: demand projections by sector, renewable energy potentials, technology costs, and policy targets (from sources like Turkey's NEP and Climate Strategy). The GENeSYS-MOD-

Turkey model was then extended with new modules to represent hydrogen pathways at a finer resolution. For instance, local electrolysis, hydrogen storage, and fuel cell technologies were added or parameterised based on Turkey-specific conditions. Infrastructure for hydrogen – such as potential pipeline transport and storage facilities – was approximated within the model’s framework. Throughout this phase, care was taken to validate that imported EU-level assumptions (from the first step) were consistent with Turkey’s data (e.g. adjusting Europe-wide parameters to match Turkey’s demand scale and resource availability).

- **Running Local Simulations:** With the data and model updates in place, scenario simulations for Turkey are being executed. The model is currently solving for least-cost energy system pathways for Turkey through 2050, now with hydrogen storage and conversion options enabled. These runs explore multiple scenarios (e.g. varying hydrogen demand in transport, different electrolyser cost trajectories, and policy constraints like emission caps aligned with net-zero 2053). Finally, the outcomes are fed into analysis of how hydrogen can optimally be deployed in Turkey’s energy mix under different conditions.

6.3.1. Challenges

Implementing this integrated modelling approach has presented several **technical and logistical challenges**:

- **Data Integration and Consistency:** One challenge is harmonising data and assumptions between the EU-wide model and the Turkish model. The European scenario operates at an aggregated level, so downscaling its results to disaggregated Turkish model (and combining them with detailed local data) requires careful calibration. Ensuring consistency in input parameters (e.g. technology costs, efficiencies, and demand projections) is non-trivial – discrepancies could lead to misaligned outcomes.
- **Adapting EU-Level Constraints to Turkish Context:** The EU scenario provides overarching targets and limits (e.g. EU-wide CO₂ budgets, hydrogen import/export targets, renewable deployment goals), which are not directly applicable at the national level without adjustments. A challenge has been translating these high-level constraints into the Turkey model. For example, if the European model assumed a certain availability of hydrogen imports or a uniform carbon price, the Turkish model must adapt this to local policy context (Turkey’s own emissions targets, trade possibilities, etc.).
- **Multi-Sector Coupling and Model Complexity:** Incorporating hydrogen affects multiple sectors (power, transport, industry, buildings), which increases the complexity of the model. Capturing sector coupling – for example, linking surplus renewable electricity in the power sector to hydrogen production for transport or heating – means the model must handle new interactions and possibly finer time resolution. This multi-sector integration is computationally demanding and can lead to larger solution spaces for the optimisation. Balancing detail and tractability are a challenge: Too much detail could make the model intractable, while too little could miss important dynamics of hydrogen use across sectors.
- **Harmonising National Targets with Regional Data:** While national data for Turkey’s electricity system are well-established, hydrogen-specific datasets—such as techno-economic parameters for domestic production, storage, and transport—remain scarce. Aligning these with policy frameworks, including the Hydrogen Strategy Paper, NEP, and Climate Change Mitigation Strategy, requires careful harmonisation.



6.3.2. Mitigation Measures

Several measures have been implemented to address the above challenges and ensure a robust modelling framework:

- **Parameter Validation and Harmonisation:** To tackle data integration issues, a thorough validation of input parameters was conducted. We cross-checked European model outputs with Turkish statistics and adjusted inputs accordingly. For instance, if the EU model projected a certain hydrogen demand in Turkey by 2030, we compared it with Turkey's own plans and modified demand profiles to avoid unrealistic gaps. Additionally, the team performed test runs and sensitivity analyses to ensure that the integrated dataset yields stable and credible results for Turkey (e.g. checking that energy balances and emissions in the base year match known values).
- **Model Enhancements with Modular Design:** The GENeSYS-MOD framework's open, modular structure has been used to incorporate hydrogen-related technologies as plug-in modules. The team added new functionality for electrolyzers, hydrogen storage, and fuel cells in a stepwise manner, verifying each addition against simple test scenarios. By designing these components modularly, we maintained flexibility to activate or deactivate parts of the hydrogen supply chain as needed. For instance, a module for **local electrolysis and storage** was developed (reflecting a PV–electrolyser–H₂–fuel cell system) and integrated into GENeSYS-MOD-Turkey. This modular approach mitigates complexity: We can isolate the hydrogen sub-model for debugging, and ensure it interfaces correctly with the power, transport, and gas sectors. It also allows adapting EU-level hydrogen constraints (like blending limits or import availability) by toggling parameters in the module without overhauling the whole model.
- **Use of Open-Source Tools and Data Standards:** The project leverages open-source modelling tools and **harmonised data sets** to ease integration. GENeSYS-MOD itself is open-source, which allowed the team to modify the code for new hydrogen functionality without proprietary barriers.

Data gaps for hydrogen in Turkey are mitigated through triangulation of sources: published government strategies (Hydrogen Strategy Paper, NEP, Climate Change Mitigation Strategy), and international technology cost databases.

To deal with uncertainties around Turkey's export role, we construct multiple scenarios with differing assumptions about infrastructure investments and policy harmonisation with Europe. This approach enabled us to bound the potential range of Turkey's contribution to the European hydrogen system, while remaining consistent with both national NECPs and EU decarbonisation pathways.

6.4. Results

The results from the GENeSYS-MOD-Turkey simulations with hydrogen integration are promising, illustrating how hydrogen can bolster Turkey's energy transition while interacting with the broader European system. Overall, the model suggests that introducing hydrogen technologies leads to a more flexible, low-carbon energy system by 2050.

Hydrogen emerges as a key energy carrier that connects sectors: It enables excess renewable power to be stored and later used across electricity, transport, and heating applications, thereby smoothing out intermittency and aligning energy supply with demand patterns. The presence of hydrogen-based



storage improves the resilience of the system – Turkey can maintain energy supply during peak demand or low renewable periods by tapping into hydrogen reserves, reducing the risk of outages or reliance on emergency fossil backup. Importantly, the results indicate these benefits can be achieved while pursuing Turkey’s and Europe’s long-term climate targets.

The integrated scenario meets stringent decarbonisation goals (consistent with net-zero emissions by 2053 for Turkey) and even allows Turkey to contribute to EU climate objectives by exporting clean energy in the form of hydrogen or derived fuels. In the following subsections, we will detail the outcomes of the case study, discuss how they align with policy targets, and outline the supplementary data that will accompany this report.

6.4.1. Outcomes

The model outcomes reveal several qualitative trends about hydrogen’s role, as well as indicative quantitative impacts on Turkey’s energy mix:

- **Hydrogen Uptake in Transport and Residential Sectors:** The simulations show hydrogen being substantially utilised in transportation, particularly for modes less suited to direct electrification. By 2040–2050, a notable fraction of Turkey’s heavy-duty transport energy is supplied by hydrogen (fuel-cell trucks, buses, and possibly trains), reducing diesel use and cutting emissions. Lighter vehicles are largely electric, but hydrogen fuel-cell vehicles complement battery EVs for long-range needs. In the residential and commercial sectors, the model anticipates hydrogen playing a strategic role. Rather than widespread direct hydrogen heating, the optimal pathway is to blend hydrogen into existing natural gas networks for heating and cooking, especially post-2040, to decarbonise those end-uses. By 2050, the hydrogen blending rate in gas could reach the technical limits (on the order of 15–20% by energy, as a placeholder), which abates a corresponding share of emissions from buildings. Additionally, small-scale fuel cells appear in some scenarios for combined heat and power in buildings or distributed generation, supporting residential loads and providing backup power using hydrogen – these further underlines hydrogen’s versatility alongside electrification.
- **Seasonal Balancing and Energy Storage:** A critical outcome is the utilisation of hydrogen for seasonal energy storage. The model’s least-cost solution leverages Turkey’s summer surplus of solar and wind generation to produce hydrogen via electrolysis, which is stored for later use. During winter months or prolonged low-renewable periods, this stored hydrogen is converted back to electricity (through fuel cells) to meet demand peaks. This pattern confirms the expected role of hydrogen as a seasonal battery for the energy system. Quantitatively, the storage capacity (hydrogen tanks or underground caverns) in 2050 is on the order of several TWh of energy, enabling a significant shift of energy from high-output periods to months with deficits. The presence of this storage smooths out the renewable supply curve and reduces curtailment of solar/wind – the model results show a reduction in renewable curtailment by a substantial margin thanks to hydrogen conversion. Moreover, the resilience benefit is evident: even in stress-test simulations (e.g. Dunkelflaute), the hydrogen buffer ensures electricity supply adequacy and reduces reliance on imported fuels or costly peaking plants.
- **Integration with PV/Wind Generation:** The hydrogen pathway significantly enhances the integration of renewable energy in Turkey. By providing an outlet for excess generation, it allows the model to install more solar and wind capacity without the usual constraints of curtailment or grid instability. In scenarios without hydrogen, renewable expansion was limited by the need for balance, but with hydrogen, the 2050 renewable installed capacity is



higher. The hourly dispatch profiles from the model show that midday solar peaks, which would overshoot demand, are absorbed by flexible electrolyzers ramping up to convert electricity to hydrogen. Wind generation at night or in windy seasons is similarly utilised to produce hydrogen when it exceeds immediate demand. This flexible load from electrolysis effectively acts as a grid-balancing resource, consuming power when prices are low or when the grid needs to shed load. Conversely, during peak demand or low renewable periods, the stored hydrogen is used to generate power, feeding electricity back into the grid. This two-way interaction (power-to-hydrogen and hydrogen-to-power) improves overall system efficiency and economics: It reduces the curtailment losses and provides a form of arbitrage that flattens the demand-supply mismatch. The model results thus expect higher renewable penetration – by 2050, renewables could contribute over 60% of Turkey’s total final energy consumption (up from ~20% today, based on our calculations), facilitated by hydrogen storage and conversion. In summary, the outcomes highlight hydrogen as a linchpin for integrating renewables and decarbonising challenging sectors, with tangible benefits in terms of emissions reduced, fossil fuel imports avoided, and system flexibility gained.

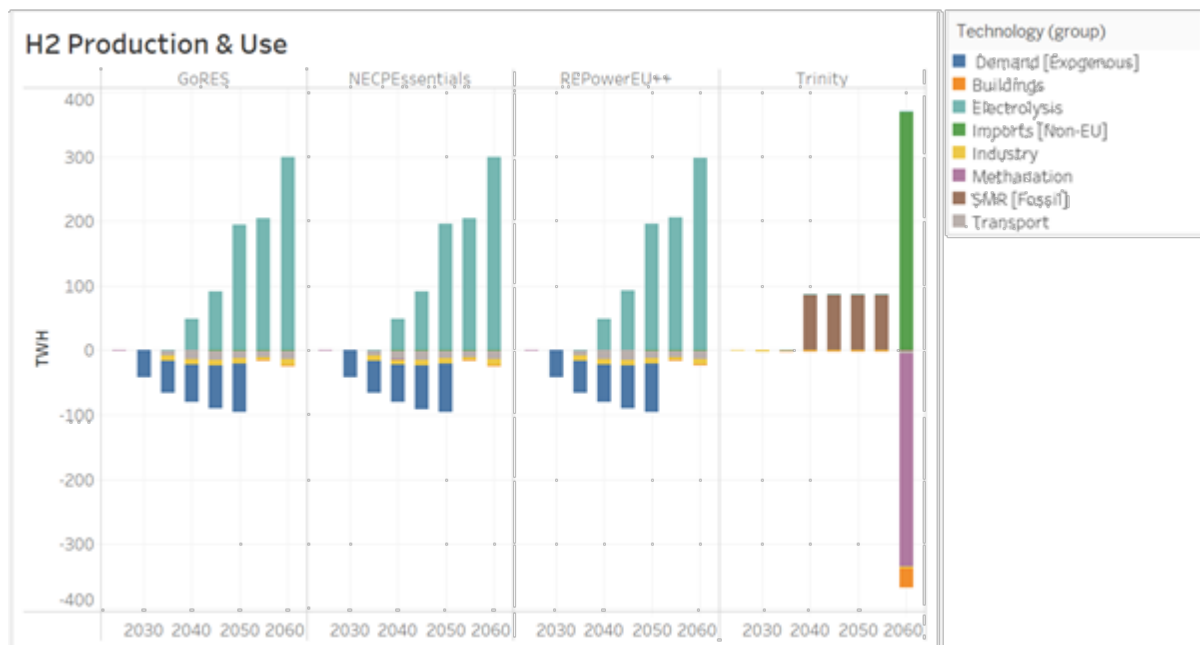


Figure 6.1. Hydrogen Production and Sectoral Use (TWh).

The Figure 6.1 illustrates the evolution of hydrogen (H₂) production and consumption in Türkiye from 2030 to 2060 under four scenarios—GoRES, NECPEssentials, REPowerEU++, and Trinity—with values expressed in TWh. Hydrogen supply is represented by positive values, including production from electrolysis, SMR, and imports, while hydrogen demand is shown as negative values across end-use sectors such as industry, transport, and buildings. Across the GoRES, NECPEssentials, and REPowerEU++ scenarios, a clear and consistent transition toward electrolysis-based hydrogen production is observed. In these pathways, electrolysis emerges as the dominant production technology, expanding steadily from approximately 50 TWh in 2030 to around 300 TWh by 2060. This growth reflects a strong reliance on renewable electricity and indicates a structurally similar decarbonisation trajectory across the three scenarios. At the same time, hydrogen demand increases gradually, primarily driven by industrial applications, with smaller contributions from transport and buildings. By 2060, total hydrogen demand approaches roughly 100 TWh in these scenarios.



Importantly, the scale of electrolysis-based production closely matches domestic demand, suggesting that Türkiye achieves a largely self-sufficient hydrogen system with minimal dependence on imports or fossil-based production.

In contrast, the Trinity scenario presents a markedly different system configuration, characterised by a strong reliance on external hydrogen supply and a more complex sectoral integration. Hydrogen imports increase significantly over time, reaching approximately 380 TWh by 2060, which substantially exceeds the levels of domestic electrolysis observed in the other scenarios. This indicates a strategic shift toward an import-dependent hydrogen system. Additionally, fossil-based hydrogen production via SMR remains present at around 80–90 TWh from 2040 onwards, implying a slower or incomplete transition away from carbon-intensive production methods. A notable feature of the Trinity scenario is the large-scale role of methanation, which accounts for a substantial share of hydrogen consumption, reaching nearly -350 TWh by 2060. This reflects an increased use of hydrogen for synthetic fuel production and power-to-gas applications, pointing to deeper sector coupling between the electricity, gas, and fuel systems. Unlike the other scenarios, where production and demand remain relatively balanced, the Trinity pathway exhibits a structural decoupling between supply and consumption, driven by high import dependence and conversion processes.

Overall, the comparison highlights two distinct transition pathways for Türkiye's hydrogen system. The GoRES, NECP Essentials, and REPowerEU++ scenarios align with a renewable-based, domestically balanced hydrogen economy, consistent with broader European decarbonisation objectives and emphasising energy self-sufficiency. In contrast, the Trinity scenario reflects a globally integrated approach, where hydrogen trade, fossil-based production persistence, and synthetic fuel generation play a central role. These differences have important implications for Türkiye's position within the European energy system. In the first group of scenarios, Türkiye could potentially act as a stable, self-reliant producer with limited export opportunities, supporting regional decarbonisation. In the Trinity scenario, however, Türkiye becomes a major hydrogen importer, increasing its exposure to international supply dynamics and reinforcing the importance of cross-border infrastructure, market integration, and energy security considerations within the broader EU context.

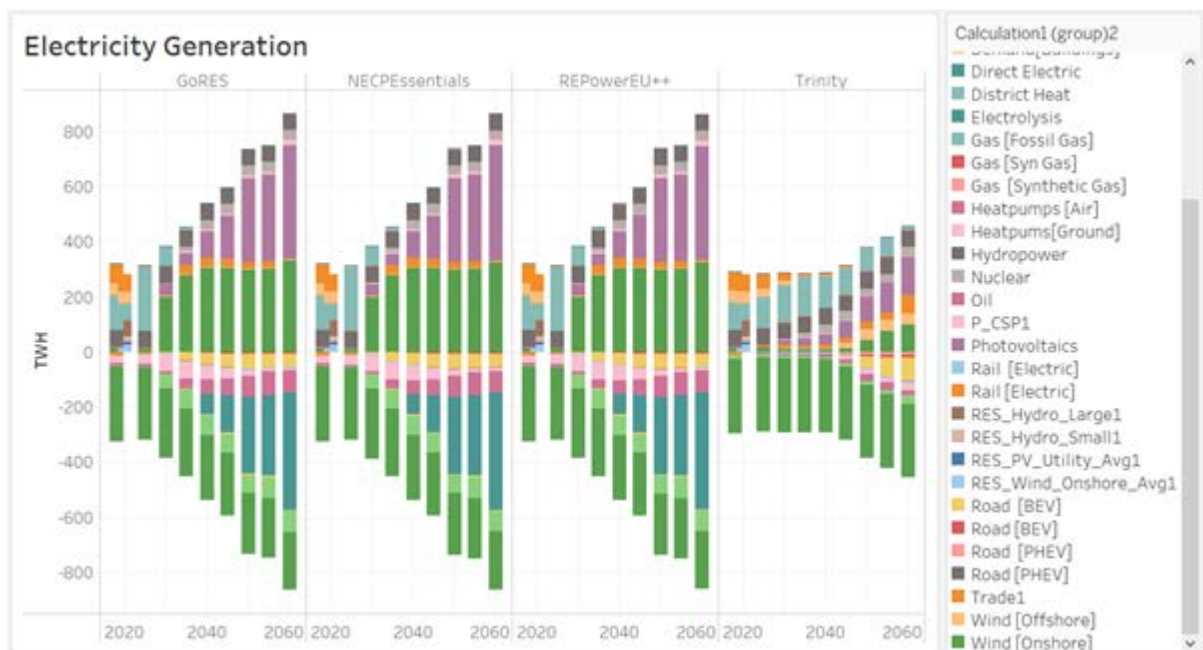


Figure 6.2. Electricity Generation and Demand Balance (TWh).



Figure 6.2 presents the evolution of electricity generation in Türkiye from 2020 to 2060 under four scenarios—GoRES, NECP Essentials, REPowerEU++, and Trinity—measured in TWh and disaggregated by generation technologies alongside sectoral electricity demand. Positive values represent electricity generation by different sources, while negative values reflect electricity consumption across sectors such as industry, transport, buildings, and exogenous demand. Across the GoRES, NECP Essentials, and REPowerEU++ scenarios, a clear and consistent upward trajectory in total electricity generation is observed, increasing from approximately 300–350 TWh in 2020 to nearly 850–900 TWh by 2060. This substantial growth is primarily driven by the rapid expansion of renewable energy sources, particularly PV and wind, which progressively dominate the generation mix. Hydropower and nuclear energy provide additional stable contributions, while fossil-based generation, including coal and natural gas, declines over time, indicating a structural shift toward a low-carbon electricity system. The increasing role of electrification is also evident on the demand side, where electricity consumption grows significantly, especially in industry and direct electrification applications, reflecting broader sector coupling and decarbonisation efforts.

A notable feature in these three scenarios is the strong increase in electricity demand associated with electrolysis, which becomes a major driver of system expansion by mid-century. The integration of hydrogen production into the power system leads to a substantial rise in electricity consumption, particularly after 2040, contributing to the steep growth in total generation capacity. Despite this increasing demand, the system remains relatively balanced, with renewable generation scaling sufficiently to meet both conventional electricity needs and emerging hydrogen-related loads. Technologies such as heat pumps and district heating further reinforce electrification trends, especially in the buildings sector, while transport electrification also contributes to incremental demand growth.

In contrast, the Trinity scenario exhibits a noticeably different evolution of the electricity system. Total electricity generation remains significantly lower compared to the other scenarios, reaching only around 400–450 TWh by 2060. This reduced growth is closely linked to the limited deployment of electrolysis, which diminishes the need for large-scale electricity expansion. As a result, the overall electricity demand is also comparatively lower, particularly in relation to hydrogen production. While renewable energy sources still contribute to the generation mix, their expansion is less pronounced, and the system retains a more diversified structure with continued contributions from gas and other conventional sources. The reduced role of electrification in end-use sectors, combined with a stronger reliance on alternative energy carriers such as imported hydrogen and synthetic fuels (as observed in the hydrogen figure), explains the comparatively moderate growth of the electricity system in this scenario.

Overall, the figure highlights two contrasting pathways for Türkiye’s electricity sector: The GoRES, NECP Essentials, and REPowerEU++ scenarios reflect a highly electrified, renewable-intensive transition, where electricity becomes the central energy carrier supporting both direct consumption and hydrogen production. These pathways are consistent with deep decarbonisation strategies and imply significant investments in renewable capacity, grid infrastructure, and system flexibility. In contrast, the Trinity scenario represents a less electricity-centric transition, where the role of the power sector is comparatively limited due to the reliance on external hydrogen supply and alternative conversion pathways. This divergence has important implications for infrastructure planning, investment strategies, and Türkiye’s integration into the broader European energy system, particularly in terms of electricity market coupling, renewable deployment, and cross-sectoral energy integration.

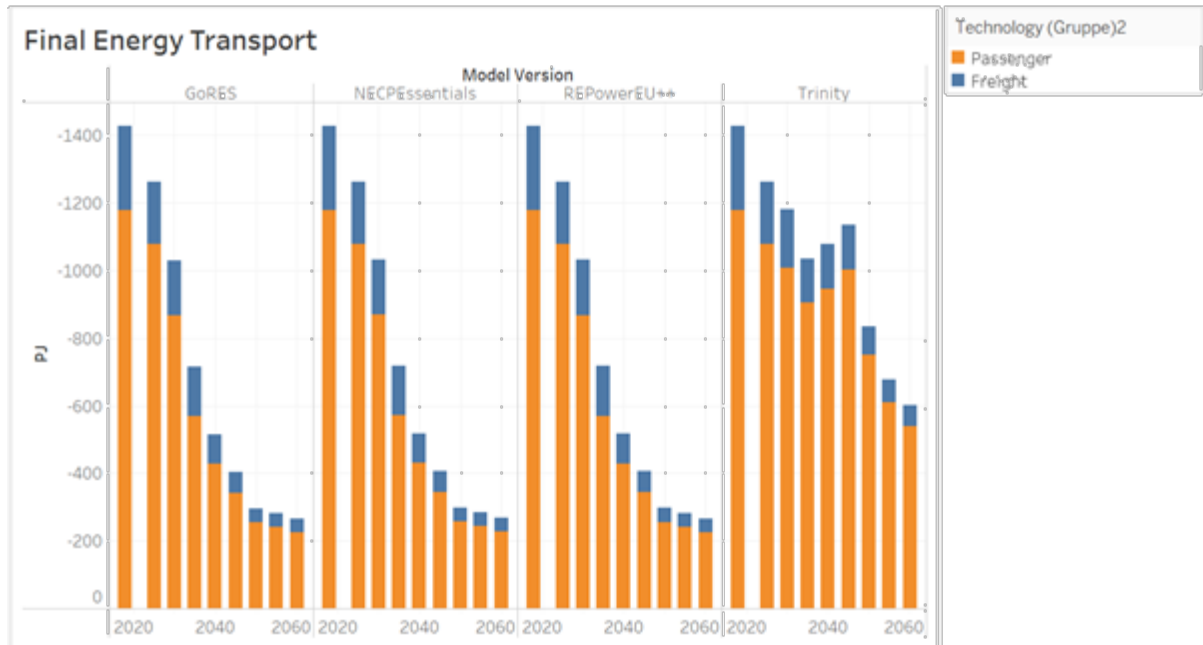


Figure 6.3. Final Energy Consumption in Transport - Hydrogen (PJ).

Figure 6.3 illustrates the evolution of final energy consumption in the transport sector in Türkiye from 2020 to 2060 across four scenarios—GoRES, NECPEssentials, REPowerEU++, and Trinity—measured in petajoules (PJ) and disaggregated into passenger and freight transport. The negative values represent energy demand, with the magnitude indicating the total consumption level. Across the GoRES, NECPEssentials, and REPowerEU++ scenarios, a pronounced and consistent decline in total transport energy demand is observed over time. Starting from approximately 1400–1450 PJ in 2020, total demand decreases sharply to around 250–300 PJ by 2060, representing a reduction of nearly 75–80%. This substantial decrease reflects strong improvements in energy efficiency, large-scale electrification of transport, and a structural shift toward less energy-intensive mobility systems. Passenger transport accounts for the majority of energy consumption throughout the period, although both passenger and freight segments exhibit similar downward trends, indicating system-wide transformation rather than sector-specific changes.

The reduction in energy demand is particularly steep between 2030 and 2050, suggesting an accelerated transition phase during which conventional internal combustion engine vehicles are progressively replaced by more efficient electric alternatives. The relatively low levels of energy demand observed after 2050 imply a mature, highly optimised transport system dominated by electrification and possibly supported by alternative fuels such as hydrogen in specific applications. The similarity in trends across the GoRES, NECPEssentials, and REPowerEU++ scenarios indicates a strong consensus in modelling assumptions regarding transport decarbonisation, with only minor variations in the rate of decline.

In contrast, the Trinity scenario presents a markedly different trajectory. While transport energy demand also decreases over time, the reduction is significantly more gradual, declining from around 1400 PJ in 2020 to approximately 600 PJ by 2060. This corresponds to a reduction of roughly 55–60%, which is considerably less pronounced than in the other scenarios. The higher residual energy demand suggests a slower pace of electrification and efficiency improvements, as well as a continued reliance on energy carriers that are less efficient than direct electricity use, such as synthetic fuels or imported hydrogen-derived products. Both passenger and freight transport maintain relatively higher

consumption levels throughout the period, indicating that the transition toward low-energy mobility systems is less advanced in this pathway.

Similar to previous figures, this figure also highlights two distinct transition patterns in Türkiye's transport sector. The GoRES, NECPEssentials, and REPowerEU++ scenarios reflect a rapid and deep decarbonisation pathway characterised by strong electrification, efficiency gains, and significant reductions in final energy demand. In contrast, the Trinity scenario represents a more moderate transition, where alternative fuels and lower electrification rates result in higher long-term energy consumption. These differences have important implications for infrastructure development, energy system planning, and emissions reduction strategies, particularly in terms of electricity demand growth, fuel supply chains, and alignment with broader European decarbonisation objectives.

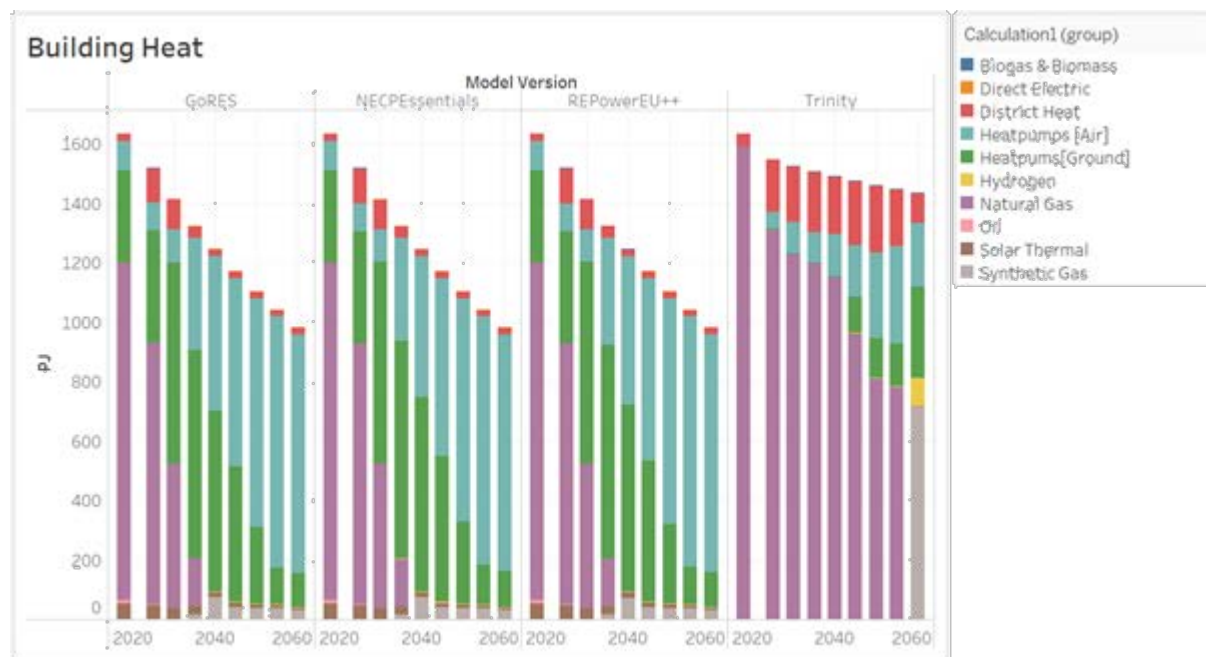


Figure 6.4. Heat Supply in Buildings Sector (PJ).

Figure 6.4 illustrates the evolution of building heat supply in Türkiye from 2020 to 2060 across four modelled scenarios, expressed in PJ and disaggregated by heating technology. A clear downward trend in total heat demand is observed in the GoRES, NECPEssentials, and REPowerEU++ scenarios, where demand declines from approximately 1600 PJ in 2020 to around 1000 PJ by 2060. This consistent reduction reflects the impact of strong energy efficiency improvements in the building sector, likely driven by enhanced insulation standards, retrofitting measures, and policy interventions aimed at reducing overall energy consumption. In contrast, the Trinity scenario maintains a comparatively high level of heat demand throughout the period, remaining above 1400 PJ even by 2060, which suggests a slower uptake of efficiency measures or a more conservative assumption regarding demand reduction.

A significant structural shift in the heating mix is evident in the policy-driven scenarios, characterised by the rapid phase-out of fossil fuels, particularly natural gas. In 2020, natural gas dominates the heating mix, contributing the largest share of total demand across all scenarios. However, in GoRES, NECPEssentials, and REPowerEU++, its contribution declines sharply over time and is nearly eliminated by 2060. Oil, which already represents a minor share in 2020, is fully phased out early in the transition across all scenarios. This indicates a strong alignment with decarbonisation objectives and a clear move away from carbon-intensive energy sources. In contrast, the Trinity scenario exhibits a different



trajectory, with natural gas remaining a dominant energy carrier even in 2060, accounting for a substantial portion of the heating demand. This persistence implies a delayed or less ambitious decarbonisation pathway, potentially due to technological, economic, or policy constraints.

The reduction in fossil fuel use is accompanied by a pronounced increase in electrification, primarily through the deployment of heat pumps. Air-source heat pumps emerge as the dominant technology in the transition, expanding rapidly from a negligible share in 2020 to becoming the primary source of heating by 2040 and maintaining this dominance through 2060 in the GoRES, NECPEssentials, and REPowerEU++ scenarios. Their contribution reaches close to 900–1000 PJ, effectively replacing natural gas as the backbone of the heating system. Ground-source heat pumps also exhibit growth, though at a more moderate scale, providing a stable supplementary contribution throughout the transition period. This pattern highlights the central role of electrification in achieving deep decarbonisation in the building sector and reflects strong policy support for heat pump technologies in line with broader European energy transition strategies.

District heating maintains a moderate and relatively stable presence across the scenarios, with its contribution increasing slightly during the mid-transition period, particularly around 2030 to 2040, before stabilising or gradually declining. This suggests that while district heating plays an important role, particularly in urban areas, its expansion may be constrained by infrastructure requirements and investment limitations, preventing it from becoming the dominant solution. Similarly, other low-carbon technologies such as biogas, biomass, and solar thermal contribute only marginally to the overall heating mix. Their relatively stable but limited shares indicate that they serve as complementary solutions rather than primary drivers of the transition.

The role of emerging energy carriers such as hydrogen and synthetic gas remains minimal across most scenarios, with only slight contributions appearing toward the later years, particularly around 2050 and beyond. This limited uptake suggests that these technologies are not considered cost-effective or scalable for widespread deployment in the building heating sector within the modelled timeframe and are likely reserved for niche applications or hard-to-electrify segments. Notably, the Trinity scenario shows some introduction of synthetic gas in the later years, which, combined with the continued reliance on natural gas, indicates a preference for maintaining existing gas-based infrastructure rather than transitioning fully to electrified solutions.

Overall, the figure demonstrates that under ambitious policy scenarios, Türkiye's building heating sector undergoes a substantial transformation characterised by reduced energy demand, near complete decarbonisation, and a strong shift toward electrification through heat pumps. In contrast, the Trinity scenario represents a less aggressive transition pathway, with higher energy demand and continued dependence on fossil fuels. These contrasting outcomes underscore the critical importance of policy ambition and technological adoption in shaping the future trajectory of the building sector and achieving long-term climate targets.

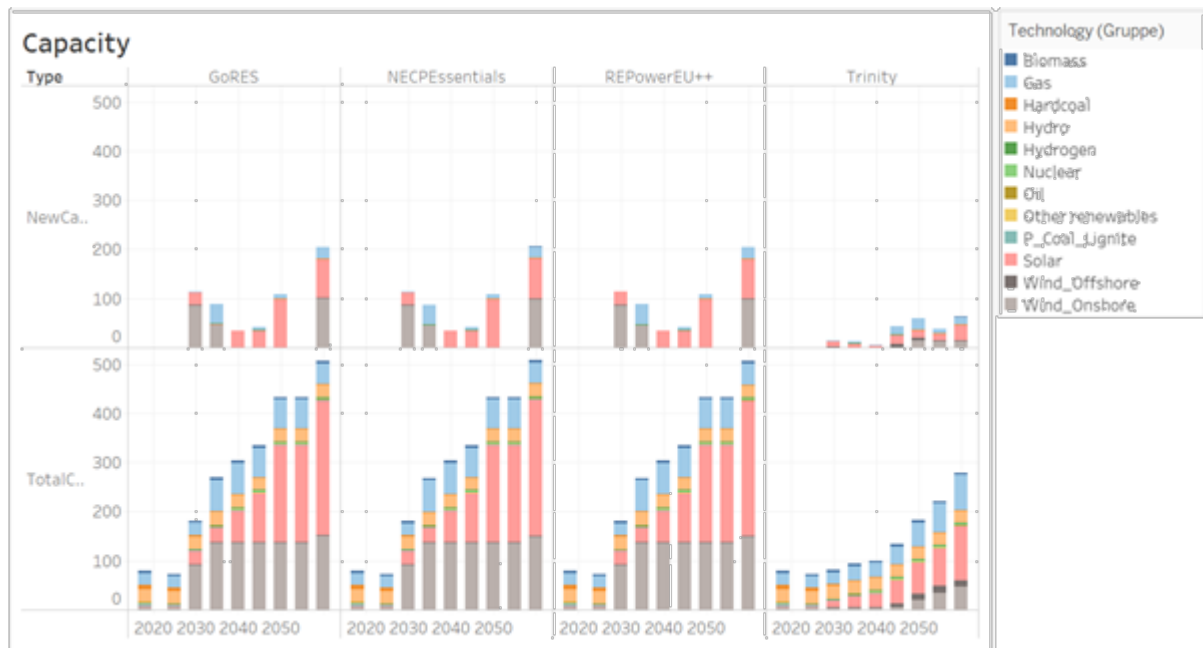


Figure 6.5. Evolution of Power Sector Capacity (GW) across scenarios.

Figure 6.5 presents the evolution of electricity generation capacity in Türkiye across four scenarios, distinguishing between newly installed capacity and total cumulative capacity by technology over the period from 2020 to 2050. A consistent pattern emerges across the three policy-driven scenarios (GoRES, NECPEssentials, and REPowerEU++), where total installed capacity increases substantially over time, reflecting both rising electricity demand and a strong shift toward low-carbon energy systems. In these scenarios, total capacity grows from below 100 GW in 2020 to approximately 500 GW by 2050, indicating a large-scale expansion of the power system. This growth is primarily driven by renewable energy technologies, with solar and wind power constituting the largest shares of capacity additions. Solar energy exhibits the most significant expansion among all technologies. In all three ambitious scenarios, solar capacity increases rapidly after 2030 and becomes the dominant contributor to total capacity by 2050. The steep growth trajectory of solar reflects its declining costs, scalability, and alignment with decarbonisation targets. Wind energy, particularly onshore wind, also shows strong and steady growth throughout the period, contributing substantially to the overall capacity mix. Offshore wind appears to play a more limited but still notable role, particularly in later years, suggesting gradual diversification of wind resources. Hydropower remains relatively stable across all scenarios, indicating that most economically viable hydro resources are already exploited, leaving limited room for further expansion.

Fossil fuel-based capacity, particularly coal (including lignite) and natural gas, shows a clear declining trend in relative importance within the total capacity mix. While some gas capacity persists, likely to provide system flexibility and backup for variable renewables, its share does not grow proportionally with total capacity. Coal capacity remains largely stagnant or declines slightly, reflecting a gradual phase-out in line with climate policies. Oil-based generation is negligible throughout the period, indicating its marginal role in Türkiye's power system. Nuclear energy appears as a modest but stable contributor in later years, suggesting limited deployment as part of the diversification strategy.

The pattern of new capacity additions further reinforces these trends. Annual or periodic additions are dominated by solar and wind technologies, particularly after 2030, highlighting the acceleration of renewable deployment. Early investments include a mix of wind, solar, and some gas capacity, but over time, the focus shifts almost entirely toward renewables. This indicates a transition from a



diversified expansion phase to a more targeted renewable-driven growth strategy. The relatively small contributions from hydrogen and other emerging technologies suggest that they are not yet significant in terms of installed capacity, although they may play a role in other parts of the energy system not captured directly in generation capacity.

In contrast, the Trinity scenario presents a different trajectory. Both new and total capacity levels are significantly lower compared to the other scenarios, with total capacity reaching only around 250–300 GW by 2050. This indicates a more conservative expansion of the power system, potentially reflecting lower demand growth or reduced policy ambition. The technology mix in Trinity is also less dominated by renewables, with a more gradual increase in solar and wind capacity and a continued presence of fossil fuel-based generation. Gas capacity, in particular, remains more prominent, suggesting ongoing reliance on conventional generation technologies. The slower pace of renewable deployment and lower overall capacity expansion imply a delayed energy transition relative to the other scenarios.

Overall, the figure highlights a clear divergence between ambitious, policy-driven pathways and a more conservative scenario. In GoRES, NECP Essentials, and REPowerEU++, Türkiye's power system undergoes rapid expansion and deep decarbonisation, driven mainly by large-scale deployment of solar and wind energy, supported by stable contributions from hydro and limited use of gas for flexibility. In contrast, the Trinity scenario reflects a slower transition with lower capacity growth and continued reliance on fossil fuels. These results underscore the critical role of policy ambition, investment in renewable technologies, and system planning in shaping the future electricity mix and achieving long-term climate objectives.



Figure 6.6. Integrated Energy System Balance (PJ).

Figure 6.6 illustrates the evolution of electricity production in Türkiye from 2020 to 2050 across four scenarios—GoRES, NECP Essentials, REPowerEU++, and Trinity—showing both generation (positive values) and demand or consumption-related components (negative values) across a wide range of technologies. A clear upward trend in total electricity generation is observed in all scenarios, reflecting increasing electrification across sectors such as heating, transport, and industry. Total generation rises from approximately 5,000–6,000 units in 2020 to higher levels by 2050, with the most pronounced



growth occurring in the policy-driven scenarios of GoRES, NECPEssentials, and REPowerEU++, where electrification strategies are more aggressive.

Across these ambitious scenarios, renewable energy sources—particularly solar and wind—emerge as the dominant contributors to electricity generation. Solar photovoltaic technologies, including both utility-scale and rooftop installations, show a rapid and sustained increase over time, becoming one of the largest components of the generation mix by 2040 and 2050. Wind generation, especially onshore wind, also expands significantly, contributing a stable and substantial share throughout the period. This strong growth in variable renewable energy reflects both cost competitiveness and alignment with decarbonisation targets. Hydropower maintains a relatively constant contribution across all scenarios, indicating limited expansion potential but continued importance as a stable and dispatchable renewable resource.

Conventional thermal generation technologies, including coal (both hard coal and lignite) and natural gas-based combined cycle plants, show a gradual decline in their relative contribution to total generation in the ambitious scenarios. While these technologies still play a role, particularly in the earlier years and for system balancing, their share diminishes over time as renewable penetration increases. Gas-fired generation remains present, likely due to its flexibility and role in ensuring system reliability under high shares of intermittent renewables. Biomass-based CHP plants contribute modestly and remain relatively stable, indicating their niche role in the system.

An important feature of the figure is the representation of demand and storage-related components as negative values. Electricity demand increases steadily over time, becoming more pronounced in later years, particularly in GoRES, NECPEssentials, and REPowerEU++. This reflects the electrification of end-use sectors, including the uptake of electric vehicles, heat pumps, and electrified industrial processes. The presence of storage technologies, such as batteries (Li-ion and redox), pumped hydro storage (PHS), and compressed air energy storage (CAES), is also evident. These technologies exhibit increasing activity over time, with both charging (negative values) and discharging (positive values) contributions, highlighting their growing role in balancing supply and demand in a renewable-dominated system.

Hydrogen-related technologies also begin to appear more prominently in the later years, particularly in the more ambitious scenarios. These include hydrogen production (electrolysis) and hydrogen-based storage or conversion technologies, which contribute to both electricity consumption and generation depending on their operational mode. Their increasing presence suggests a growing role for sector coupling and energy storage solutions in managing variability and ensuring system flexibility.

In contrast, the Trinity scenario exhibits a more moderate transition. While renewable generation still increases, the overall growth in electricity production is less pronounced compared to the other scenarios. Conventional generation, particularly gas-based technologies, retains a more significant role throughout the period, indicating a slower shift away from fossil fuels. Electricity demand also increases but at a comparatively lower rate, suggesting less extensive electrification of end-use sectors. The deployment of storage and hydrogen technologies is also more limited, reflecting a less advanced integration of flexibility solutions.

Overall, the figure highlights the transformation of Türkiye's power system under different policy pathways. In the ambitious scenarios, the system evolves toward a highly electrified and renewable-based structure, supported by significant investments in storage and emerging technologies to ensure flexibility and reliability. In contrast, the Trinity scenario reflects a more gradual transition with continued reliance on conventional generation and lower levels of electrification. These differences



underscore the importance of policy ambition and technological deployment in shaping the future electricity production landscape and achieving long-term decarbonisation goals.

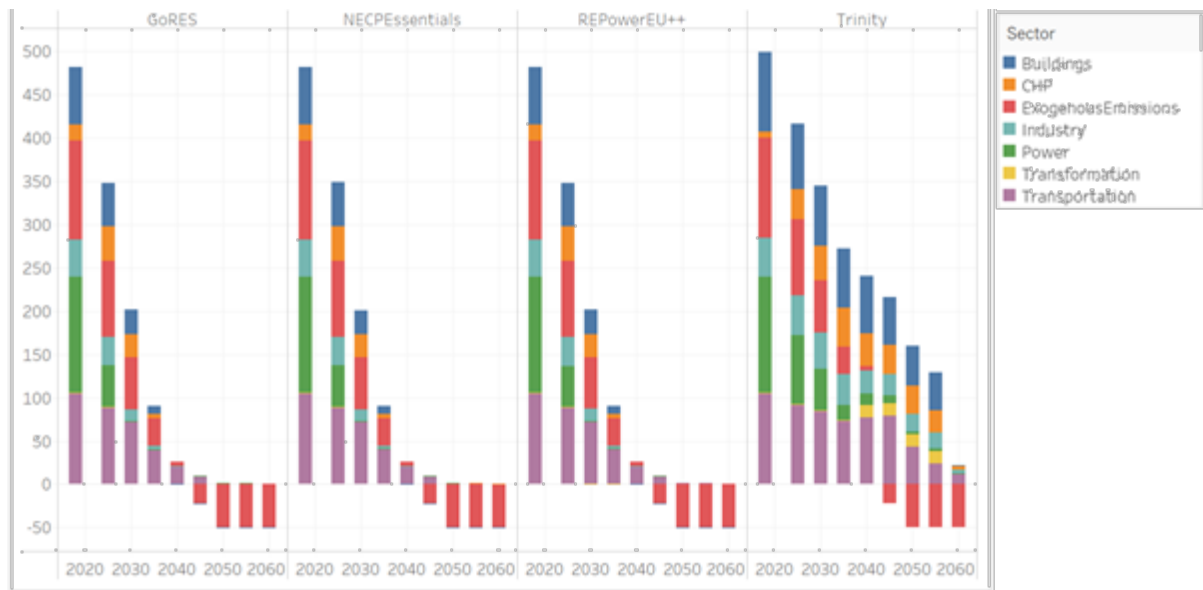


Figure 6.7. Comparative sectoral emissions in Türkiye across different scenarios (in Mt CO₂-eq).

Figure 6.7 presents a comparative assessment of emissions across four scenarios—GoRES, NECP Essentials, REPowerEU++, and Trinity—disaggregated by sector over the period 2020–2060. The initial emissions levels in 2020 are broadly comparable across all scenarios, reflecting a consistent baseline assumption, although minor variations in sectoral contributions are evident. At the starting point, the transportation sector constitutes the largest share of emissions, followed by the power and industry sectors, indicating the significant role of mobility demand alongside energy production and industrial activity in Türkiye’s emissions profile. Contributions from buildings and CHP remain moderate, while transformation-related emissions are comparatively limited.

Over time, all scenarios exhibit a declining trend in total emissions, particularly from 2030 onwards, although the pace of reduction differs. The GoRES and NECP Essentials scenarios reflect gradual decarbonisation pathways, with steady but moderate declines. The REPowerEU++ scenario demonstrates a comparatively faster reduction trajectory, suggesting stronger policy ambition and more rapid deployment of low-carbon technologies. The Trinity scenario, while characterised by relatively higher emissions in earlier years, also follows a consistent downward trend, converging toward lower emission levels in the long term rather than representing a distinctly slower decarbonisation pathway.

Sectoral analysis indicates that emissions reductions are distributed across multiple sectors, notably power, transportation, and industry, all contributing significantly to the overall decline. The power sector shows substantial reductions over time, consistent with increasing penetration of renewable energy sources. Similarly, transportation emissions decrease progressively, reflecting potential electrification and efficiency improvements, although they remain a notable contributor throughout the horizon. Industrial emissions also decline but persist as a residual source, highlighting the challenges associated with decarbonising hard-to-abate sectors.

A notable feature across most scenarios is the emergence of negative exogenous emissions after approximately 2040, which contributes to further reductions in net emissions toward 2050 and beyond. This trend indicates the inclusion of modelled negative emission mechanisms or offsets within the system boundaries, rather than being attributable to a single sectoral transition.



Overall, the figure highlights that while all scenarios achieve significant emissions reductions over time, the extent and pace of decarbonisation vary, with more ambitious pathways demonstrating earlier and deeper reductions. The results underline the importance of coordinated multi-sectoral transitions, including power system decarbonisation, transport electrification, and industrial transformation, to achieve long-term emission reduction objectives.

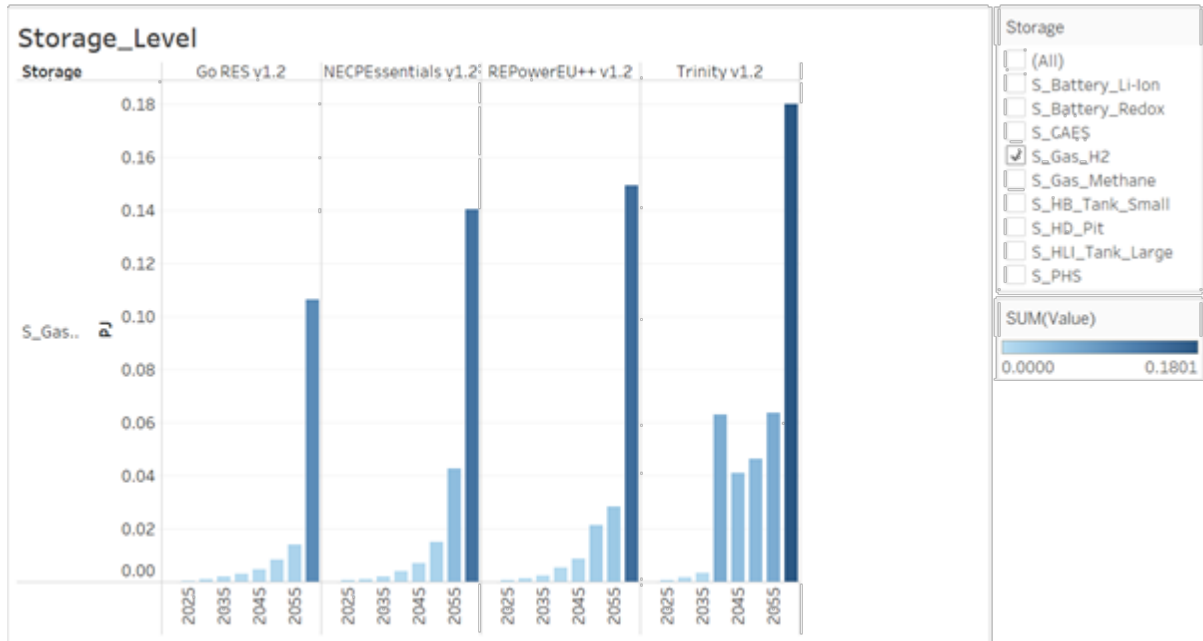


Figure 6.8. Hydrogen Storage Level (PJ)

Figure 6.8 presents the evolution of hydrogen-based storage ($S_{\text{Gas_H2}}$) across multiple energy system models—Go RES v1.2, NECP Essentials v1.2, REPowerEU++ v1.2, and Trinity v1.2—over the period from 2025 to 2055. The y-axis represents storage levels (in PJ), while the x-axis captures time progression in five-year increments. Across all scenarios, hydrogen storage deployment in Turkey starts from negligible levels in 2025, indicating that hydrogen infrastructure is either not yet developed or plays a minimal role in the early system configuration. However, a clear upward trend emerges toward 2050 and especially 2055, reflecting a gradual but decisive integration of hydrogen as a long-term energy storage solution.

The most pronounced growth is observed in the Trinity (v1.2) scenario, where hydrogen storage reaches approximately 0.18 PJ by 2055. This suggests a strong reliance on hydrogen technologies in this pathway, likely driven by deeper decarbonisation targets or higher penetration of variable renewable energy sources such as wind and solar. The steep increase between 2045 and 2055 indicates a late but rapid scale-up phase, possibly due to technological maturity, cost reductions, or supportive policy frameworks. Similarly, the REPowerEU++ v1.2 scenario shows substantial growth, reaching around 0.15 PJ by 2055. This reflects alignment with ambitious European decarbonisation strategies, where hydrogen plays a critical role in balancing the system and enabling sector coupling. The trajectory here is smoother than Trinity but still demonstrates a significant acceleration post-2040. The NECP Essentials v1.2 scenario exhibits moderate growth, achieving approximately 0.14 PJ by 2055. While still significant, the slightly lower level compared to REPowerEU++ and Trinity suggests a more conservative or incremental approach to hydrogen deployment, possibly constrained by investment, infrastructure, or policy ambition. In contrast, the Go RES v1.2 scenario shows the lowest uptake among the four, with hydrogen storage reaching just above 0.10 PJ by 2055. Although growth



is still evident, the comparatively lower values indicate that this pathway may prioritise other flexibility options or assumes slower hydrogen market development.

Overall, the comparison across scenarios highlights that hydrogen storage becomes increasingly important in Turkey's energy system toward mid-century, but the extent of its deployment is highly scenario dependent. More ambitious decarbonisation pathways consistently drive higher hydrogen storage capacities, underlining its role as a strategic flexibility option for integrating high shares of renewables and ensuring system reliability.

6.4.2. NECPs

The findings and assumptions of this case study are closely aligned with Turkey's climate and energy plans and related strategic documents, ensuring that the modelled pathway supports national priorities. Firstly, the net-zero 2053 target is explicitly built into the scenario – the model meets an emissions trajectory that reaches carbon neutrality by 2053, echoing Turkey's official commitment. This means all sectors contribute to deep decarbonisation, with hydrogen playing the role outlined by national strategy (replacing fossil fuels where electrification is difficult). The scenario's hydrogen development is also consistent with the **Turkey Hydrogen Strategy and Roadmap**: the model results achieve approximately 5 GW of electrolyser capacity by 2035, matching the NEP's interim target and then scale up hydrogen production further to approach the **70 GW by 2053 vision**. In doing so, the scenario supports Turkey's goal of becoming a regional hydrogen exporter and technology leader.

Additionally, the integrated model assumes ambitious improvements in energy efficiency and electrification in line with Turkey's NECP expectations. By 2035, primary energy intensity improves by around 35%, which mirrors the NEP's target of a 35.3% reduction in energy intensity (versus 2020) through efficiency measures across all sectors. This reduction is achieved in the model via measures like industrial process optimisation, building insulation, and efficient appliances – all exogenous inputs consistent with Turkey's Climate Change Mitigation Action Plan.

Electrification of demand is another pillar: the scenario reflects the NEP projection that the share of electricity in final energy consumption rises from about 22% in 2020 to ~25% by 2035 and continues further to exceed 50% by 2053 as Turkey's energy system transforms. Such high electrification (over half of final energy by mid-century) aligns with both the NECP and the EU's broader decarbonisation scenarios, indicating consistency between national efforts and European trends. The electrification is driven by the uptake of electric vehicles, heat pumps, and electric industrial processes in our model – all assumptions cross-checked with Turkey's national plans (e.g. EV deployment targets and industrial electrification goals in the 2024–2030 Climate Action Plan). Meanwhile, hydrogen serves to decarbonise the remaining energy uses that are not easily electrified, alleviating also the transmission lines' congestion, which is exactly the role envisaged in Turkey's climate strategy (e.g. using hydrogen for heavy industry and blending into gas networks by 2053). Lastly, the scenario's renewable energy expansion is aligned with NECP targets, such as reaching ~65% renewable share in power generation by 2035 and beyond, ensuring our model does not wildly exceed or undershoot official expectations.

In conclusion, the case study's modelling outcomes are not only technically and economically optimised but also **policy-coherent** – they support Turkey's NECP objectives of net-zero emissions, enhanced efficiency, large-scale electrification, and strategic hydrogen development, thereby providing a plausible pathway for real-world policy implementation.



6.4.3. Supplementary Data

To support transparency and allow replication, a comprehensive set of supplementary data and scenario details will be provided in the appendices. This will include **scenario parameters** (all key inputs and assumptions used in the model runs), such as technology cost trajectories, fuel price projections, demand growth rates, and policy targets for each scenario variant. We will also supply the specific **hydrogen-related assumptions** – for example, electrolyser capital costs, efficiency and lifetime assumptions, hydrogen storage costs and capacities, and fuel cell performance characteristics – that underpin the hydrogen integration analysis. These assumptions are drawn from open sources and aligned with both EU and Turkish references. Furthermore, in the Zenodo link, details on the **spatial and temporal resolution** of the model are provided: how Turkey is regionally represented in GENeSYS-MOD (if applicable) and the time-slice structure used to capture daily/seasonal variations for renewables and hydrogen operations. Finally, we include an overview of the **scenario definitions** (storylines) analysed in this case study (e.g. baseline vs. hydrogen-boost scenario), and any deviations from default GENeSYS-MOD configurations. All supplementary information follows the project’s open-data ethos, enabling interested stakeholders to review the assumptions and even run the model themselves.

This additional data is intended to provide full context for the results, ensure reproducibility of the findings, and offer granular insights that could not be exhaustively covered in the main report.

Gokhan, K. (2026). ManOEUVre Case Study 6 data files [Data set]. Zenodo.

Case study 7: Greece as a renewable energy hub

The purpose of the seventh case study is the examination of Greece’s potential to become a medium- and longer-term renewable energy hub within the European-MENA region. In this study, we examined and compared Greece’s potential for domestic production, transportation, and re-export of various energy carriers, including renewable electricity, green hydrogen, synthetic fuels, and green ammonia. The aim was to identify the interrelationships among these carriers and determine the optimal combination of resources, infrastructure, and technical and economic conditions required to make this potential a reality. To this end, we performed simulation analyses of the Greek energy market and its interconnections with neighbouring countries using the *PRIMES* energy system model. An energy system analysis was then conducted to evaluate emissions, costs, and investments in line with the targets of the net-zero greenhouse gas strategy, which also assessed the impact of available infrastructure (e.g. new electrical interconnections with Egypt, which could enable further exports to Italy and Germany or to the South-East European market).

7.1. Accomplished Tasks

Task 7.1 – Model enhancement & calibration: In this task, the Electricity, Heat/Steam, and Clean Fuels modules of PRIMES were expanded to better align with the targets of this case study. Following a significant update to the technoeconomic data used, the PRIMES hydrogen and synthetic fuels module was further enhanced, including the addition of production technologies, transportation options, and interlinkages with other modules. Further improvements to the power and heat supply modules were made in conjunction with an update to the input calibration databases, including existing power plant capacities. Following the completion of these enhancements, some initial simulations based on existing PRIMES scenarios were run for testing purposes, including assumptions on future interconnection infrastructure of electricity and hydrogen.



Task 7.2 – Data updates to include the latest information and data from final NECPs 2024: This task focused on gathering and implementing NECP data related to the targets and policies submitted by the member states of the EU and the rest of the countries that may impact this case study's results (e.g. non-EU Balkan states). This task was delayed in its conclusion, mainly because not all NECPs were submitted on time.

Task 7.3 – Model simulations: Following the implementation of the targets of the final Greek NECP, and in conjunction with the model testing started in Task 7.1, the scenario designing and simulation phase was initiated. As a first step, a detailed evaluation of Greece's sectoral demand for electricity, hydrogen and synthetic fuels, focusing on the latter, which is an ongoing research topic with little to no actual data to calibrate on, was conducted. A reference scenario, not based on the EU-EnVis data, was created. Subsequent scenarios based on the GoRES EnVis scenario and Greece's NECP have been developed to assess the impact of several factors, the most important of which is expected to be variations in export demand, since the aforementioned analysis indicated that domestic demand is not likely to vary significantly.

Task 7.4 – Results analysis and impact assessment: In this final task, the evaluation of the simulation process's outputs per scenario and a comparison between them on fuel consumption, power generation by plant type, emissions, fuel prices, imports/exports, etc., are conducted.

7.2. Planned impact

The results of the case study provide policymakers, investors, and infrastructure authorities with a deeper understanding of how Greece's energy system could evolve under different electricity, hydrogen and synthetic fuel deployment pathways. By comparing scenarios that examine delayed hydrogen infrastructure, export-oriented synthetic fuel production and domestic self-reliance, the analysis offers complementary insights to those in the Greek NECP. It highlights how Greece's substantial renewable resources could support a future role as an electricity and/or hydrogen and synthetic fuels hub in the European – MENA region.

The scenario outcomes, covering the evolution of the electricity mix, the scale of renewable deployment, the role of hydrogen and e-fuels, and the resulting import - export configurations, can support strategic decision making for long-term energy planning, infrastructure prioritisation and regional cooperation. They also highlight the system implications of different strategic orientations, including the renewable capacity, storage needs and hydrogen infrastructure required to enable domestic decarbonisation and, where relevant, potential export activity.

In doing so, the case study does not seek to replace or critique the roadmap set out in the NECP, but rather to enrich it by illustrating the broader set of possibilities that could arise as hydrogen and synthetic fuel markets develop across Europe and neighbouring regions.

7.3. Implementation

Following the finalisation of PRIMES' modelling enhancements, calibration, and testing, a routine for data import from the IAMC format used in the EU EnVis scenarios, with appropriate implementation and mapping to the PRIMES model, was designed. To guide the determination of crucial parameters (such as demand and costs), a more detailed elaboration was employed to represent better the specific case study in the final scenario design. The PRIMES model was used for each case, and a total energy system analysis, comparison, and impact assessment have been conducted for all of them.



7.3.1. Challenges

The primary challenge in Case Study 7 was aligning the GENeSYS-MOD data outputs with those of the PRIMES model. There are possible discrepancies in assumptions about efficiencies and capacities, as well as variations in the availability of necessary parameters in the GENeSYS-MOD outputs. Additionally, differences in the structural modelling approaches, such as how sectoral demand is modelled, make achieving full compatibility quite complex.

7.3.2. Mitigation Measures

To effectively navigate the challenges in Section 7.3.1, we have chosen to focus on specific outputs, particularly electricity demand, capacity levels, and pricing. This strategy facilitates the implementation of distinct storylines for each EU-EnVis scenario while incorporating the necessary assumptions about missing data already established in the PRIMES model. EnVis scenarios version 1.2 was used in all simulations.

A baseline scenario, based on the EU member states' NECPs and assumed to achieve the targets set at the European level, mainly, was designed to address data and assumption gaps related to the structural differences between GENeSYS-MOD and PRIMES. The scenario was extensively tested and serves as the underlying assumption whenever discrepancies arise between the two models.

The total final energy demand and power plant cost data of GENeSYS-MOD was used across all countries represented, while for the rest, the PRIMES baseline scenario values were used. Due to PRIMES having a much more disaggregated sectoral allocation, and achieving targets is closely associated with sectoral behaviour, the demand sectoral allocation of the baseline scenario was applied to the total final energy demand of the EnVis scenarios, instead of a mapping between the models. Hydrogen and synthetic fuel demand are either too low or non-existent in the EnVis scenarios. This was incompatible with the case study's target of evaluating the effects of different energy carriers on Greece's potential as an energy hub, as well as with Greece's NECP, which explicitly includes projections of synthetic fuels demand. As such, the baseline scenario projections were used as the associated demand for each scenario in the four final simulations. In these projections, Greece's final energy consumption and production of Renewable Fuels of Non-Biological Origin (RFNBOs) follows its NECP, while endogenously calculated, export-oriented expansion upon that base capacity is allowed depending on the scenario. The underlying assumption is that Greece's hydrogen production benefits from a strong RES potential and, as such, lower prices and demand from central Europe are the main drivers for exports, given either local interconnections with South-Eastern Europe countries such as Bulgaria and Romania or a fully interconnected pipeline network as predicted by the European Hydrogen Backbone. Synthetic fuel production is assumed to be consistent with refinery activity at the European level; this reflects an assumed business shift of refinery activity from the production of fossil fuels to the production of synthetic fuels, given the accumulated knowledge in fuel production, land and infrastructure availability etc. The cost data assumed for hydrogen and synthetic fuels production do not follow the EnVis scenarios, as a variety of production technologies (PEM, Alkaline, SOEC electrolyzers for hydrogen, Fischer Tropsch, Methanol-to-X for synthetic fuels, etc.) are modelled and the costs are a result of the technology mix, which is a model decision.

A sensitivity analysis was then conducted, using the GoRES scenario as its basis, exploring variants in electricity, hydrogen and synthetic fuel production, trade and infrastructure. GoRES was selected for this purpose as its assumptions of higher social acceptance, technological growth, and favourable geopolitical conditions would make the more sense as the basis for experimentation with new technologies based on conversion of electricity. It would also make more sense to quantify such effects



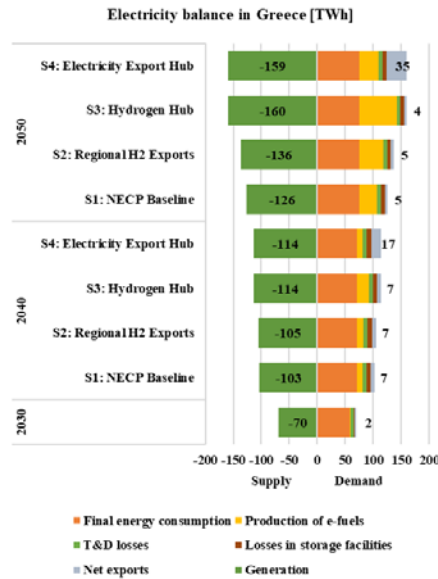
on a scenario where electrification of the energy system is more thorough, to examine its impact on an already high-RES deployment electricity market. The following variants were explored:

- a) A **Baseline** scenario, in which Greece pursues the NECP planning without additional, export-oriented investments. This scenario serves as the basis of evaluating the impact of the other three, export-based scenarios.
- b) A **Regional Hydrogen Exports** scenario, where Greece becomes an exporter of hydrogen to the Southeast European area, which represents a small-scale market with limited volumes of hydrogen demand. This export potential is enabled by the assumed availability of a Greece-Bulgaria pure hydrogen corridor in 2035, with a capacity of 80 GWh/day, co-developed by the Greek and Bulgarian operators.
- c) A **European Hydrogen Hub** scenario, in which a significant uptake of infrastructure development is assumed to support green hydrogen exports to Central Europe and primarily Germany. In this scenario, a South-East hydrogen corridor, interconnected with a pan-European hydrogen network to Austria/Germany etc, in line with the European Hydrogen Backbone, is assumed to have emerged by 2035. A high-voltage DC (HVDC) interconnector between Egypt and Greece is also assumed to be commissioned in 2035, allowing renewable electricity imports coupled with storage to support green hydrogen production if needed.
- d) An **Electricity Export Hub**, which represents the inverse of the hydrogen hub strategy. In this scenario, RES and transmission expansion are driven towards renewable electricity exports towards both South-East and Central Europe, employing HVDC connections of 3 GW with both Egypt and Germany. Hydrogen and e-fuel production follows the NECP and is mainly a means of domestic decarbonisation and balancing, with only minor exports.

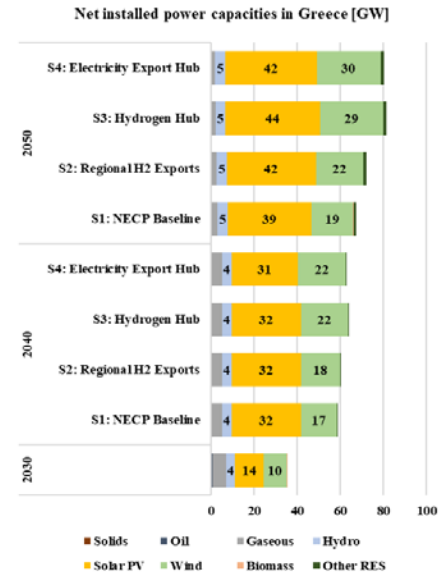
7.4. Results

7.4.1. Outcomes

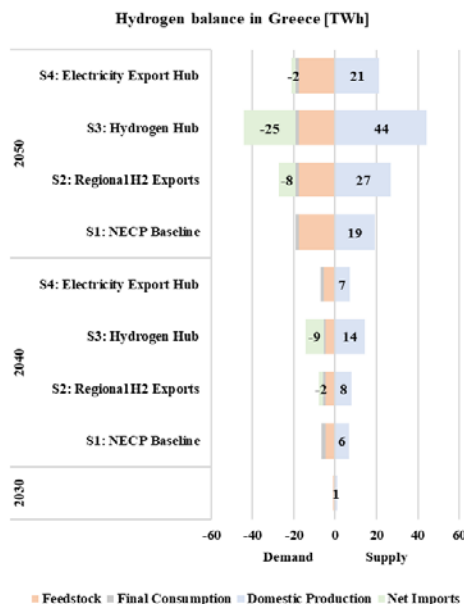
Greece is rapidly transforming its energy system to meet EU climate goals and achieve neutrality by 2050, with the updated NECP targeting over 80% renewable electricity by 2030, supported by grid upgrades, island interconnections, and large-scale storage. Rising electricity demand from electrification, hydrogen, and synthetic fuels will drive further investment. While the NECP focuses on domestic decarbonisation, cross-border projects like HVDC links could position Greece as a regional energy hub, though timelines and market dynamics remain uncertain. This analysis complements the NECP by exploring how such infrastructure could expand Greece's role in regional renewable and fuel exchanges.



(a) Electricity Balance



(b) Net Installed Power Capacities



(c) Hydrogen Balance

Electricity and hydrogen prices (EUR/kWh)		Average electricity price	Hydrogen price
2030	S1: NECP Baseline	142.3	190.7
	S1: NECP Baseline	138.8	117.4
2040	S2: Regional H2 Exports	140.0	121.8
	S3: Hydrogen Hub	142.9	121.5
	S4: Electricity Export Hub	147.2	119.6
	S1: NECP Baseline	130.2	114
2050	S2: Regional H2 Exports	131.6	95.4
	S3: Hydrogen Hub	136.5	99.9
	S4: Electricity Export Hub	157.2	110
	S1: NECP Baseline	142.3	190.7

(d) Electricity and Hydrogen Prices

Figure 7.1. Electricity and hydrogen balances, capacities and prices across scenarios

Figures 7.1 (a) and 7.1 (c) depict the electricity and hydrogen balance for Greece in 2030, 2040 and 2050 for the four alternative scenarios. In 2030, final electricity consumption is 57.6 TWh, closely aligned with the NECP target of 57 TWh, which is mainly the result of decarbonisation efforts in transport and heating. By 2030, lignite use has been phased out and oil-fired capacity decreased significantly due to the advancement of interconnection of non-interconnected islands to the mainland grid. As shown in Figure 7.1 (b), solar PV and wind already dominate the power mix, bringing the energy system close to the target of 81% renewable generation by 2030.

In S1 (NECP Baseline), Greece is still projected to be a net exporter of electricity in the South-East Europe region, exporting 6-8 TWh in the 2040-2050 period, exploiting its renewable energy potential. A substantial increase in electricity demand is also observed during that period, driven both by further decarbonisation efforts and the increase of hydrogen demand, a demand which is mostly driven by

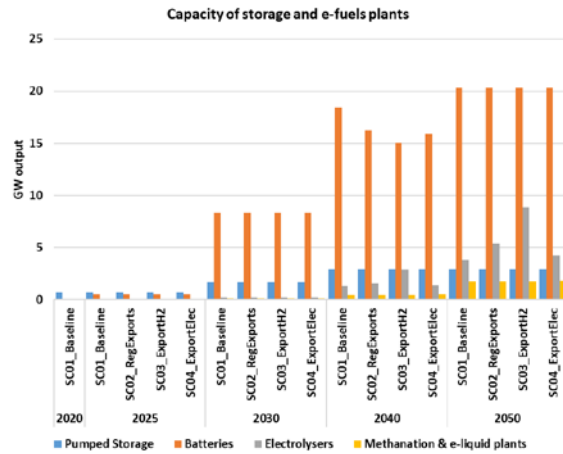


domestic uses in transport and industrial processes and as feedstock for green ammonia and methanol according to its NECP. In this scenario, capacity expansion is mainly driven by domestic electrification and hydrogen needs and proceeds steadily over the future years, with storage growing accordingly to enable higher renewable penetration. As for prices, S1 serves as the reference point, with average electricity prices at about 138.8 €/MWh in 2040 and 130.2 €/MWh in 2050, and hydrogen prices at the range of 118 - 114 €/MWh in 2040 and 2050, benefitting from cheap renewable electricity.

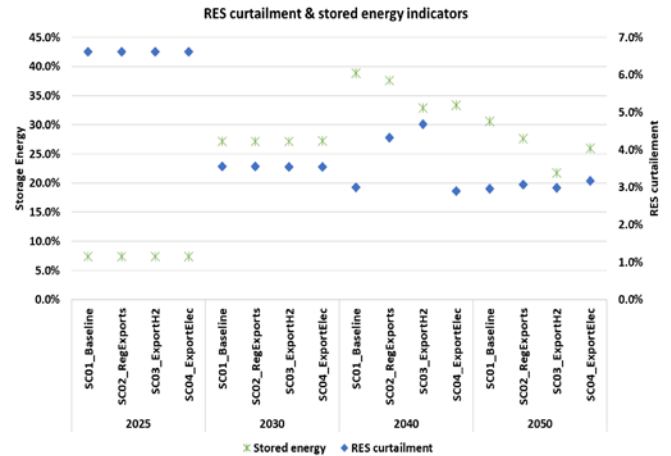
In S2 (Regional Hydrogen Exports), exports of hydrogen begin around 2040 via the Greece-Bulgaria hydrogen pipeline. Hydrogen production is accordingly increasing above S1 levels, at about 2 TWh extra in 2040 and about 8 TWh by 2050. The potential for exports is exploited, but the scale is still at a limited level due to low demand and willingness to pay levels. Capacity development mirrors this modest export role, with about 2 additional GW of solar and wind in 2040 and 6 GW in 2050 compared to S1 supporting these exports. In general, the overall system does not otherwise diverge drastically compared to S1, as the incremental hydrogen output does not fundamentally alter how the power and hydrogen systems interact. Electricity prices are only marginally affected in all years, rising less than 2 €/MWh compared to S1, since most of the additional renewable capacity is used for the production of hydrogen. Hydrogen prices, by contrast, show a more pronounced difference, rising by about 4% in 2040 but falling substantially lower than the baseline, benefitting from electrolyser economies of scale and higher utilisation.

S3 (Hydrogen Hub) sees Greece stepping into a larger exporting role, with hydrogen flows ascending to roughly 9 TWh in 2040 and 25 TWh in 2050, mainly toward Central and Northern Europe through the European Hydrogen Backbone. Additional renewable electricity imported from Egypt supports this hydrogen domestic production increase, while the increased production of hydrogen also reduces energy storage needs. Supporting this shift requires sizeable capacity additions, about 5 GW of additional wind and solar capacities in 2040 and 15 in 2050 compared to the baseline scenario. Electricity prices, while increased, remain at levels relatively close to the baseline scenario (higher by about 4 €/MWh in 2040 and 6 €/MWh in 2050), seeing as the extra RES is largely self-contained within the hydrogen supply chain. Hydrogen prices follow a similar pattern to S2, rising slightly in 2040 compared to the baseline scenario then dropping in 2050, although the significant rise in demand by 2050 and the additional investment needed contributes to the price being slightly higher than S2.

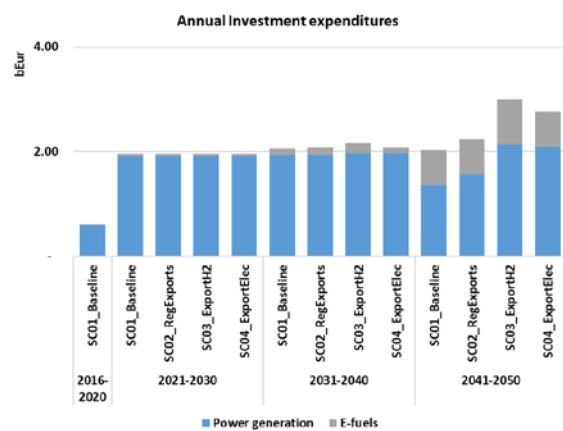
Lastly, in S4 electricity generation is very close to S3, but the system's direction is distinctly different. Greece exports large amounts of electricity to South-East Europe and Central Europe by means of the enhanced HDVC interconnections. Hydrogen production remains comparable to S1, rendering renewable generation for exports as the main stress to the system. Additional RES requirements, which amount to 5 GW in 2040 and 15 GW in 2050 as with the S3 scenario, drive higher storage needs than S3 due to hydrogen's role as an energy carrier in S3 and add additional stress to the grid, which is also reflected in the prices. Average electricity prices climb to almost 10 €/MWh higher than the baseline scenario in 2040 and a whole 27 €/MWh in 2050. By contrast, hydrogen prices fall only modestly (only 2-3% below S1 by 2050), showcasing that electricity export strategies, given that grid RES expansion and renewable imports mostly support exports, have little effect on hydrogen costs.



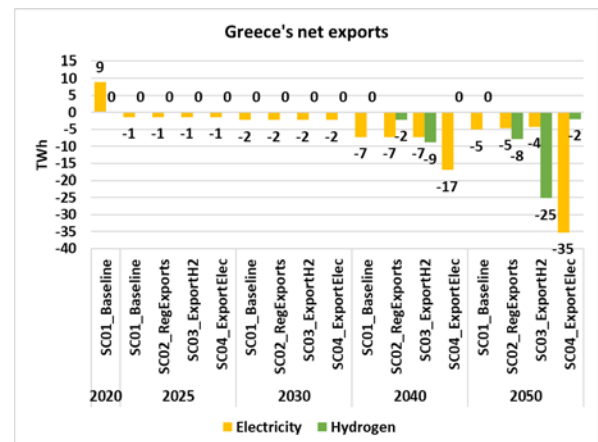
(a) Capacity of energy storage and e-fuel production facilities



(b) RES curtailment and storage energy indicators



(c) Annual investment expenditures



(d) Greece's Net Exports

Figure 7.2. Sensitivity analysis of scenario outcomes

The results exhibit that Greece has, in principle, the potential to support renewable capacity expansion far beyond its domestic consumption, ascending to the level of a regional energy hub. At the same time, grid congestion, storage needs and rising curtailments show that realising such a potential requires significant investment in networks, flexibility and market design. While both the electricity and hydrogen export routes are feasible, the hydrogen-oriented strategy seems to offer more stable long-term revenue prospects and capital recovery on large-scale RES deployment and grid expansion. While electricity exports can still complement Greece's energy strategy as interconnections deepen and integration of regional markets further progresses, Greece's most robust pathway to becoming an energy hubs is likely to lean towards a hydrogen-based export mix, taking advantage of its high RES potential in order to supply green hydrogen to markets with higher willingness to pay, while improving grid flexibility so that electricity exports can also be pursued where operationally feasible and economically advantageous.

7.4.2. NECPs

The revised Greek NECP provides a comprehensive vision for the energy transition up to 2050, focusing on rapid deployment of renewable energy, electrification, grid reinforcement, and the gradual emergence of renewable gases and synthetic fuels. It sets ambitious targets, including 35.5 GW of installed electricity capacity by 2030 and 70.7 GW by 2050; the near-complete phase-out of lignite by 2028, significant expansion of photovoltaic and wind capacity and the development of initial



commercial green-hydrogen production lines, primarily linked to refineries. The NECP also recognises the importance of major interconnections, such as island interconnections and planned grid reinforcements, to support high-RES penetration and system flexibility.

While the NECP's modelling concentrates on domestic decarbonisation and security of supply, it also acknowledges the strategic potential of Greece's geographical position and the transformation of regional gas flows, including the prospect of renewable gases and cross-border exchange evolving in the longer term.

The present study builds on this foundation by exploring how Greece's potential RES capacity expansion, either directed to electricity exports or focused on the emerging hydrogen and synthetic-fuel markets, in combination with future interconnections, could influence Greece's longer-term role in the wider South-East European and Mediterranean energy systems. In doing so, the analysis complements the NECP by shedding additional light on how Greece's strong renewable potential and forthcoming infrastructure projects might support alternative pathways, including scenarios where the country could act as a producer or exporter of electricity or renewable-based energy carriers.

7.4.3. Supplementary Data

The following data from GENESYS-MOD and the EnVis scenarios were used:

- Capital Costs of Power Plants
- Fixed O&M Costs of Power Plants
- Variable Non-Fuel Costs of Power Plants
- Electricity Final Energy (all countries simulated in GENESYS-MOD)

The model's results can be accessed using the following Zenodo DOI: [10.5281/zenodo.19257932](https://doi.org/10.5281/zenodo.19257932)

Case study 8: Green transition in France

The objective of this case study is to analyse the potential for electrification of disaggregated consuming sectors. The study focuses on France but will include simulation of the whole Europe. It investigates the four EnVis-2060 scenarios on selected years, looking at long-term energy policies and realistic development potentials of low-carbon generation and storage, and the massive electrification planned for France. This case study evaluates the potentials for electrification of consuming sectors, renewable electricity generation expansion, reduction of final uses coming from energy efficiency and sobriety, and for other energy vectors such as hydrogen or biofuels, accounting for variable renewable profiles and short-term storage needs.

The French NECP and French strategy regarding the energy system states that achieving carbon neutrality will require **i)** vast electrification of uses, in particular transportation and industry **ii)** reduction of the final energy consumption mainly from energy efficiency (including electrification) and sobriety, and **iii)** significant acceleration in the rate of development of decarbonised electricity generation.

The case study uses the *plan4res* power system model for simulating the power system operation based on the scenarios produced by GENESYS-MOD.



8.1. Accomplished Tasks

Task 8.1 – Adapt the GENeSYS-MOD input data and assumptions for France: The first step was to conduct a comparison of the EnVis-2060 NECP Essentials scenario with the actual NECP for France, with the objective of adapting the inputs of GENeSYS-MOD so that its outputs, regarding the NECP Essentials scenario, are in line with the French NECP. This comparison with version 1.2 of the NECP Essentials scenario allowed to identify the main divergences and to propose measures to mitigate them:

- The sectoral consumption as modelled in GENeSYS-MOD needs to be adapted
- The weight of the different energy vectors needs to be adapted
- The electricity generation mix needs to be adapted
- Electrification of uses is underestimated in all sectors, but particularly in the industry sector, where it is “replaced” by coal and gas

Following this, the version 1.3 of the scenario was created which appeared to be more adapted but with still some divergences:

- The electricity generation mix is reasonably close
- Sectoral consumptions are closer but still present some divergences mainly regarding industry, heating and pure power uses
- The gas share within the total final energy is too high

This comparison allowed to understand the reasons of these discrepancies and the modelling is being adapted.

Task 8.2 – GENeSYS-Mod / plan4res coupling: The objective is to compute “Flexibility need” indicators out of plan4res simulation results. These indicators will be fed back to GENeSYS-MOD in order to help GENeSYS-MOD evaluate the need for flexibility. An analysis of the GENeSYS-MOD algorithm, in particular of the time series reduction methodology has been conducted and a set of indicators, together with the specifications of the way to feed them into GENeSYS-MOD.

Task 8.3 – Scenario analysis and sensitivities run: Plan4res has been linked with the inputs and outputs of GENeSYS-MOD via the IAMC data format and nomenclature, and plan4res simulations have been conducted for the case of the scenario NECP Essentials v1.2 and the year 2030.

8.2. Planned impact

- CS8 includes two main expected results:
 - **Methodological result:** implement a feedback loop for feeding GENeSYS-MOD with information from plan4res simulation. The objective is to provide GENeSYS-MOD feedback about the variability of both power demand and variable power potential generation. The objective is to allow GENeSYS-MOD to produce scenarios accounting for the variability of uncertain parameters (such as temperature, wind, sun, water inflows) without using stochastic optimisation.
 - **Case study results:** insights about the French power mix in future years (e.g. 2030, 2050) for the four EnVis-2060 scenarios

8.3. Implementation

The simulations were conducted with the plan4res model. plan4res is an electricity system optimisation and simulation tool, composed of the following three models:

1. **A Capacity Expansion Model (CEM)** aimed at adapting the electricity mix.
2. **A Seasonal Storage Valuation model (SSV)** aimed at optimising the management of seasonal storages. It computes the Bellman values (= cost-to-go functions) that represent the future expected economic value of the seasonal storages' levels at time stages. This is necessary to know when to best use a "free" but limited and uncertain resource. For example, water inflows to large hydropower reservoirs: should the hydropower plant produce now and discharge part of its stored water, e.g. to avoid starting up a costly coal plant to meet demand, or should water be kept for a latter use, e.g. because present demand is low and RES generation is sufficient?
3. **A Simulation Model (SIM)** aimed at optimising the short-term operation of the system. The simulation is run sequentially for the entire period on every scenario using a Unit Commitment (UC) model. The cost-to-go functions computed by the SSV are used as a variable cost for the generation of seasonal storages.

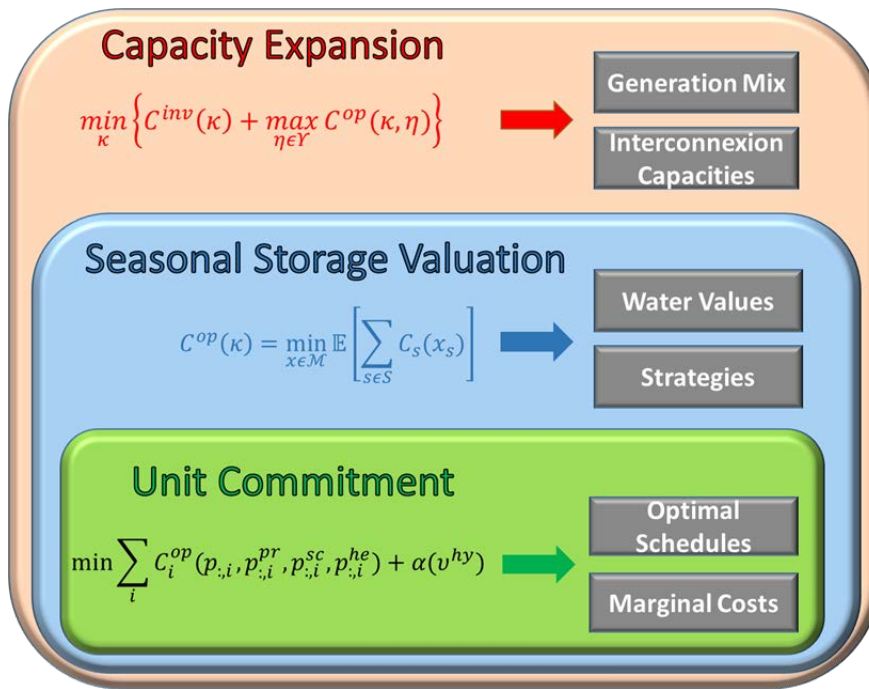


Figure 8.1. the plan4res embedded models.

As depicted in Figure 8.1, the aforementioned three models cannot be described independently as:

- The CEM uses the SSV model for the evaluation of its operation cost function, which include the economic values and opportunities offered by seasonal storages.
- The SSV model itself uses the UC model for solving its inner transition problem. Indeed, to assess the value of storages on the long run, the model sequentially computes future cost-to-go functions that represent how much a given amount of energy storage can reduce future operation costs (e.g. by using hydropower to save on expansive fuel costs). To do so, a lot of UC problems are solved recursively using an algorithm called dynamic programming.

All models share the exact same set of data, as summarised in Figure 8.2.

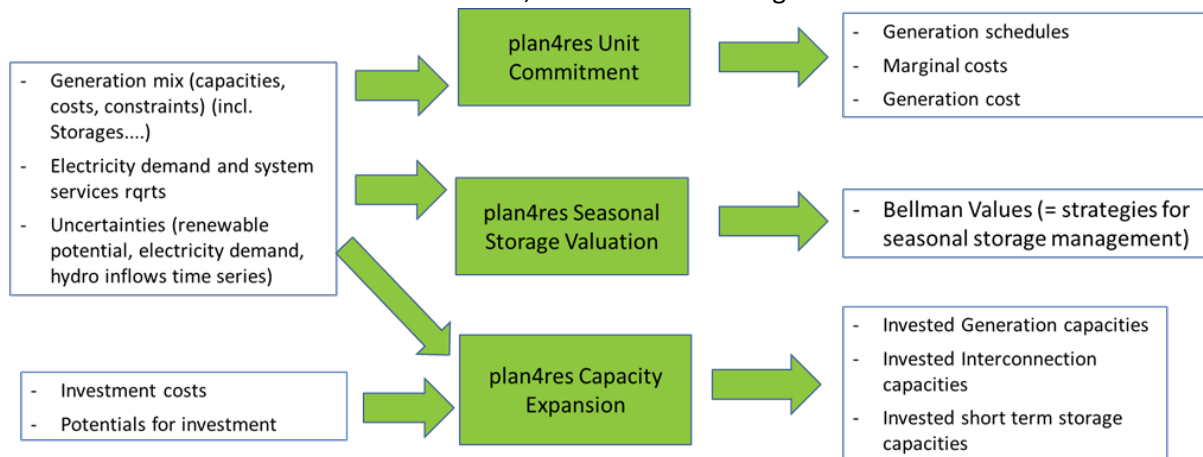


Figure 8.2. plan4res Inputs and outputs.

8.3.1. Challenges

The main challenges consisted in

- Comparing the NECP Scenario with the real NECP, where the main difficulty lies in identifying the correspondence between the different variables and recalculating equivalent ones.
- Computation of the necessary variables for feeding plan4res out of the inputs and outputs of GENeSYS-MOD. For this, we implemented a “*linkage*” script, which converts GENeSYS-MOD inputs/outputs in native format into a dataset in the IAMC format, only focusing on electricity variables. Some difficulties lie in computing the installed capacities with relation to the fuel used.

8.3.2. Mitigation Measures

The following data are required for conducting the plan4res runs:

- Electricity demand projections for all EU countries, separated into uses (heating, cooling, transport, other)
- Electricity generation technologies costs (OPEX and CAPEX)
- Electricity generation technologies characteristics (installed capacities, constraints, etc.)
- Electricity storages characteristics
- Renewables potentials and profiles
- Demand flexibility potentials for each day of a representative year. (from DATACELLAR)
- Transmission grid

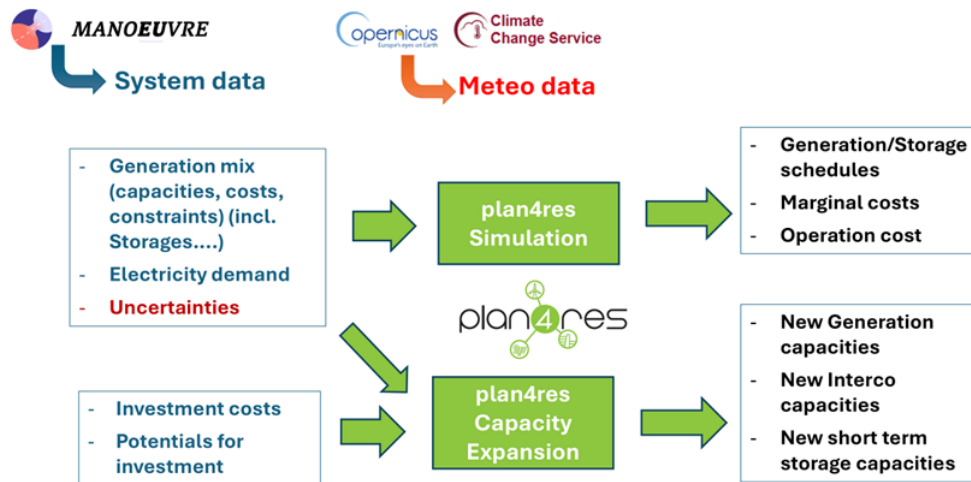


Figure 8.3. plan4res inputs and outputs and where they come from

The following subsections detail the input data per data source.

Data from EnVis Scenarios

The following variables, as defined by the open ENTRANCE nomenclature, are required. They have been created out of GENESYS-MOD raw inputs and outputs by using a linkage script for converting the data and computing variables, which are not available in the scenarios.

The following countries were used: Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Non-EU-Balkans, North Macedonia, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, The Netherlands, Turkey, United Kingdom.

The following countries are aggregated in regions:

- Belgium, Luxembourg, Netherlands → Benelux
- Estonia, Latvia, Lithuania → Baltics
- Non-EU-Balkans, Bulgaria, Croatia, Greece, Romania, Slovenia, North Macedonia → Balkans
- Austria, Czech Republic, Hungary, Poland, Slovakia → Eastern Europe

The list of variables is the following:

- **For creating the electricity demand: yearly electricity demand per uses; in TWh**
 - o Final Energy|Electricity,
 - o Final Energy|Electricity|Heat,
 - o Final Energy|Electricity|Transportation
- **For describing the transmission grid: interconnection capacities between countries (in MW)**
 - o Network|Electricity|Maximum Flow
- **For creating the generation mix, definition of all generation technologies**
 - o *Thermal generation, including the following technologies:*
 - Electricity|Biomass|w/o CCS
 - Electricity|Coal|Hard coal|w/o CCS
 - Electricity|Coal|Lignite|w/o CCS
 - Electricity|Gas|Fossil|CCGT|w/o CCS
 - Electricity|Gas|Biomethane|CCGT|w/o CCS



- Electricity|Nuclear
- Electricity|Oil|w/o CCS
- Combined Heat and Power|Biomass|w/o CCS
- Combined Heat and Power|Biomass|w/ CCS
- Combined Heat and Power|Coal|Hard coal|w/o CCS
- Combined Heat and Power|Coal|Lignite|w/o CCS
- Combined Heat and Power|Gas|Fossil|CCGT|w/o CCS

The following variables are used for thermal generation:

- Capacity|<technology> → installed capacity (GW)
- Maximum Capacity| <technology> → maximum potential for new capacity (GW)
- Maximum Utilisation|<technology> → average availability in %
- Lifetime|<technology> → life duration (number of years)
- Emission|CO₂|<technology> → emission in tons of CO₂ per MWh generated
- Variable Cost|<technology> → variable operation cost in €/MWh
- Fixed Cost|<technology> → fixed operation cost in €/MW
- Capital Cost|<technology> → CAPEX in €/MW

- o *Hydraulic generation, including reservoirs (= large lakes), pumped storage and run-of river.*

The following variables are used:

- Capacity|Electricity|Hydro|Reservoir: installed capacity of hydro reservoir generation (GW)
- Secondary Energy|Electricity|Hydro|Reservoir for computing the hydraulic inflows to the reservoirs (TWh);
- Maximum Storage|Electricity|Hydro|Reservoir: size of the reservoir storages (TWh)
- Maximum Utilisation|Electricity|Hydro|Reservoir: average availability (%)
- Capacity|Electricity|Hydro|Pumped Storage: installed capacity of pumped storage generation
- Maximum Storage|Electricity|Hydro|Pumped Storage: size of storages (TWh)
- Maximum Capacity|Electricity|Hydro|Pumped Storage: maximum potential for new generation capacities (GW)
- Capital Cost|Electricity|Hydro|Pumped Storage: CAPEX (€/GW)
- Fixed Cost|Electricity|Hydro|Pumped Storage: Fixed operation cost (€/GW)
- Lifetime|Electricity|Hydro|Pumped Storage: life duration (# of years)
- Pumping Efficiency|Electricity|Hydro|Pumped Storage: efficiency of the pumped storage
- Capacity|Electricity|Hydro|Run of river: installed capacity of run of river generation
- Maximum Capacity|Electricity|Hydro|Run of river: maximum potential for new generation capacities (GW)
- Capital Cost|Electricity|Hydro| Run of river: CAPEX (€/GW)
- Fixed Cost|Electricity|Hydro| Run of river: Fixed operation cost (€/GW)
- Lifetime|Electricity|Hydro|Run of river: life duration (# of years)
- Pumping Efficiency|Electricity|Hydro| Run of river: efficiency of the pumped storage



- o *Renewable Energy Sources, including photovoltaic and wind power generation:*
 - Solar|CSP
 - Solar|PV|Rooftop
 - Solar|PV|Utility
 - Wind|Onshore
 - Wind|Offshore

The following variables are used:

- Capacity|Electricity|<technology>: installed capacity of run of river generation
- Maximum Capacity|Electricity|<technology>: maximum potential for new generation capacities (GW)
- Capital Cost|Electricity|<technology>: CAPEX (€/GW)
- Fixed Cost|Electricity|<technology> Fixed operation cost (€/GW)
- Lifetime|Electricity|<technology>: life duration (# of years)

Data representing the uncertainties

We used timeseries from the Horizon Europe CROSSEU¹⁰ project, where hourly scenarised profiles are available. These chronicles correspond to 37 climatic years.

- Hourly demand profiles are generated by multiplying the overall yearly demand by hourly rate profiles from CROSSEU (hourly profiles electricity demand for heating; electricity demand for electric mobility; (deterministic) electricity demand for other uses);
- hourly maximum generation profiles for PV, offshore/onshore wind-power and run of river hydropower are computed by multiplying CROSSEU scenarised profiles by the installed capacity.
- Inflows to reservoir profiles are generated by multiplying the overall yearly energy produced by Reservoir hydro by hourly rate profiles from CROSSEU.

8.4. Results

We present below the main results obtained by simulating the operation of the power system in France, for the year 2030 (in practice from July 2030 to June 2031), for the scenario NECP Essentials v1.3.

8.4.1. Outcomes

The Inputs for the installed capacities and demands: Figure 8.4 shows the power installed capacities in all the regions in the case study, for the year 2030, while Figure 8.5 displays the same data on a map of Europe. The installed capacities are directly derived from GENeSYS-MOD results and served as inputs to plan4res.

¹⁰ The Horizon Europe CROSSEU project: [CROSSEU - Advancing climate resilience](#)

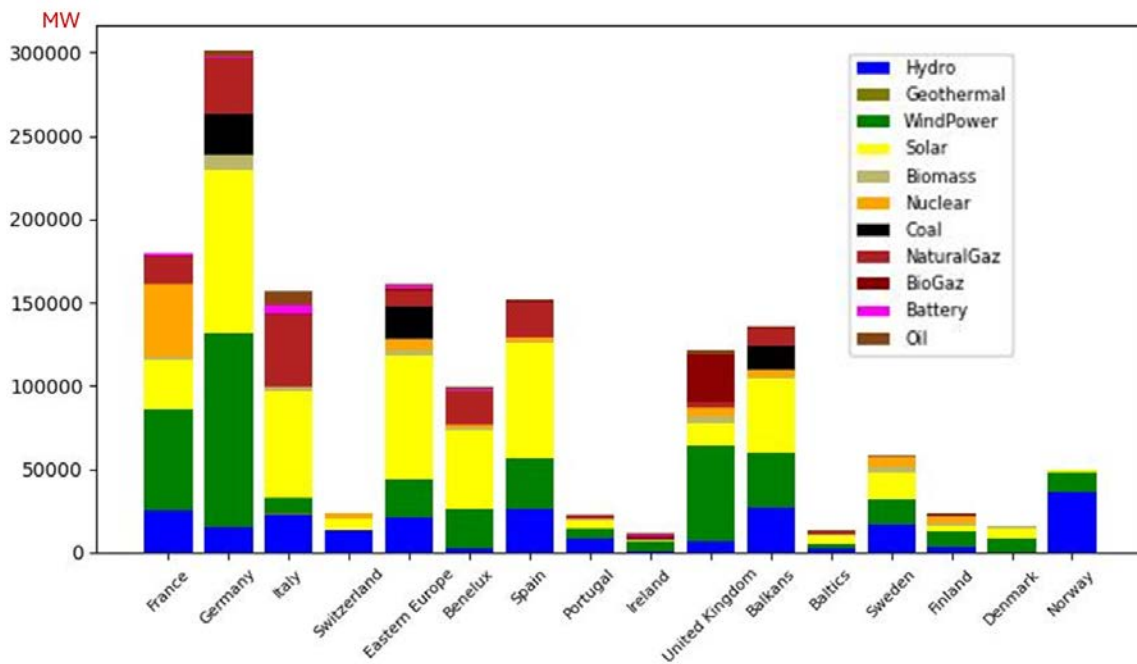


Figure 8.4. Power generation installed Capacity in NECP Essentials v1.3, 2030 (in MW)

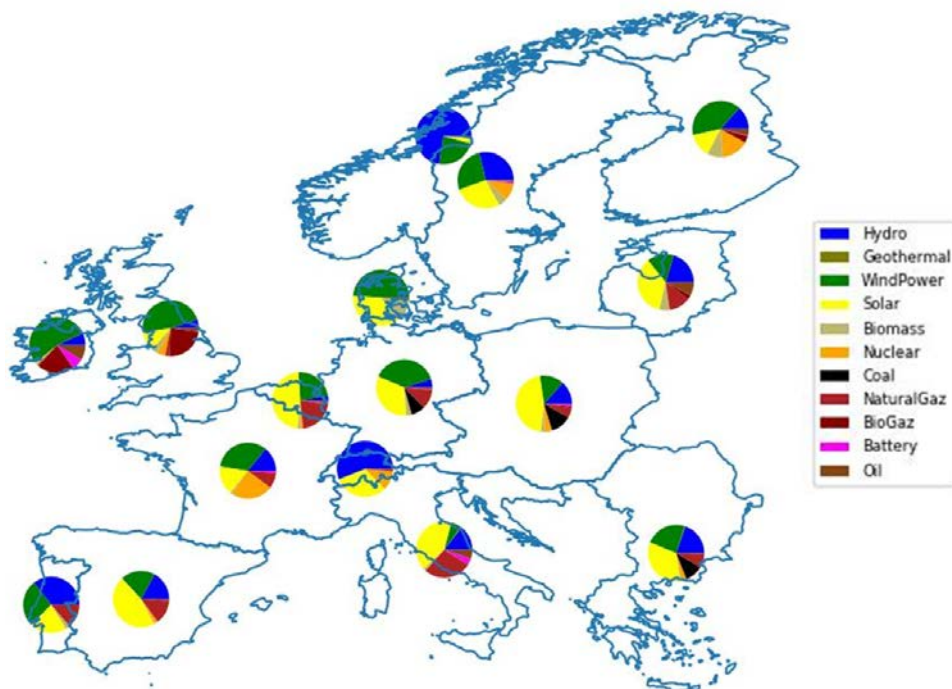


Figure 8.5. Power generation installed Capacity in NECP Essentials v1.3, 2030 (shares).

Figures 8.6 and 8.7 show the interconnection capacities, which are also a result of GENeSYS-MOD and inputs to plan4res.

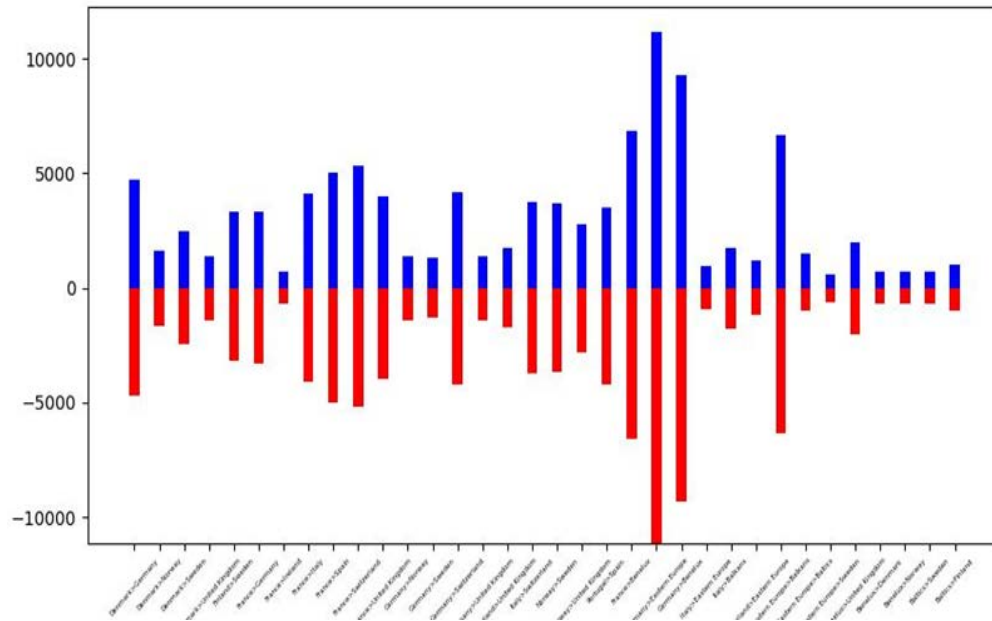


Figure 8.6. Interconnection capacities between regions (in MW)

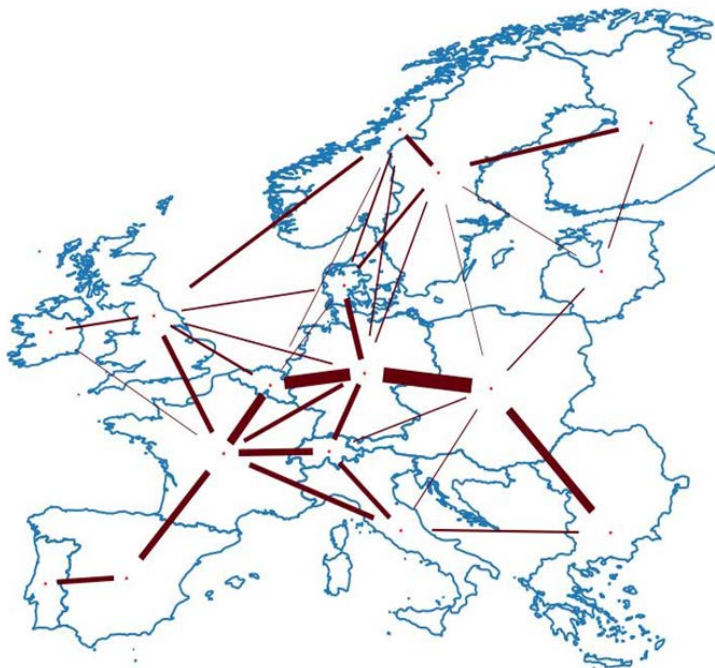


Figure 8.7. Map of interconnection capacities

Figure 8.8 depicts the power demand timeseries, which were computed by multiplying the total power demand (i.e. Final Energy|Electricity) for the year 2030 from GENeSYS-MOD by scenarised hourly profiles of the power demand from the CROSEU project, based on ERA5 climate projections. In the case study, 105 timeseries (for each region) are employed. Those timeseries, which are also correlated with timeseries for the load factors of renewable generation and inflows to hydro reservoirs, represent climate variabilities.

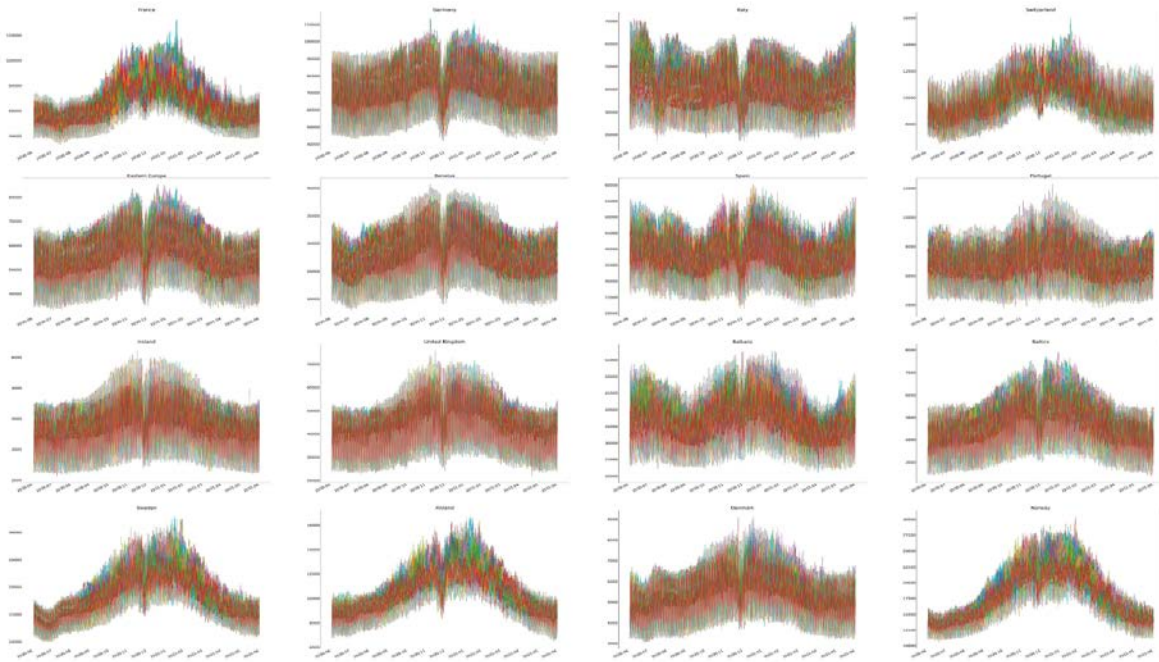


Figure 8.8. Scenarised power demand timeseries between Jul1,2030 and June30, 2030 (in MWh).

Analyses on the whole year 2030: Figures 8.9 and 8.10 show the average yearly power production, which is computed by plan4res, as an average over the 105 climatic scenarios.

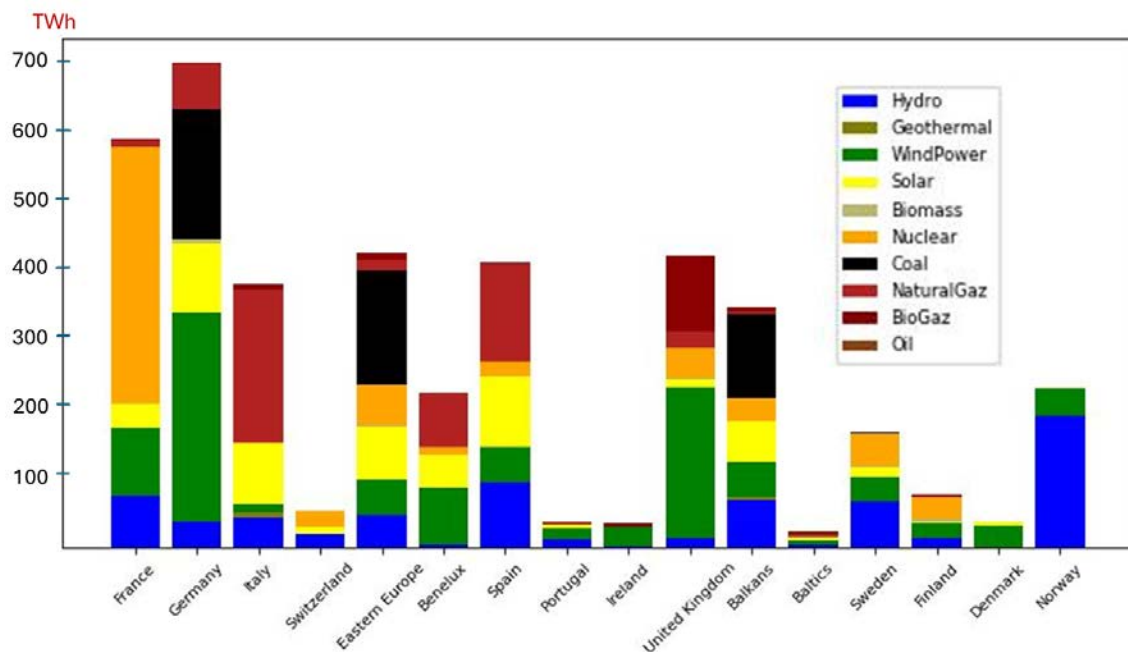


Figure 8.9. Average yearly power production per technology (in TWh).

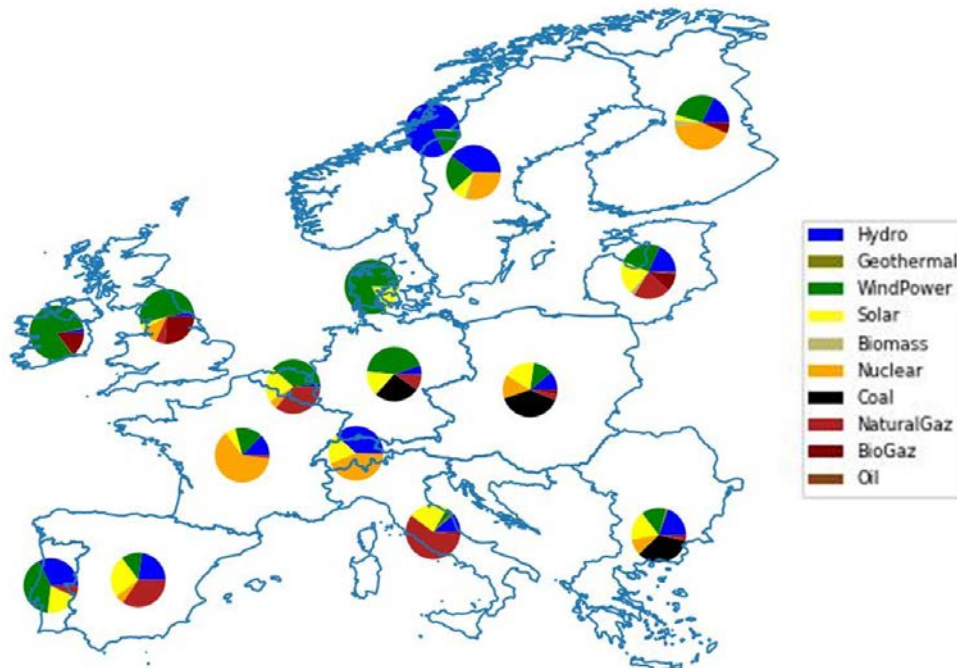


Figure 8.10. Map of the shares of power production per technology.

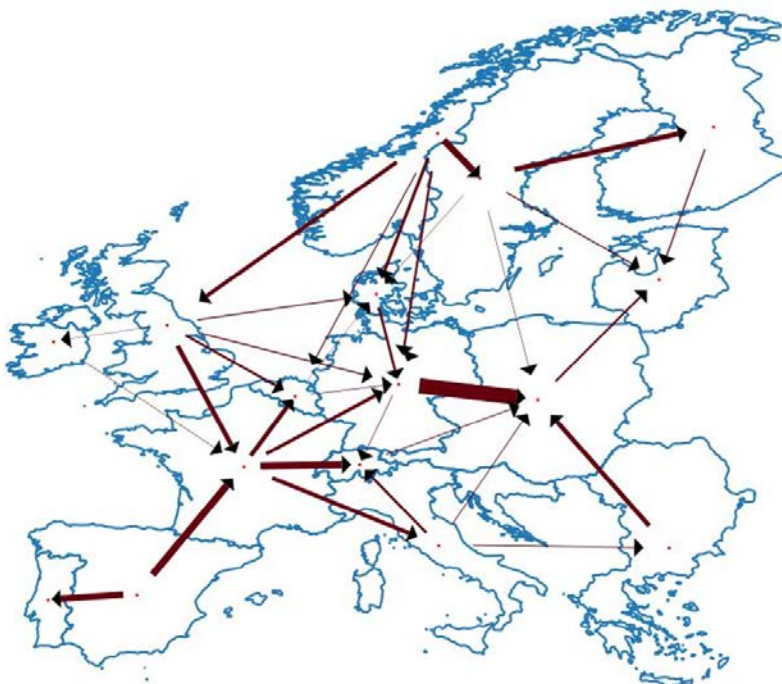


Figure 8.11. Average power flows between regions.

Figure 8.12 shows the marginal costs of electricity in selected regions for all scenarios. The costs are ordered from highest to lowest to help the reader visualise the differences.

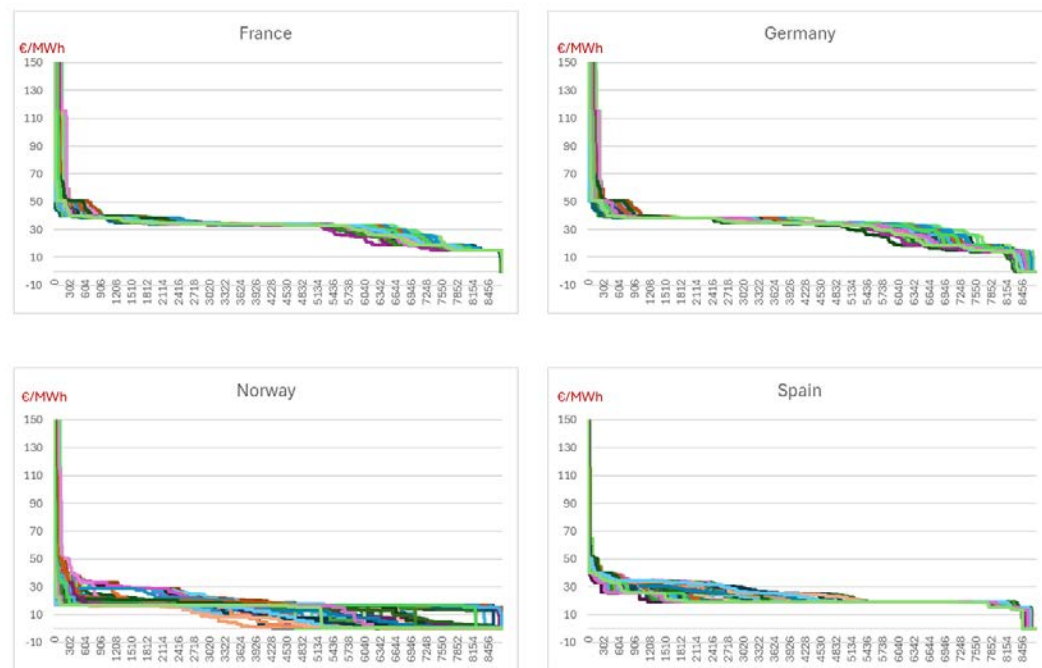


Figure 8.12. Histogram of the scenarised marginal costs of electricity (€/MWh).

Figure 8.13 shows the scenarised schedules of non-served electricity, for a selection of countries, while Figure 8.14 exhibits the average number of hours in the year with non-served electricity as well as the maximum (corresponding to the scenario with the biggest number of hours). Figures 8.15 and 8.16 show the amplitude of the non-served electricity.

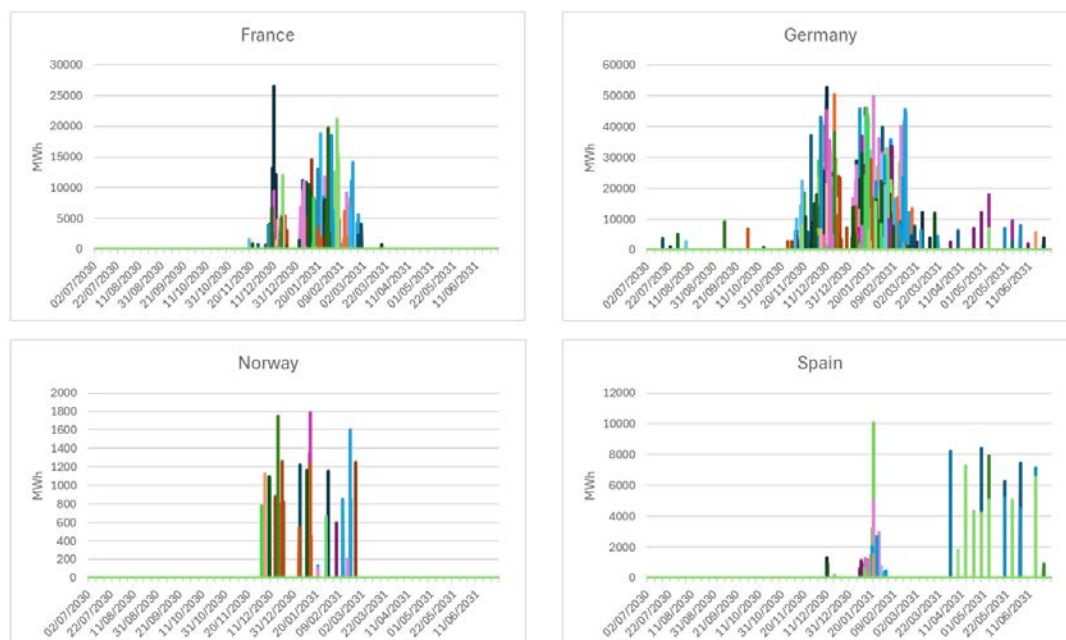


Figure 8.13. Scenarised schedules of non-served electricity (MWh).

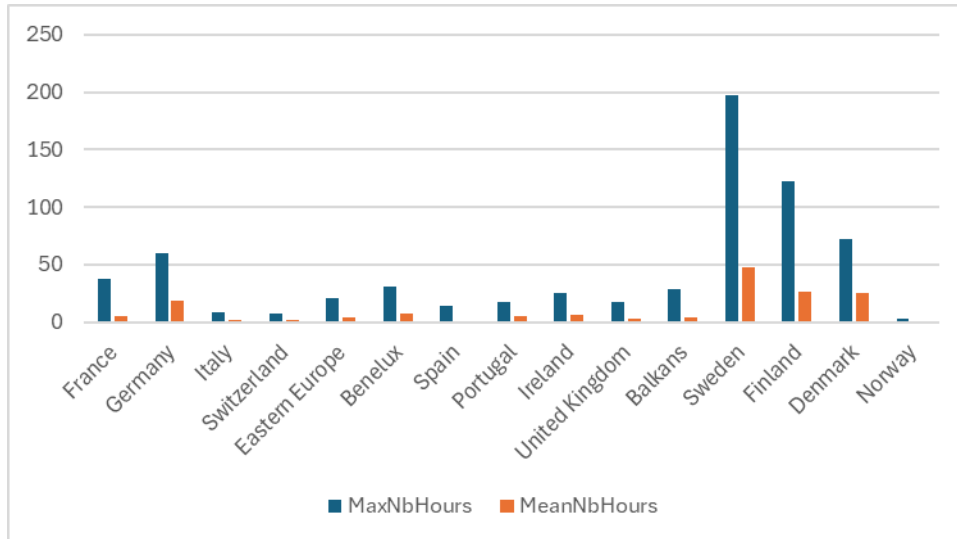


Figure 8.14. Maximum and average number of hours with non-served electricity.

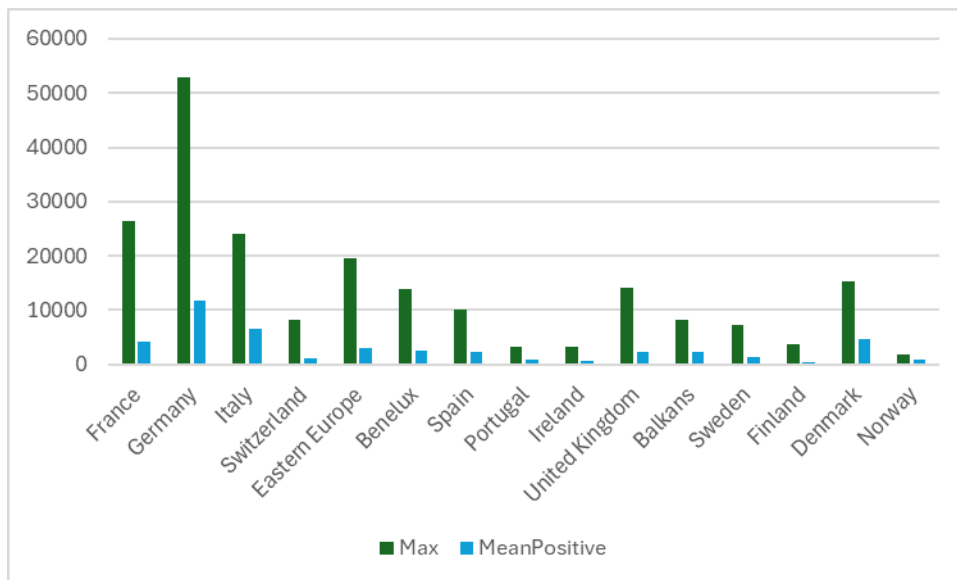


Figure 8.15. Maximum and average value of hourly non-served electricity (MWh).

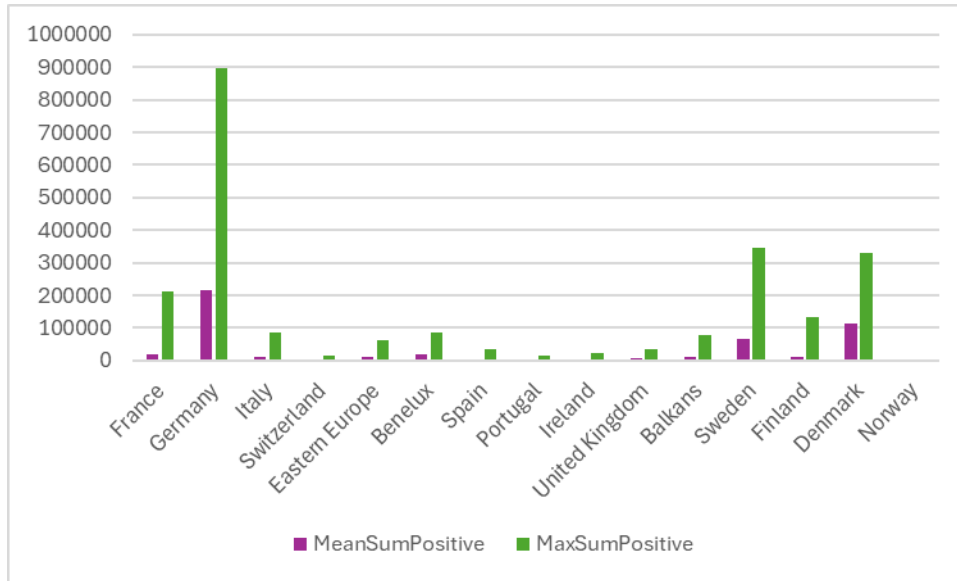


Figure 8.16. Maximum and average (over the 105 scenarios) value of the total non-served electricity on whole year (MWh).

Figure 8.17 shows the power generation from the available technologies during the whole year (from July to June). The graph on the top represents the climatic Scenario 31, which is an average scenario, with no non-served electricity, while the graph on the bottom is scenario 13, characterised by a high number of hours with non-served electricity, including a period of 6 consecutive hours. It includes a period with a very high demand peak (the black line corresponds to the power demand), and low wind power generation.

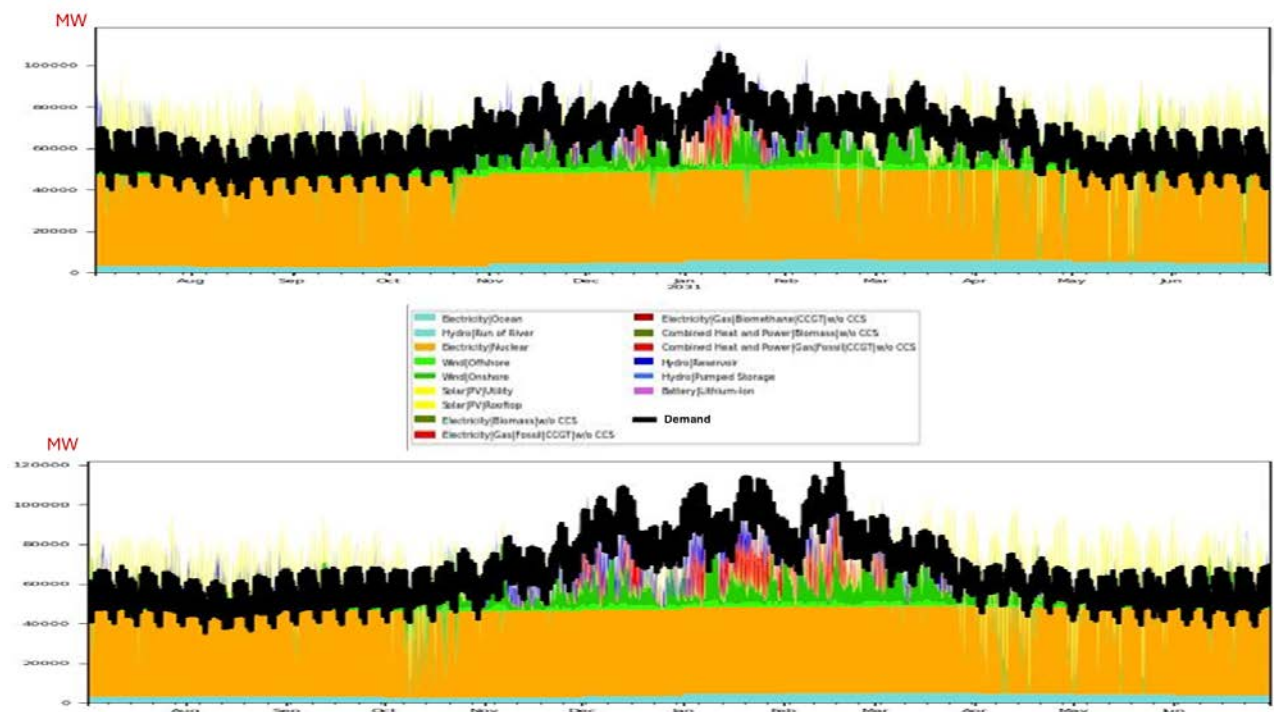


Figure 8.17. Stacked power generation in France 2030, for two different uncertainty scenarios



Focus on a difficult winter period: Figure 8.18 zooms on the power demands between January 22 and January 28.

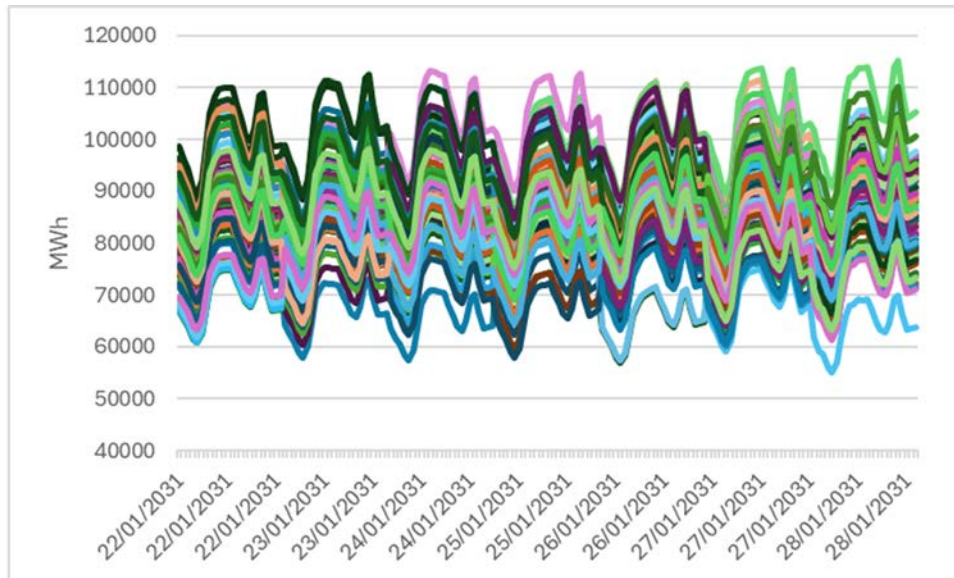


Figure 8.18: Scenarised demands in France from Jan 31 to Feb 13.

The following analysis examines the optimised power generation schedules and marginal costs for two scenarios: Scenario 13, which represents one of the most challenging cases with the highest non-served electricity and demand, and Scenario 31 (light blue), which serves as an average scenario.

Figure 8.19 depicts the stacked schedules of power generation for one winter week in France. The left side shows scenario 31, an average scenario without non-served electricity, while the right side shows scenario 13, which has higher demand and lower wind power during the first days. The difference between generation and demand represents imports and exports. On the right-hand side, there is less hydropower usage, reflecting the fact that this scenario represents a dry year. Consequently, peak gas power (red colour) is used instead.

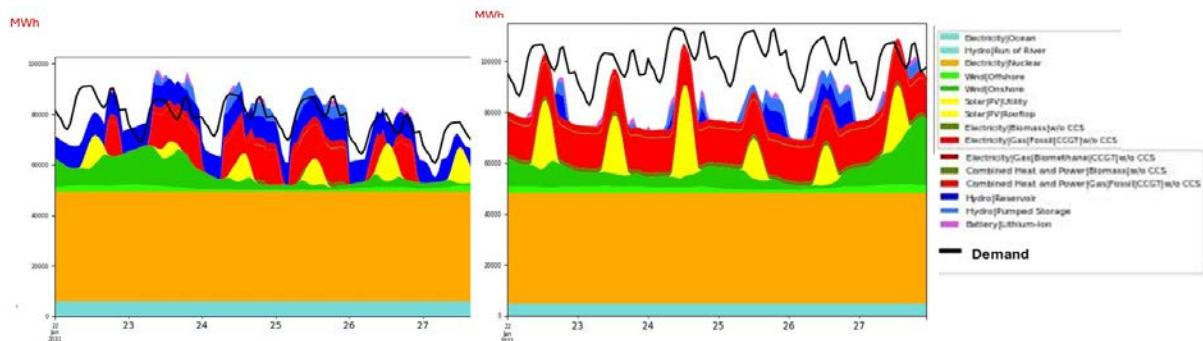


Figure 8.19. Power generation (in MWh), for one winter weeks in France, Scenarios 31 (left-side) and 13 (right-side).

Figure 8.20(a) shows the non-served electricity, which occurs only in scenario 13, while Figure 8.20(b) shows the marginal costs, which are much higher in scenario 13 than in scenario 31.

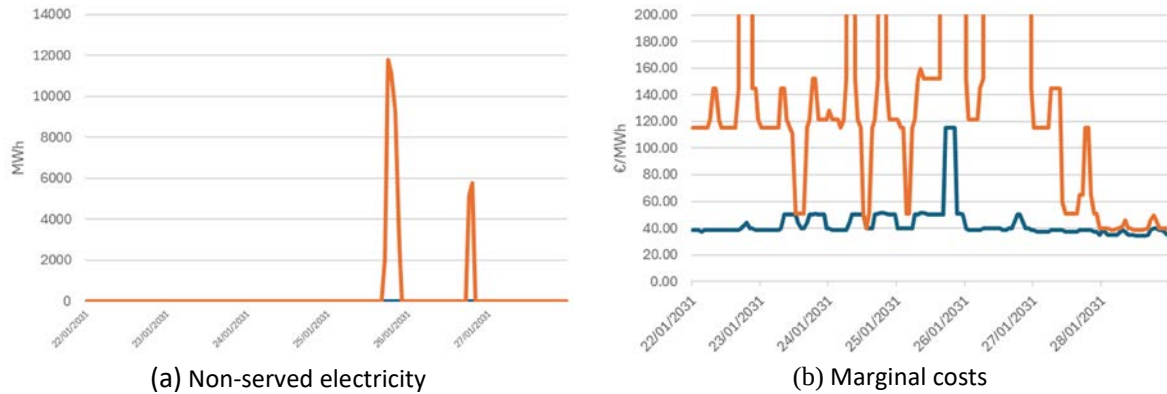


Figure 8.20. (a) Non-served electricity, and (b) Marginal costs for one winter weeks in France, Scenarios 31 (blue) and 13 (orange).

8.4.2. NECPs

We conduct here a comparison of the EnVis-2060 NECP Essentials scenario (v1.3) with the actual NECP for France. The objective was to adapt the inputs of GENeSYS-MOD so that its outputs, regarding the NECP Essentials scenario, are reasonably in line with the French NECP. This comparison enabled us to identify the main divergences and to propose measures to mitigate them:

1. The sectoral consumption as modelled in GENeSYS-MOD needs to be adapted (see Figure 8.21):

- The consumption of the industry sector is under-estimated
- The consumption of the residential sector is slightly under- estimated
- The power consumption for specific uses of electricity is over-estimated

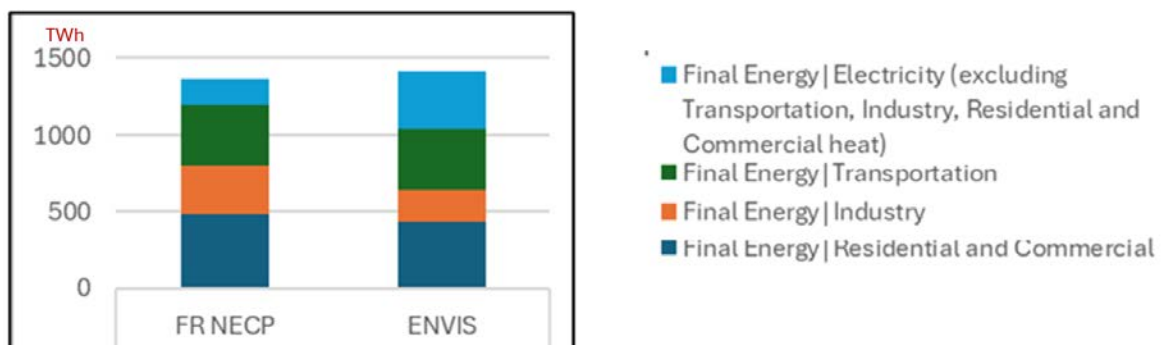


Figure 8.21. Final energy per sector (in TWh)

2. The weight of the different energy vectors needs to be adapted (see Figure 8.22 and 8.23):

- The gas consumption is over-estimated, especially in the building sector (see Figure 8.22)
- While the power consumption is under-estimated

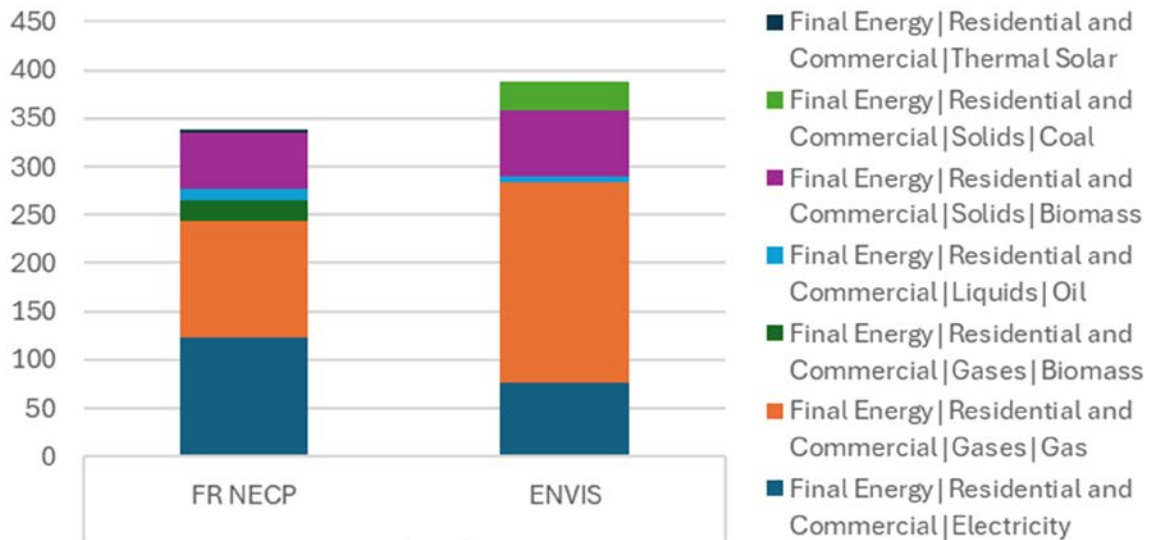


Figure 8.22. Final energy of the building sector, per energy vectors (in TWh)

- c. The coal consumption is over-estimated
- d. The gas consumption is over-estimated

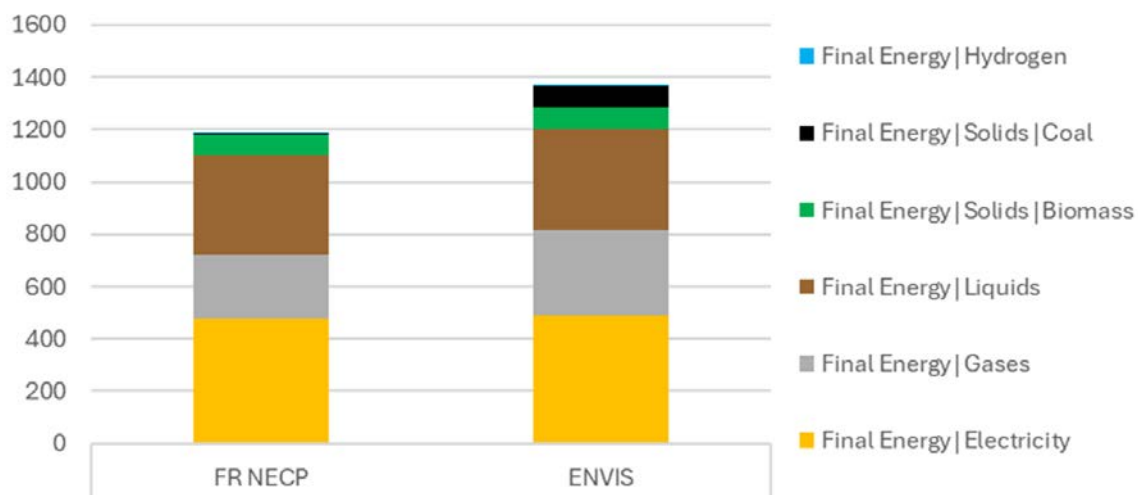


Figure 8.23. Final energy per energy vector (in TWh)

3. **The electricity generation (see Figure 8.24) is reasonable, with a few divergences:**
 - a. The French NECP foresee shutdown of coal-fuelled generation in 2027, while it remains in GENE SYS-MOD until 2050
 - b. Gas-fuelled generation is over-estimated
 - c. Oil-fuelled generation is over-estimated

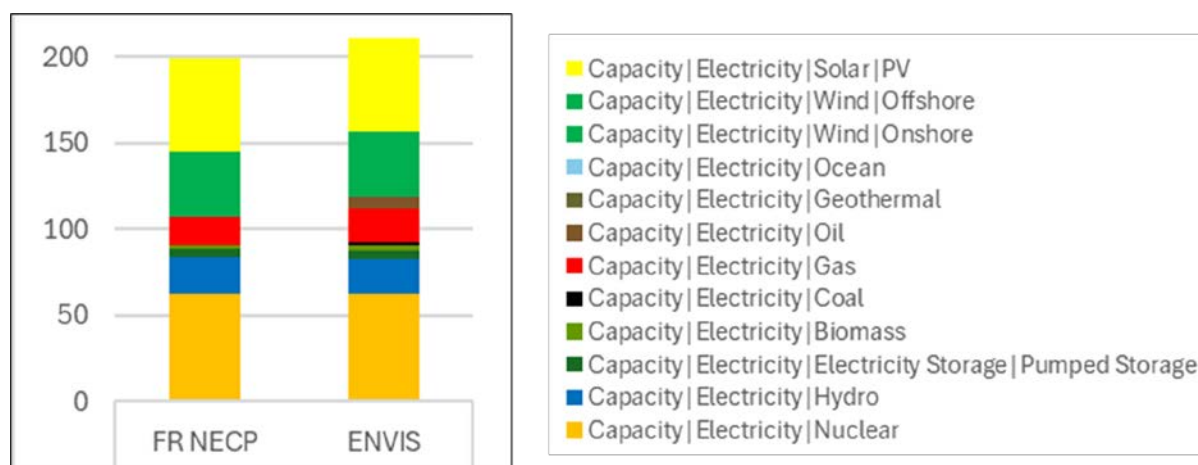


Figure 8.24. Electricity generation installed capacity (in GW)

4. Electrification of uses is highly under-estimated in all sectors, but particularly in the industry sector, where it is “replaced” by coal and gas (see Figure 8.25)

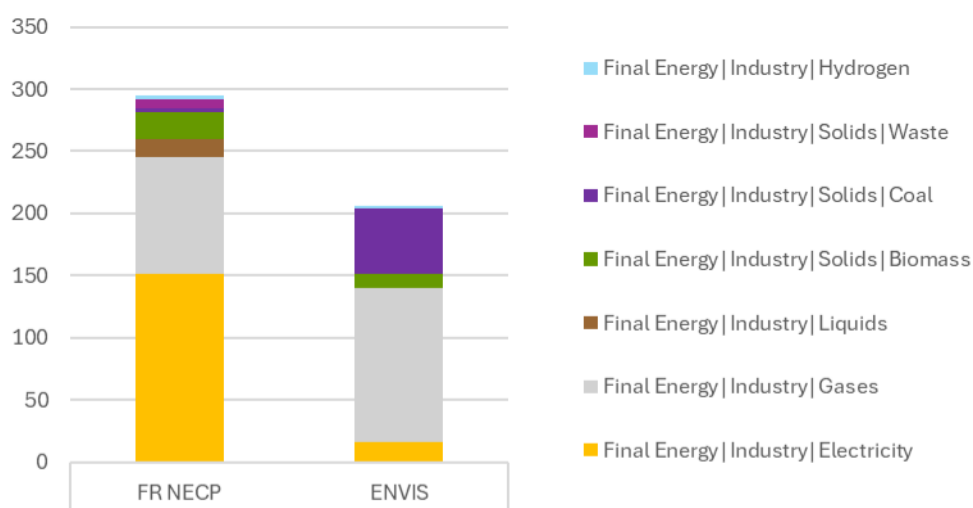


Figure 8.25. Final energy per energy vector in the industry sector.

8.4.3. Supplementary Data

The data used to compare the NECP with the EnVis-2060 NECP Essentials scenario are based on the modelling exercises published by the French Ministry for Ecological Transition, which also form the foundation for the NECP’s development. The details are available on the ministry’s web site¹¹.

The scenarised timeseries have been created by the CROSSEU project, based on the latest data available in the Pan-European Climate Database, which provides information on climate and renewable energy variables for both historical and future time periods. For historical data, the ERA5 global reanalysis serves as the underlying climate data, while future projections are based on selected CMIP6 global climate models. More details can be found on the Copernicus Climate Data Store¹².

11 [Scénarios prospectifs énergie-climat-air | Ministères Aménagement du territoire Transition écologique](#)

12 [Climate and energy related variables from the Pan-European Climate Database derived from reanalysis and climate projections](#)

**Case study results:**

Plan4res source code is available in the plan4res GitHub: <https://github.com/plan4res>

The results of the plan4res runs for the ENVIS60 NECP Essentials v1.3 for year 2030 are available on Zenodo: <https://zenodo.org/records/19253308>

Case study 9: Power Market Modelling: Spain and Portugal

This case study meticulously addresses the 2030 NECP of Portugal (version 2024), which has the ambitious goal of increasing the penetration of renewables in the electric sector to a share of 87% by 2030 (Direção-Geral de Energia e Geologia, 2024). This target can be achieved by increasing the capacity of wind (to 9.3 GW), solar PV (to 9.0 GW), hydro (8.7 GW, of which 4.1 GW will be PHS – pump hydro storage), and biomass (to 0.5 GW). Combined Cycle Gas Turbine (CCGT) is already the only fossil-fuel technology in operation in Portugal since 2021, as all coal plants were decommissioned.

Case Study 9 simulated the power and energy markets in Portugal. Since Portuguese and Spanish electricity markets are integrated within the Iberian region, the Spanish NECP has also been considered in a more general form. Furthermore, both countries are expected to increase their cross-border transmission capacity from the actual 3.2 GW to 4.2 GW in 2030. Within the context of REPowerEU, Portugal is particularly focussed on accelerating variable Renewable Energy Source (vRES) power plants deployment via simplified permitting processes, exploring new concepts as RES hybrid power plants, and on implementing renewables gases generation and consumption (green hydrogen and biomethane). Therefore, this case study has paid special attention to these factors, particularly by considering different types of Power Purchase Agreements (PPAs) and their smooth integration into the energy market via proposing solutions to mitigate bottlenecks of these trading contracts, allowing citizens and industry to access affordable and clean renewable-based generation.

It is also widely discussed how and why the traditional centralised top-down approach of electricity/energy markets has proven to be insufficient to gather the full potential of consumers, variable renewable energy sources, and the synergy with other energy vectors (Algarvio et al., 2024). The fact that future markets will drive and efficiently coordinate all elements of the power system (i.e. generation, consumption, storage and other flexibility options), from individual consumers to the wholesale level, results in a pressing need to study, implement and test new market models/designs and tools. Consequently, the investment in projects related to this subject is increasing significantly, particularly in Europe.

Case study 9 combined expertise on both power market modelling with energy system modelling, investigating synergies and antagonisms between these two analytical levels. We also assess the operation of Iberian electricity market (i.e. MIBEL) and provide recommendations for the 2030 Portuguese NECP. Figure 9.1 schematically presents the soft-linking approach of various tools employed in CS9, highlighting the types of simulations and the objectives of each simulation.

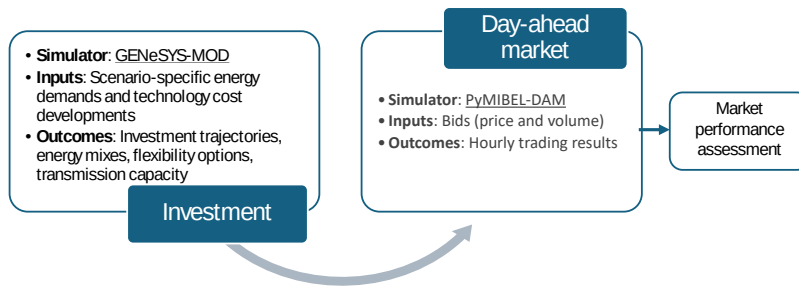


Figure 9.1. Overview of the soft-linking procedure for simulated the day-ahead market in Case Study 9.

9.1. Accomplished Tasks

Task 9.1 – Collecting, analysing and selecting data: This task focuses on gathering and analysing data essential for accurately modelling the Iberian electricity market. A key objective is to ensure that the selected data has the appropriate temporal and spatial resolution to effectively replicate market behaviour, including electricity generation, demand patterns, cross-border exchanges, and pricing dynamics. The process started with the collection and analysis of relevant Iberian governmental plans, such as the 2030 Portuguese NECP (version released in 2024) and carbon-neutral roadmaps, to identify strategic targets, regulatory frameworks, and expected market developments. Based on this analysis, a careful selection of data has been made to ensure consistency and reliability in subsequent simulations.

Data from the WP2 scenarios is also considered to simulate various future energy mixes, where applicable and in alignment with established national commitments.

Task 9.2 – Modelling, parametrisation and simulation: The focus is on modelling and simulating the electric power sub-system, including the development and integration of dispatching capabilities and sub-models into existing electricity market models. This task involves parameterising all necessary input data to simulate the most relevant Iberian/Portuguese scenarios defined within the project. The PyMIBEL-DAM - *MIBEL Day-Ahead Market Simulator* (Couto et al., 2025) and *RES.Trade* (Algarvio et al., 2024) models have been developed and enhanced to improve the accuracy and reliability of the studies. Additionally, the adoption of a dispatch programming model (e.g. Dispa-SET¹³ or PyPSA¹⁴) were considered to simulate the hourly commitment of different power plants in Portugal, ensuring a more detailed representation of market operations.

Further system improvements have been implemented to optimise simulations, followed by initial analysis of results, which guides updates and refinements in the modelling approach. The enhancements support the comprehensive analysis of results, supporting updates in modelling and simulations that align with the project's objectives.

Task 9.3 – Recommendation to the Portuguese NECP: This final task involves an in-depth analysis of the project results to develop and provide comprehensive recommendations for the Portuguese NECP, focusing particularly on the electric power sub-sector. The recommendations address key aspects of the electric power system, offering guidance on optimising its performance, aligning with national energy objectives, and supporting the transition to a sustainable and resilient energy future

¹³ see <https://www.dispaset.eu> (accessed on 30 March 2026).

¹⁴ see <https://pypsa.readthedocs.io/> (accessed on 30 March 2026).



for Portugal. These findings also support the refinement of the models and simulations, ensuring that the recommendations are based on accurate, up-to-date data and models.

9.2. Planned impact

Given the ambitious renewable energy targets outlined in the recent version of the Portuguese 2030 NECP, understanding the operational feasibility of this scenario becomes crucial. While the long-term energy system models used to define these targets are fundamental for establishing pathways and investment needs, they often lack the temporal and technical resolution required to capture short-term system dynamics and operational constraints. To complement these strategic planning models, running a dispatch model, such as Dispa-SET, is therefore essential. This type of model simulates the hourly operation of the power system, considering generation profiles, demand variations, and flexibility solutions. Using this approach makes it possible to identify bottlenecks in system flexibility, evaluate the adequacy of storage and backup capacity, and estimate system costs and emissions with higher accuracy.

In this context, in the first step, assuming an isolated system without interconnection to Spain, the dispatch simulations serve as a feasibility check of the NECP ambitions, bridging the gap between the policy targets and the physical realities of power system operation. The insights obtained serve as a benchmark, to be later compared with the results from WP2, and will support policymakers and stakeholders in designing robust, cost-effective, and secure energy transition strategies, ensuring that the renewable integration goals are both technically feasible and economically sustainable.

The second step uses the hourly market clearing through linear programming, explicitly incorporating supply and demand bids. GENeSYS-MOD (v1.2) is used to simulate investment decisions, while PyMIBEL-DAM¹⁵ simulates the hourly day-ahead electricity market clearing for the MIBEL, implemented using PyPSA - Python for Power System Analysis (Brown et al., 2018).

9.3. Implementation

The implementation approach of this case study relies in two main tools. All tools required further development and adaptation for the project.

- The Dispa-set model from the Joint Research Center - a high-resolution energy system modelling tool developed by the Joint Research Centre from European Commission, applied to Portugal to analyse regional energy demand, supply, and integration scenarios, supporting national energy planning and policy decisions.
- PyMIBEL-DAM is a simulation tool for the day-ahead electricity market of the Iberian Electricity Market, developed using PyPSA. This tool was developed within the ManOEUVRE project and validated using the results from (Algarvio et al., 2025; Estanqueiro et al., 2024). The tool simulates the hourly market clearing through linear programming, explicitly incorporating supply and demand bids. The model considers the interconnection capacity between Portugal (PT) and Spain (ES) and produces key outputs, including zonal prices, traded energy volumes, and interconnection flows. By reproducing the fundamental economic clearing logic of the MIBEL DAM, the tool provides a transparent and computationally efficient framework for market analysis.

¹⁵ see <https://github.com/AntCouto/PyMIBEL-DAMSimulator> (accessed on 30 March 2026).



These models are fed by data from NECP and from the investments in GENeSYS-MOD (from WP2) that provides key information, such as optimal capacities per power plant, power plant efficiency, fixed and variable costs, and potentially sector coupling capacities.

9.3.1. Challenges

Most of the data from the NECP and GENeSYS-MOD is only available at an aggregated national level, and with a coarse temporal resolution, limiting our ability to accurately replicate competitive market behaviour. This lack of granularity prevents a detailed representation of the different generation profiles of vRES and does not reflect the strategic behaviour of market participants. For example, WP2 results (for Portugal) indicate no installed electrolyzers or battery systems and even the decommissioning of wind power capacity in the different scenarios for 2030, which contrasts with the NECP projections. These differences can be explained mainly by two factors:

- i) the European-scale optimisation applied in WP2, which leads to a higher deployment of solar capacity in Portugal due to its highest capacity factors; and
- ii) the assumed interconnection capacity, since the Portuguese NECP considers an isolated system without interconnection with Spain, while WP2 accounts for a fully interconnected European grid.

9.3.2. Mitigation Measures

To address the coarse spatiotemporal data limitation, data from multiple wind and solar PV power plants in Portugal and Spain are used and proportionally scaled up to match the installed capacity in each scenario. This approach ensures the inclusion of vRES players with diverse generation profiles, enabling a more realistic representation of bidding strategies in the MIBEL electricity market.

Given the significant discrepancies between the WP2 outcomes and the Portuguese NECP, first, the analysis focused on the most recent version of the Portuguese NECP, namely, in the assessment of the impact of flexible solutions, such as hydrogen production, energy storage, and demand flexibility, in Portugal, which represent key components of the future MIBEL market. Then, we concentrate on the evaluation of the performance of the MIBEL's day-ahead market from 2030 to 2050 using the results of the GENeSYS-MOD model.

9.4. Results

In this section, results using the: i) Dispa-set model for Portugal and ii) GENeSYS-MOD and PyMIBEL-DAM soft-linking are used complementarily to assess the impact of future energy scenarios in MIBEL are presented.

9.4.1. Outcomes

Assessment of the impact of flexible solutions using the NECP 2030 (version 2024)

Table 9.1 provides the installed capacity according to the Portuguese NECP 2030. According to the table, the total installed capacity is expected to reach nearly 48 GW, with vRES (e.g. wind and solar PV) reaching 33.2 GW, representing a 69% share of the total installed capacity. Including hydro, biomass, and other renewables, renewable sources represent 89% of total capacity, highlighting a highly decarbonised and renewable-based power system.



Table 9.1. Technologies and installed capacity foreseen for 2030.

Technology	Installed capacity (GW)
Hydro (Pumped hydro storage)	8.1 (3.9)
Wind (onshore / offshore)	12.4 (10.4 / 2.0)
Solar PV (centralised/ decentralised)	20.8 (15.1 / 5.7)
Biomass, Biogas and Wast	1.3
Other renewables	0.3
Natural Gas	3.5
Batteries	2.0
Total	48.4

Based on the last version, the total electricity consumption in Portugal is expected to reach approximately 90 TWh. This high demand is justified by two main factors: **i)** the additional electricity needs of the industrial sector due to digitalisation and energy transition, including adoption of low-carbon technologies and smart manufacturing processes. To account this increment, the consumption time series from Helistö et al. (2024) was used; **ii)** the planned electrolyzers installed capacity of around 3 GW, which alone will be an important consumption of electricity since to ensure economic viability this technology should have a capacity factor ideally equal to or above 75%. In the simulations, the electricity consumption of the electrolyzers is not predefined. The model autonomously decides whether and when the electrolyzers operate based on system conditions.

Based on the data presented in the Portuguese NECP, a series of simulations was carried out to assess the impact of different flexibility solutions. Table 9.2 summarises the simulation configurations performed with the Dispa-SET model, assuming the installed capacities from Table 9.1 while considering typical operational efficiencies, constraints and cost parameters available in the literature for Portugal as well as the data (renewable generation and demand) from 2019.

Table 9.2. Technologies and installed capacity foreseen for 2030.

Scenario	Installed capacity (GW)		Batteries storage (h)	Demand flexibility (%)
	Batteries	Electrolysers		
Baseline	2	3	8	0
Bat_4h	2	3	4	0
Bat_2h	2	3	2	0
H2_1GW	2	1	8	0
H2_5GW	2	5	8	0
DemFI_5%	2	3	8	5
DemFI_10%	2	3	8	10

According to Table 9.2, the simulations designed to assess the impact of different flexibility options on the power system include a *baseline* scenario with 2 GW of batteries (comprising 4 units of 500 MW each in all scenarios) with 8 hours of storage and 3 GW of electrolyser capacity, and no demand flexibility. Battery storage scenarios (*Bat_4h* and *Bat_2h*) test shorter storage durations, while

electrolyser scenarios (*H2_1GW* and *H2_5GW*) assess the effects of hydrogen consumption on system flexibility. Demand flexibility scenarios (*DemFI_5%* and *DemFI_10%*) evaluate the benefits of shifting 5% and 10% of consumption, respectively, to better align demand vRES generation.

Figure 9.2 shows the representative first week of simulation for the *Baseline* and *Bat_2h* scenarios. From this figure, it is possible to observe the role of battery storage in meeting electricity demand at the end of the day, which in the *Bat_2h* scenario largely replaces the generation that would otherwise be supplied by gas power plants.

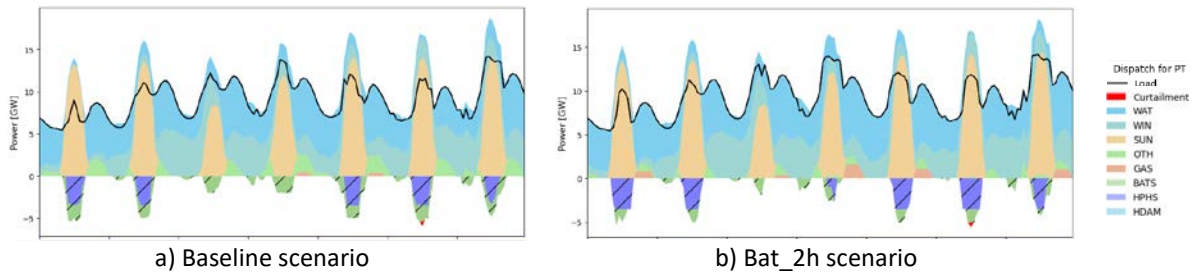


Figure 9.2. Representative first week of simulation.

To better understand the patterns of electricity generation and storage operation, Figure 9.3 presents an annual heatmap for the *Baseline* and *Bat_2h* scenarios, highlighting the contribution of each technology during the year.

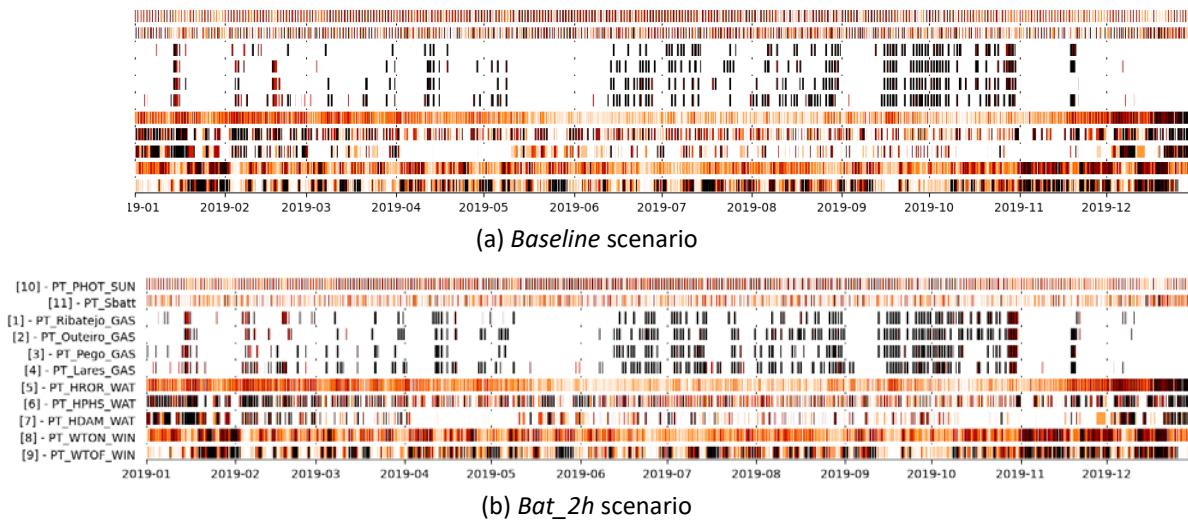


Figure 9.3. Annual heatmap of hourly generation.

Renewable generation penetration and curtailment: The annual share of vRES and RES penetration in the final electricity consumption is depicted in Figure 9.4.

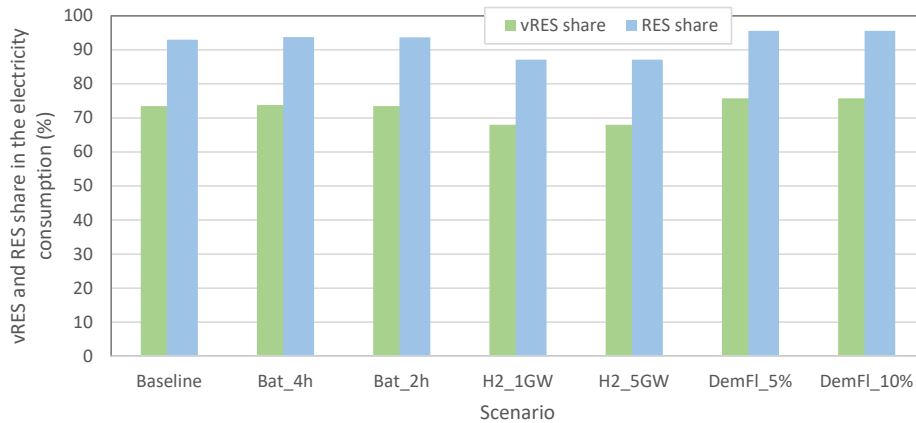


Figure 9.4. Annual share of vRES and RES penetration in the final electricity consumption.

Comparing to the *Baseline* scenario (vRES = 73.5%, RES = 93.0%), both battery storage and demand-side flexibility enable to increase the penetration of renewable-based generation in the final consumption, while the scenario that explores only hydrogen reduces the contribution of these technologies as expected. Adding 2-4 h of battery capacity leads to modest gains, increasing RES to around 93.7%, reflecting improved short-term balancing. The strongest improvement is observed with the demand flexibility: a 5% demand flexibility raises RES to 95.6%, while 10% flexibility achieves a nearly 100-RES power system (vRES = 77.6%, RES = 97.8%). These results highlight that demand flexibility is crucial to maximise renewable integration, whereas rigid hydrogen demand can undermine system decarbonisation benefits if not coupled with operational flexibility solutions.

Figure 9.5 presents the share of vRES generation that is curtailed, expressed relative to the total potential generation from these technologies. The purpose of this analysis is to assess the efficiency of renewable energy integration and to identify any significant mismatch between energy supply and demand.

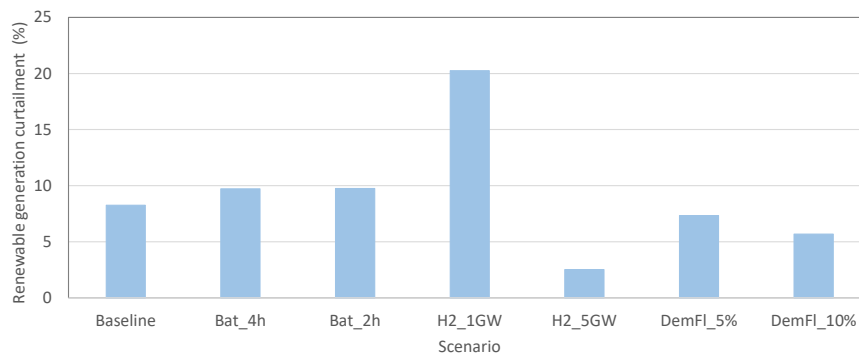


Figure 9.5. Share of vRES curtailment.

According to Figure 9.5, the curtailment in the *Baseline* scenario is 8.3%. The battery scenarios, despite adjustments in storage duration, show little effect on curtailment, suggesting that the installed capacity is insufficient to absorb the available renewable generation. This outcome can be explained by the strong mismatch between production and consumption, with excess generation occurring during periods of high solar output that exceed the nominal power of the batteries. The hydrogen scenarios highlight the strong influence of electrolyser capacity: 1 GW increases curtailment due to limited absorption of surplus renewables, while 5 GW substantially reduces it to 2.5%. Demand flexibility, increased from 5% to 10%, progressively lowers curtailment, confirming its effectiveness in balancing renewable variability. Hence, the results indicate that increasing the hydrogen capacity and



enhancing demand flexibility are the most impactful strategies for reducing renewable curtailment by 2030.

Furthermore, the capacity factors of batteries and electrolyzers provide additional insights regarding the power system performance (see Figure 9.6). Battery utilisation decreases with the reduction in the storage capacity to nearly 52% compared to the Baseline scenario (72.6%), highlighting the limited contribution to absorbing the surplus of renewable generation. In contrast, the H_2 scenarios cases show opposite behaviour: with 1 GW, the electrolyser utilisation factor increases to 57.9% due to full operation during surplus periods, while in the 5 GW case it decreases to 44.7%, reflecting the higher installed capacity and reduced operating hours. Nevertheless, these results indicate that, from an economic point-of-view, the expected hydrogen generation when RES surplus is available may not be sufficient to ensure the economic viability. The demand flexibility scenarios maintain high battery utilisation (around 75%) and moderate electrolyser use (about 47%), illustrating a more balanced and efficient system operation. These results reinforce that properly sizing flexible technologies and increasing demand flexibility are key to maximising renewable integration and minimising curtailment.

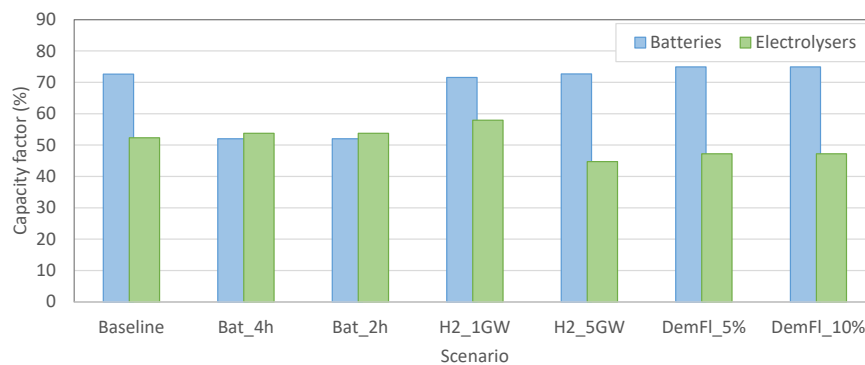


Figure 9.6. Annual capacity factor of batteries and electrolyzers.

Power system reliability and economic assessment: Table 9.3 presents key metrics associated with the power system, including the Energy Not Served (ENS), Loss of Load Probability (LOLP), and the average electricity cost assuming in the model a maximum of load shedding of 5%. For ENS, two measures are analysed: the maximum 1-hour ENS, representing the highest energy deficit observed in a single hour, and the maximum event ENS, representing the total energy deficit over consecutive hours of a single supply shortfall. These indicators provide insights into both the frequency and magnitude of supply deficits.

Table 9.3. Energy Not Served (ENS), Loss of Load Probability (LOLP), and Average Electricity Cost.

Scenario	Max. ENS (MWh)	Max Event ENS (MWh)	LOLP (%)	Average electricity cost (€/MWh)
Baseline	134	262	0.10%	32.74
Bat_4h	87	114	0.08%	33.63
Bat_2h	413	466	0.08%	36.09
H2_1GW	107	152	0.13%	70.58
H2_5GW	173	262	0.11%	42.86
DemFI_5%	524	524	0.08%	29.33
DemFI_10%	523	1265	0.06%	28.50



In the *Baseline* scenario, the maximum 1-hour ENS is 134 MWh, the maximum event ENS is 262 MWh, and LOLP is 0.10%, with an average electricity cost of 32.74 €/MWh. Battery storage of 4 hours reduces frequent small deficits, lowering maximum ENS to 87 MWh and LOLP to 0.08%, while slightly increasing costs. Shorter 2-hour storage concentrates deficits in fewer but larger events, reflected in higher max ENS (413 MWh) and event ENS (466 MWh), with a slightly lower LOLP (0.08%). Hydrogen at 1 GW provides limited reliability improvement but results in very high electricity costs (70.58 €/MWh), whereas 5 GW hydrogen reduces curtailment and LOLP (0.11%) with moderate costs (42.86 €/MWh). The increase in the demand flexibility enables to reduce the costs and LOLP; nevertheless, in this scenario concentrates deficits into very large events.

Interestingly, all ENS events occur between 19:00 and 20:00, coinciding with the evening peak in domestic electricity consumption. In all scenarios, gas-fired power plants were not activated in the Dispa-SET simulations. This is consistent with the optimal technical and economic dispatch assumptions of the model, which prioritises renewable generation, and storage based on system cost minimisation. However, in a real system, dispatchable conventional power plants might deviate from the purely optimal economic dispatch to ensure system security covering short-term peaks and avoid ENS events. The concentration of deficits within a single period highlights a critical mismatch between peak demand and the available fast-response flexibility, suggesting that batteries, demand-side management, or flexible operation of conventional plants would be essential to maintain the power system reliability. Therefore, the results emphasise the importance of aligning flexible resources with predictable daily load peaks, while recognising that conventional thermal plants may need to deviate from purely optimal economic dispatch to ensure system security in practice.

Evaluation of the performance of the MIBEL's day-ahead market from 2030 to 2050

The generation capacity of each country was optimised using the GENeSYS-MOD system within the scope of the European-funded ManOEUVRE. In specific, this work uses the version 1.2 scenario results. The optimal power system for each scenario was identified at a European level, although, in this work, the focus will be on the generation capacities of Portugal and Spain for 2030, 2040 and 2050, as illustrated in Figure 9.7.

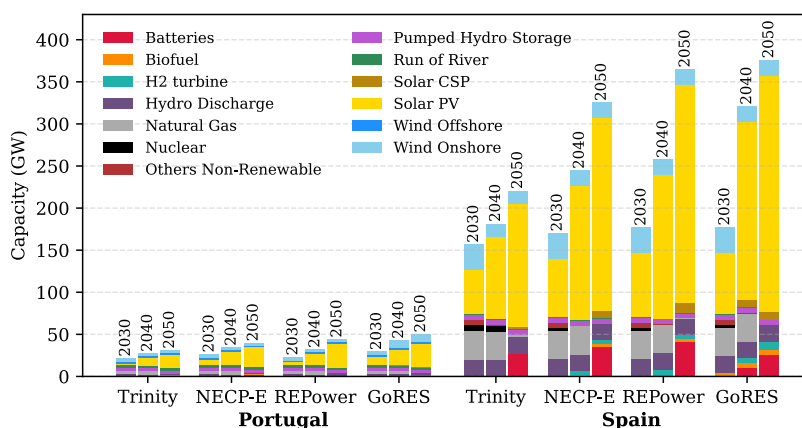


Figure 9.7. Installed capacity by technology in Portugal and Spain per scenario.

From Figure 9.7, it is possible to observe that solar PV emerges as the main technology in the Iberian electricity mix, especially in Spain. To support this massive solar growth, Spain also sees a significant rise in battery capacity by 2050, which is crucial to deal with the intrinsic variability of solar PV.



Portugal tends to maintain a more balanced portfolio despite the increase in solar PV capacity. Onshore wind capacity shows a downward trend across all scenarios in both countries, with offshore wind development being uniquely explored in Portugal. The EU Trinity scenario highlights the slight adoption of renewable technologies with a high dependence on fossil fuels. These results are strongly influenced by the European-scale optimisation used in the GENeSYS-MOD models, which prioritises cost-efficient dispatch across the continent. As a consequence, the MIBEL region shows a significant increase in installed solar capacity, while wind power is partially decommissioned in some scenarios. This increment is reflected in the evolution of the market-based share of RES in the electricity generation mixes of Portugal and Spain, as shown in Figure 9.8. In this figure, we observe that Portugal consistently maintains a higher renewable share than Spain across all scenarios, due to lower electricity demand, strong historical renewable deployment, flexible hydropower, and limited fossil reliance. By 2050, Portugal reaches 90.4% RES in the Go RES scenario, while Spain rises from 57–60% in 2030 to nearly 70%. In the EU Trinity scenario, Portugal achieves almost 88% RES, largely due to lower electricity consumption under geopolitical instability. For Portugal, electricity imports are very important in all scenarios.

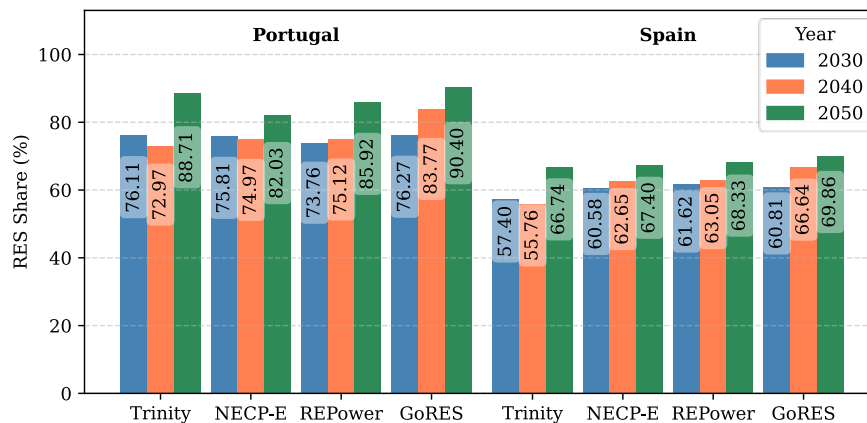


Figure 9.8. Market-based RES share for the Iberian Peninsula in the Man0EUvRE scenarios.

Day-ahead market captured prices: As expected, market prices generally decrease as renewable penetration rises, reaching their lowest levels in the REPower scenario at 28.02 €/MWh in Portugal and 18.78 €/MWh in Spain by 2050. As depicted in Figure 9.9, Spain consistently exhibits lower prices than Portugal due to the high level of low marginal cost technology as solar PV. Thus, as expected, the high level of low marginal cost technology as solar PV in the Iberian mix underlines the so-called “merit order effect” (Peña et al., 2022). Thus, as shown in Figure 9.10, a significant “cannibalisation effect” for solar PV across all pathways analysed is expected.

In the high ambition scenario Go RES, the captured price for solar falls to 4.32 €/MWh by 2050. This result emphasises the increasing economic challenge for solar assets in future electricity marginal-based markets.

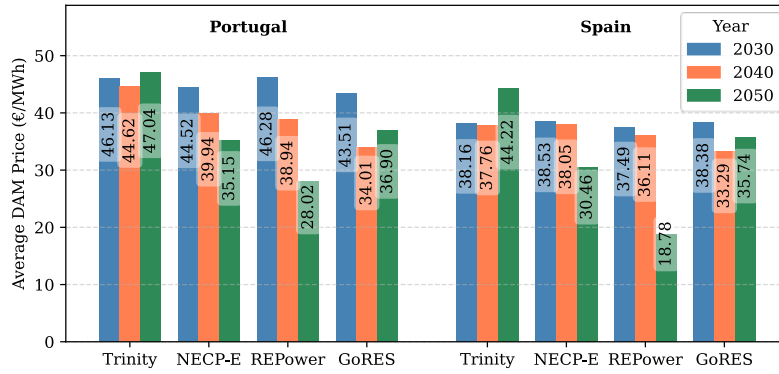


Figure 9.9. Evolution of the average day-ahead market price of electricity for Portugal and Spain across the scenarios analysed.

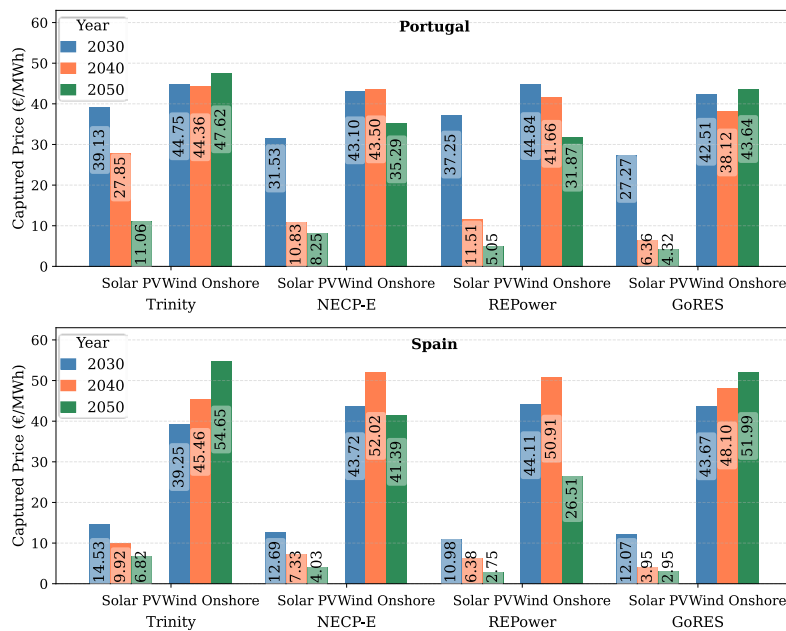


Figure 9.10. Captured market price of electricity for Portugal and Spain across the scenarios analysed.

On the other hand, results from previous figures, highlight that wind onshore and offshore maintain much higher and more stable captured prices, which is associated with the low installed capacity of these technologies in the Iberian region and the capability to produce in hours with highest market prices. These results are in line with existing literature that identifies a higher risk of cannibalisation by solar PV when compared with wind power (Yamujala et al., 2026). The NECP Essentials scenario, which reflects 2030 national energy and climate plans, exhibits a moderate price decline as targets are met. Nevertheless, a significant dependency on fossil fuels persists until 2040. In the EU Trinity scenario, this dependency is even more pronounced, resulting in the highest market prices across all pathways until 2050 due to the continued influence of high marginal cost thermal generation.

Market splitting events: The dynamics introduced by the large-scale integration of vRES show a strong impact on the number of market splitting events and, consequently, in the price divergences observed between Portugal and Spain, Figure 9.11.

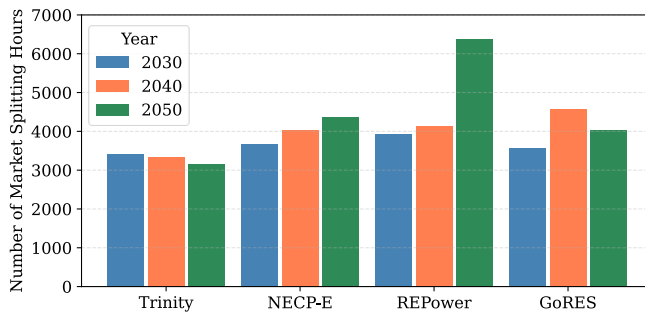


Figure 9.11. Market splitting events in MIBEL for the scenarios analysed.

In scenario REPowerEU++, the number of market splitting hours increases significantly, reaching over 6000 hours by 2050, indicating that interconnection capacity is fully congested nearly 73% of the time. This finding indicates persistent transmission constraints. Thus, although both countries are advancing in decarbonisation of power system, limited interconnection capacity and the generation mixes of both countries can lead to frequent price divergences, with Portugal facing higher prices during congestion periods. However, as vRES capacity continues to grow, often with similar generation profiles, the planned interconnection reinforcement may not be sufficient in the long-term to accommodate all cross-border transactions and prevent frequent market splitting events.

Overall, the findings of day-ahead market simulation emphasise that achieving the expected decarbonisation requires a balanced pathway that aligns renewable expansion with flexibility measures and grid reinforcement, as this is essential to deliver efficient price signals, ensure investment viability, and sustain renewable growth without long-term reliance on public support.

9.4.2. NECP

Portugal has set ambitious renewable energy targets in the 2024 update of its 2030 NECP and it also foresees an increase in electricity consumption associated with industry and electrolyzers, which directly affects generation and system planning. While the NECP's modelling primarily focuses on domestic decarbonisation without considering the interconnection with Spain, the GENeSYS-MOD model adopts a pan-European optimisation perspective. This broader scope captures cross-border electricity flows and interactions between national energy systems, which have a strong impact in the results. As a result, the outcomes obtained with GENeSYS-MOD (v1.2) indicate, for instance, the decommissioning of certain technologies, such as wind power, while showing strong investment in solar PV in the Iberia region. By integrating these pan-European dynamics, the model highlights the trade-offs between domestic targets and system-wide efficiency. These complementary insights could be valuable for the NECP's national approach, but they must also take supply security into account. Figure 9.12 provides a summary of the installed capacity established in the Portuguese NECP and foreseen in the NECP Essential (v1.2) scenario.

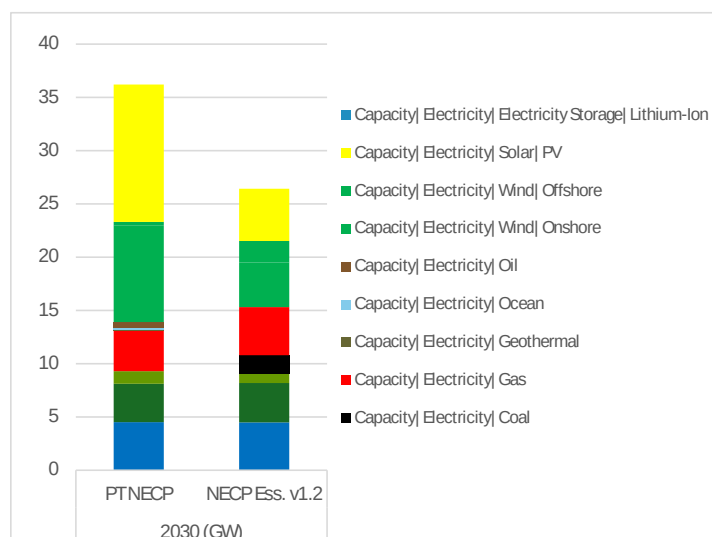


Figure 9.12. Installed capacity in Portuguese NECP and foreseen in the NECP Essential (v1.2) scenario.

9.4.3. Supplementary Data

All datasets and configuration files used for assessment of the impact of flexible solutions using the NECP are derived from open and reproducible data sources, primarily the TradeRES project database (Helistö et al., 2024) and complemented with information from the Portuguese NECP 2030. Historical time series of generation, consumption and hydro reservoir storage available at the Portuguese transmission system operator from 2019 were used¹⁶. The modelling framework is based on the publicly available Dispa-SET model.

The performance of the MIBEL day-ahead market from 2030 to 2050 was evaluated using outputs from GENeSYS-MOD version 1.2, in combination with the PyMIBEL-DAM tool, which is publicly accessible at <https://github.com/AntCouto/PyMIBEL-DAMSimulator> and includes examples as well as the results for v1.2 in the IAMC format (folder “IAMC”). Due to the volume of information, the full dataset is available upon request by contacting the corresponding authors.

16 REN DataHub. DataHub Portugal. <https://datahub.ren.pt/pt>



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